RELIABILITY, RESILIENCE AND THE ONCOMING WAVE OF RETIRING BASELOAD UNITS, VOLUME II-C: FUEL-ELECTRICITY INTERACTION IN THE NORTHEAST AND MIDCONTINENT

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Disclaimer

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LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

AGTP	Algonquin Gas Transmission pipeline
Bcf/d	Billion cubic feet per day
Bcf/yr	Billion cubic feet per year
BES	Bulk electric system
CT	Connecticut
DOE	Department of Energy
DEOK	Duke Energy Ohio/Kentucky
EMM	Electricity Market Module
FERC	Federal Energy Regulatory Commission
GW	Gigawatt
ISO	Independent system operator
ISO-NE	ISO New England
L48	Lower 48
LMP	Locational marginal price
LNG	Liquefied natural gas
MA	Massachusetts
MB NAGM	MarketBuilder World Gas Model with a focus on North America
Mcf	Thousand cubic feet
MESA	Mission Execution and Strategic Analysis
MISO	Midcontinent Independent System Operator
MMBtu	Million British thermal unit
MW	Megawatt
MWh	Megawatt-hour
NE	Northeast
NERC	North American Electricity Reliability Corporation
NETL	National Energy Technology Laboratory
NGL	Natural gas liquids
NJ	New Jersey
NYISO	New York Independent System Operator
O&M	Operation and maintenance
PA	Pennsylvania
PJM	PJM Interconnection
QGESS	Quality Guidelines for Energy System Studies
REX	Rockies Express
RI	Rhode Island
RRC	Railroad Commission
RTO	Regional transmission organization
TETCO	Texas Eastern Transmission Pipeline
TGP	Tennessee Gas Pipeline
U.S.	United States
VA	Virginia
WECC	Western Electricity Coordinating Council

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EXECUTIVE SUMMARY

There have been two extreme cold weather events in the Northeast region of the U.S. in the past six years. Each event taxed the region in multiple ways, including putting strain on both the bulk electric system (BES) and the natural gas infrastructure. The all-time Eastern Interconnection coincident winter peak load[1] took place during the polar vortex weather event in the winter of 2013-2014. This weather event resulted in price events in both regional electricity and natural gas.

This study aims to investigate how future cold weather events might affect regions as their generation fleet continues to shift away from baseload coal and nuclear plants and toward natural gas units and renewables. In particular, this study explores the potential effects of simulated extreme winter weather events in the northeastern U.S. from 2018 through 2025, how that weather might affect the BES and natural gas infrastructure and market performance, and how might the electricity and natural gas markets respond to increased demand on the system?

A total of four scenarios are explored in each region. A normal, business-as-usual case (Normal) is compared with three scenarios using a winter season with the Polar Vortex peak electricity demand with differing assumptions around generation capacity retirements and additions. The first "Expected" scenario features expected generation retirement, the second "At-Risk" scenario features additional retirement of nuclear and coal units deemed at-risk for retirement, and the third "No Retirements" scenario assumes that all known and at-risk unit retirements do not retire.[2]

Using the Deloitte MarketBuilder (MB) North American Gas Model (NAGM) and ABB PROMOD, this study applies the historical peak electricity demands of the Polar Vortex as a basis to the regional electricity market models for ISO New England (ISO-NE), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Midcontinent Independent System Operator (MISO). MB NAGM and PROMOD were applied through an iterative process to create dynamic natural gas market prices and electric sector demands. Electric sector natural gas demands are passed from PROMOD into MB NAGM, which in turn passes natural gas prices back to PROMOD, to create a more robust picture of both electricity and natural gas markets than either system can accomplish alone.

The MB NAGM was modified with increased demand and system constraints, corresponding to the past extreme weather of the Polar Vortex, and capacity expansion limitations corresponding to the expected lead time requirements to implement not-yet-planned and publicly announced capacity expansions.[3] Four regional PROMOD models were configured using up-to-date ISO

[1] All-time Eastern Interconnection coincident winter peak load is the peak of the total coincident electricity load for the entire Eastern Interconnection. These values were calculated using historical data from ABB Velocity suite (4)

[2] This analysis does not attempt to examine the long-term or year-round economic viability of any generating resource or infrastructure system, it only seeks to study the effects of differing resource profiles on system and market response and infrastructure needs under normal (50/50) and elevated (90/10) demand stress scenarios.

[3] Interstate pipeline permitting and construction, including expansion of existing pipelines, takes on average 38 to 46 months depending on whether the pre-filing or traditional process is utilized by the permittee and the Federal Energy Regulatory Commission (FERC). See NETL Issues in Focus – Building Interstate Natural Gas Transmission for more details. (7)

models, with historical electricity demand corresponding to the Polar Vortex. Electricity sector natural gas demand and natural gas pricing were passed between models until convergence criteria had been met, at which point results were extracted from both models.

Normal projected demand for natural gas in winter drives high natural gas prices in constrained demand areas like New England relative to non-winter seasons. When increased winter demand is modeled in the scenarios, total gas demand is constrained by the existing and currently expected infrastructure, and prices must increase further to ration supply among demands. These higher prices of natural gas make new pipeline capacity economic to construct. However, because it is assumed that pipeline projects not already in advanced development cannot be financed, permitted, and constructed before 2023, underlying winter demand can outstrip capacity in certain areas during the years leading up to 2023. Dracut hub in New England is an example of a constrained area. These resulting high prices for natural gas (even under normal winter demand) cause higher prices for electricity as expressed through ISO-NE location marginal prices (LMP).

Under all three high winter demand scenarios, high pipeline utilization and natural gas prices during winter support infrastructure capacity expansion. Along certain pipelines, utilization rose up to 60-100 percent for the winter periods in 2019-2023. These periods of high utilization (and high prices) moderate once the model can begin endogenous[4] capacity expansion in 2023. Capacity expansion in these models resulted in an additional 3.5 - 6.6 billion cubic feet per day (Bcf/d) of pipeline capacity, across different scenarios.

High gas price periods lead to increases in power prices as well. Periods of high gas pipeline utilization result in high natural gas pricing information being passed to the PROMOD models. Natural gas hub prices above $70 per million British thermal unit (MMBtu) are seen in extreme cases. All four study regions showed sensitivity to increased natural gas pricing in varying degrees. MISO showed the most distance from the weather effects (among Eastern Interconnection regions), and the least amount of sensitivity to higher gas prices in its region, showing LMP increases of $1-$3 per megawatt-hour (MWh). PJM showed the next highest sensitivity with price increases up to $22/MWh above normal. NYISO and ISO-NE showed the most sensitivity to natural gas price spikes, with NYISO showing $150/MWh increases, and ISO-NE showing $400/MWh price increases above normal.

Natural gas production across the scenarios is constrained prior to 2023. Production potential exists to meet the simulated elevated demand in winter; however, the limit of pipeline capacity prevents supply from increasing to meet demand. The higher prices that result from the constrained delivery to demand acts to reduce consumption as some demands are unwilling to pay the higher prices and other generation becomes economic to dispatch instead of gas-fired units.

As the generation fleet shifts away from baseload coal and nuclear plants, and more heavily into natural gas and renewable generation sources, further strain will be placed on regions already

[4] *Endogenous* refers to results of the economic modeling solutions, therefore endogenous capacity expansions are those capacity expansions found in the modeling to be economically supported. Endogenous is contrasted with *exogenous* which refers to inputs specified to the model. Therefore, exogenous capacity expansions are those assumed and scheduled, regardless of the economics, perhaps because they are already under construction or already permitted and planned.

heavily invested in single fuel sources when that fuel source is affected. The loss of a diverse electricity fuel mix may magnify the effects of future extreme weather events.

1 INTRODUCTION

Two cold weather events, namely the "Polar Vortex" during the winter of 2013–2014, and the "Bomb Cyclone" during the winter of 2017–2018, exerted pressure on the bulk electric system (BES) in the Northeastern, Mid-Atlantic, and Midwestern regions of the United States (U.S.). During both events, the regional transmission organizations (RTO) and independent system operators (ISO) in these regions experienced high wholesale electricity prices that corresponded to spikes in the price of natural gas. ISO New England (ISO-NE), New York Independent System Operator (NYISO), and PJM Interconnection (PJM) were primarily affected, although Midcontinent Independent System Operator (MISO) also experienced extreme temperatures and higher than average electricity and natural gas demand.

There is uncertainty regarding how the BES will withstand similar events in the future. With 21,600 MW[5] of baseload nuclear and coal-fired capacity expected to retire by 2023 (capacity that supplied electricity during these winter events), the RTOs/ISOs will need to develop new capacity to continue meeting peak winter demand. This is complicated by an increasing reliance on natural gas-fired capacity to supply electricity demand on the coldest days of the year in regions where natural gas demand for heating peaks during those same days.

In order to better understand how the affected RTO/ISOs—ISO-NE, NYISO, PJM, and MISO—may respond to future events, this study models three possible future scenarios using two modeling platforms—ABB PROMOD and MarketBuilder. PROMOD is a commercially available, security-constrained, unit commitment, and economic dispatch model that models individual generator units, regional to local generation, and transmission system information out to the limits of operation for the North American BES. PROMOD provides reliable data availability in a set of off-the-shelf models that cover the major energy markets. In this instance, hourly, seasonal, and annual time slices adjusted for seasonality and annual macroeconomic factors are used.

MarketBuilder is a commercially available economic modeling platform; a derivative of the MarketBuilder World Gas Model with a focus on North America (MB NAGM) is used to provide full economic modeling of natural gas supply chains, including basin supply and production, transport, multi-sector demand, and natural gas liquids (NGL) supply and demand. MB NAGM contains several functional layers including gas production (in 42 regions), gas demand (in 65 regions), and gas pipelines containing market hubs that link with supply, demand, and/or other hubs. Capacity limits along these links can represent aggregated corridors or specific pipeline segment capacities. Additional layers cover NGLs and liquefied natural gas (LNG). The MB NAGM is structured on a monthly time-scale with storage that can be economically utilized or operated on a specific injection/withdrawal schedule.

[5] Total capacity of all announced retirements in these regions.

The study scenarios model the interaction between electric generation demand and fuel supply by iterating economic dispatch analysis performed using the PROMOD platform with natural gas supply and pricing analysis using the MarketBuilder platform. Given some of the differences in the approaches between MarketBuilder and PROMOD, using both platforms gives a deeper picture of system performance and possible outcomes under different scenarios, as fuel prices are an exogenous input to PROMOD and power sector demand is exogenous to MB NAGM, while the reverse are endogenous to each.

2 FUTURE DEMAND SCENARIO METHODOLOGY

With a goal of evaluating system and market performance in the power and gas sectors under high winter demand situations, a set of three scenarios was developed and analyzed. In addition to the three scenarios, a baseline assuming normal weather/demand was also executed for comparison with the scenarios. These four cases span the 2018–2025 period.

The aim of this modeling exercise is to evaluate

1. what electricity demand could be in future years in ISO-NE, NYISO, PJM, and MISO should they experience high winter demand;
2. what natural gas demand would be in service of that electricity demand; and
3. if there would be enough natural gas supply, given infrastructure constraints, to meet the demand for electricity, space heating, commercial, and industrial utilization.

While high winter demand was modeled only in the Eastern Interconnection, the scenarios were run for all asynchronous North American interconnections overseen by the North American Electric Reliability Corporation (NERC).[6] The power systems are generally separate across interconnections with relatively limited transfer capability between interconnections in comparison to the transfer capability within each interconnection. In contrast to the separation that exists in the power system, the natural gas pipeline network interacts across more regions. While increased power demand in one interconnection may have no impact on the power prices in another interconnection, increased gas demand in one part of the country may not only increase gas prices in that region but also increase gas prices across neighboring and other regions. Higher power demand in the Eastern Interconnection can lead to increased gas demand from the power sector of the Eastern Interconnection. That same increased power demand will not likely lead to a rise in generation in the Western, Texas, or Quebec Interconnections, but the associated increased gas demand in the Eastern Interconnection could cause gas prices in those regions to increase, which could reduce economic gas demand from the gas consuming sectors in those regions.

The scenarios used in this study were built using models updated according to the National Energy Technology Laboratory (NETL) Quality Guidelines for Energy System Studies (QGESS): Economic Dispatch Modeling Guidelines for NETL Studies Version 1.0 (3) and modified as necessary for the study. The scenarios differ based on assumptions about electricity demand and power plant retirements, as shown in Exhibit 2-1. The baseline scenario, referred to as Normal or the "Normal" case, has a 50/50 winter demand assumed in each region, along with certain capacity additions and retirements. Certain retirements include all power plants that have announced their retirements through 2025. This "Normal" is used as a reference for all others.

[6] The NERC overseen North American power system is currently comprised of four asynchronous interconnections, comprising the entire continental U.S., Eastern and Western Canada, and Northern Baja California. These interconnections are known as the Eastern Interconnection, which encompasses most of the U.S. and Canada east of the Rockies, less Quebec; the Quebec Interconnection, which encompasses the province of Quebec; the Texas Interconnection, which encompasses most of the state of Texas; and the Western Interconnection which encompasses the U.S. and Canada west of the Rockies and Northern Baja California.

Exhibit 2-1. Scenarios*

No.	Scenarios	Retirements	Demand
0	Normal	expected	Normal (50/50)
1	Expected	expected	high winter (90/10)
2	At-Risk	expected + At-Risk	
3	No Retirements	prior to Oct 2018	

*A 50/50 demand forecast is a probabilistic demand forecast that has a 50 percent chance of being exceeded by actual demand and is normally understood to represent moderate, average weather conditions; likewise, a 90/10 forecast has a 10 percent probability of being exceeded and is normally representative of severe weather conditions.

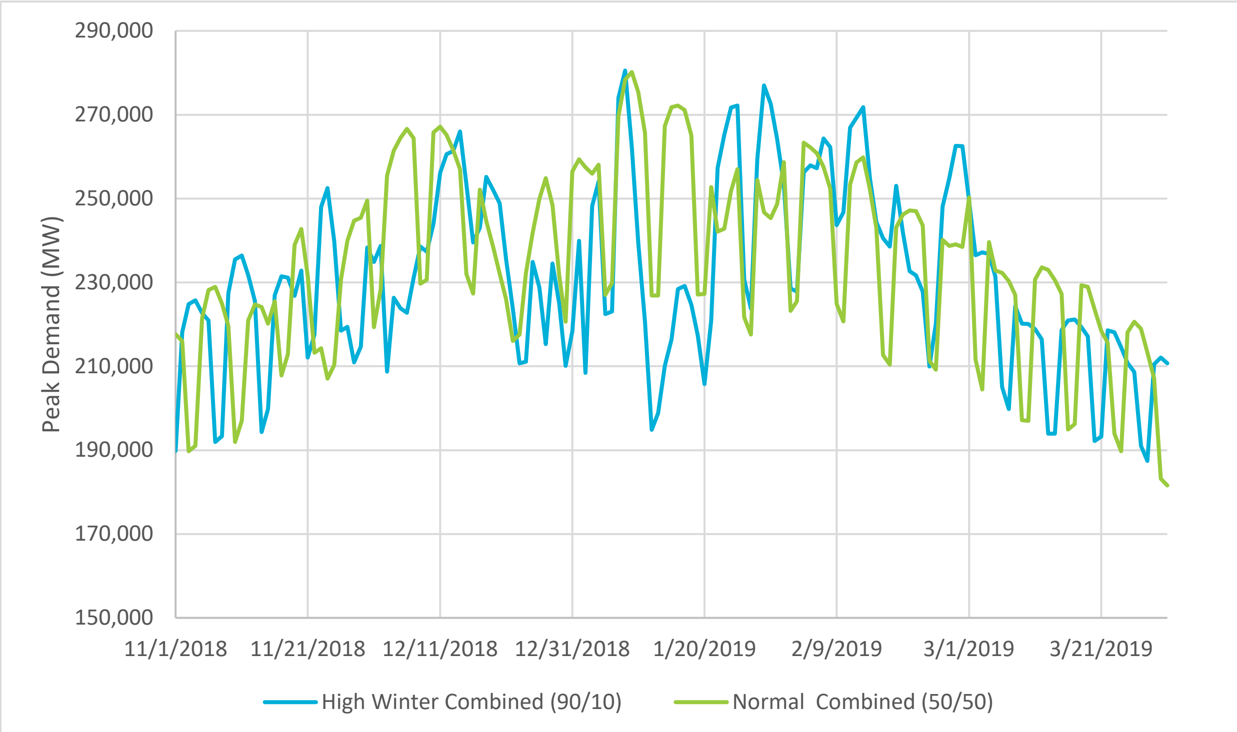
The Expected, At-Risk, and No Retirements were each run with a 90/10 high winter demand. High winter demand was based on

- elevated MWh power demand in the Eastern Interconnection during the winter season—December, January, and February—for PROMOD; and
- elevated Mcf natural gas demand for residential, commercial, and industrial sectors in the Eastern Interconnection.

The elevated power and natural gas demands was estimated by adding regional demand growth rates[7] to the all-time high coincident Eastern Interconnection peak power load that was experienced during winter 2013–2014, the same winter the Polar Vortex occurred. This historical hourly demand for November 1, 2013, to February 28, 2014, was applied directly to the model for November 1, 2018, to February 28, 2019. In the winter months from 2019 to 2025, growth rates for demand for each region were calculated from existing load forecasts, and the 2013–2014 winter demand was adjusted using those factors. Exhibit 2-2 shows the combined daily peak load (i.e., the High Winter Combined) of the four regions studied, compared to the latest normal load forecast available for these regions (i.e., Normal Combined). The 2018 load forecast (Normal Combined) comes close to the peak from 2014, with the Polar Vortex demand (High Winter Combined) having four more large peaks above the normal forecast.

[7] Growth rates were calculated according to (3)

Exhibit 2-2. Combined peak demand (MW) comparison (PJM, MISO, ISO-NE, NYISO) (2019)



The initial generating fleet to which changes were applied in each of the scenarios matches that which was in-service in on January 1, 2018. With changes applied, the "Expected" configuration uses expected unit retirements in the future, based on those plants that have announced retirement dates. The "At-Risk" configuration, adds to the expected retirement list units that have been identified as At-Risk of retiring, based on unit statistics and operational history, as well as media reports on possible retirements.[8] The "No Retirements" configuration, includes only retirements that were implemented by October 2018, and assumes no further retirements beyond that time. Plants that have announced retirements beyond October 2018, are assumed to remain available under this scenario.

Exhibit 2-6 show the yearly retirements and additions to each region under Expected. The MISO region retires mostly coal generation and adds a significant quantity of renewables to replace it. ISO-NE retires some nuclear, with renewables and natural gas units coming in to replace it. NYISO sees gas and nuclear retirements, with primarily gas units being added. Coal and nuclear retirements in PJM are replaced primarily by natural gas units.

[8] Retirement estimates ranked units using projected results from the Annual Energy Outlook data broken out by Electricity Market Module (EMM) (very close to NERC's Subregions) by each unit's adjusted production cost of electricity. Parameters included in determining the adjusted cost were the baseline production cost (including fuel cost, variable and fixed operation and maintenance [O&M], emission control costs (if controls are required to be added included amortized capital cost and O&M costs, and life extension cost (if unit is greater than 30 years old, which included amortized capital cost and a sliding scale of exposure to full life extension cost based on age). Once a unit's adjusted production costs were determined, it was ranked with all other units in its EMM and the cumulative capacity was summed according to ranking. Units with announced retirements were moved to the top of the retirement ranking and were categorized as compared to cumulative retirements in each EMM.

Exhibit 2-3. Expected Scenario: MISO generation retirements and additions

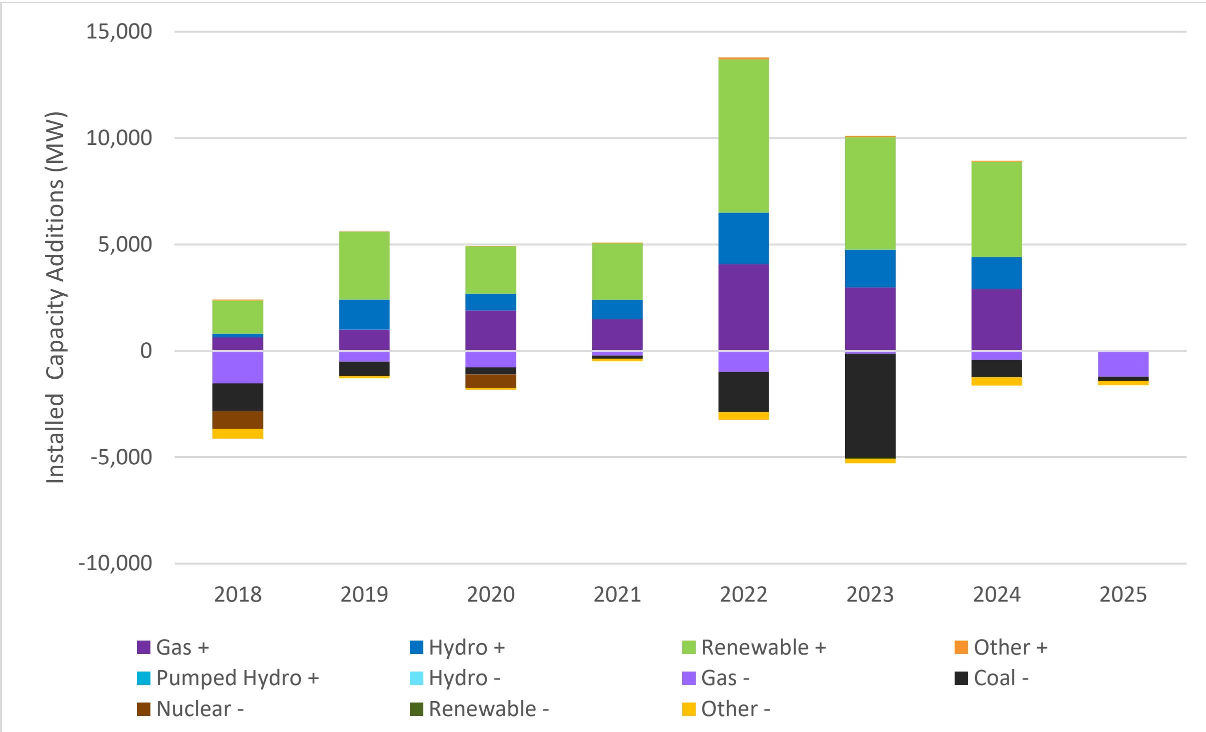


Exhibit 2-4. Expected Scenario: ISO-NE retirements and additions

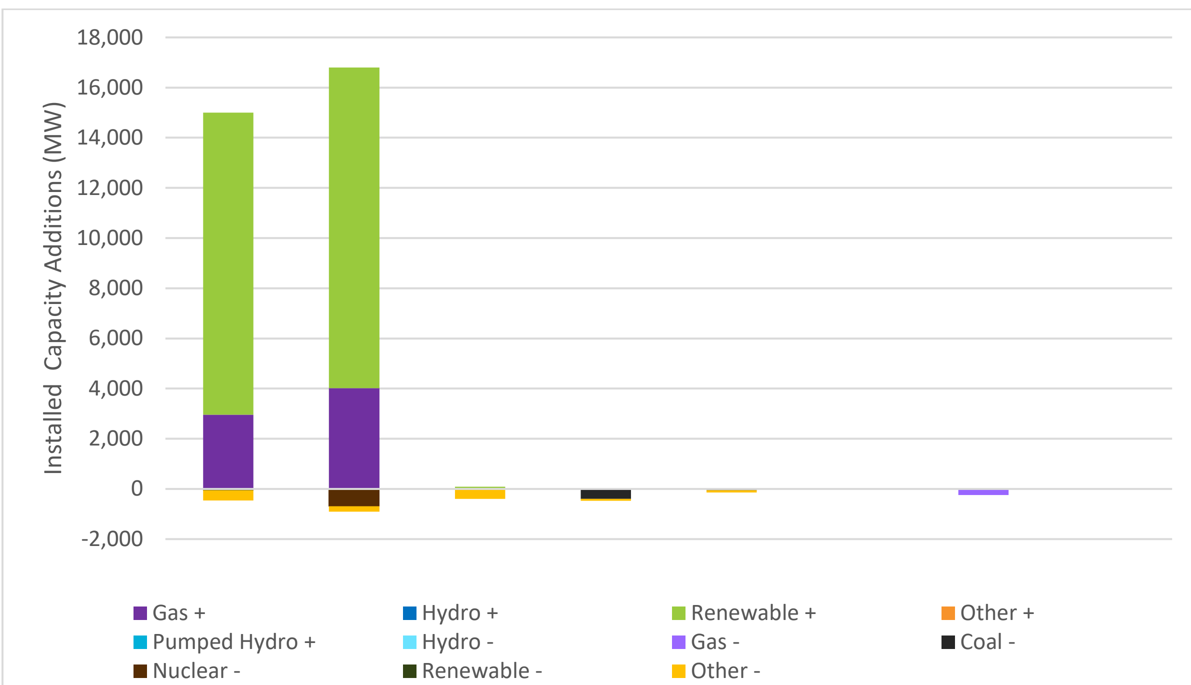


Exhibit 2-5. Expected Scenario: NYISO retirements and additions

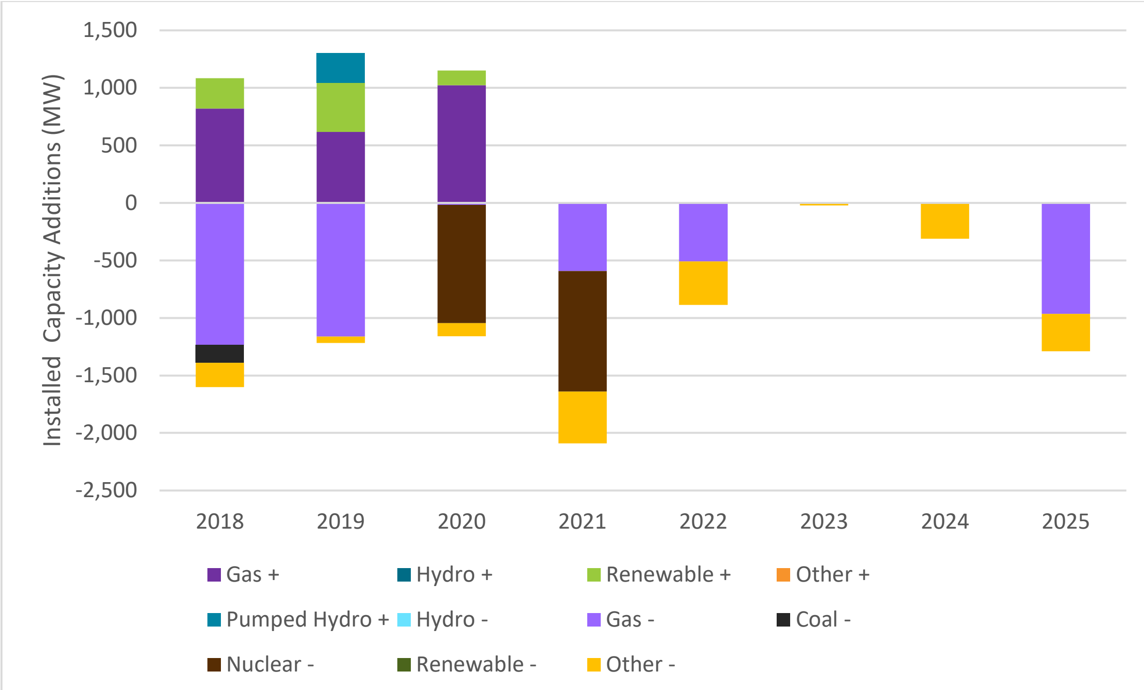


Exhibit 2-6. Expected Scenario: PJM retirements and additions

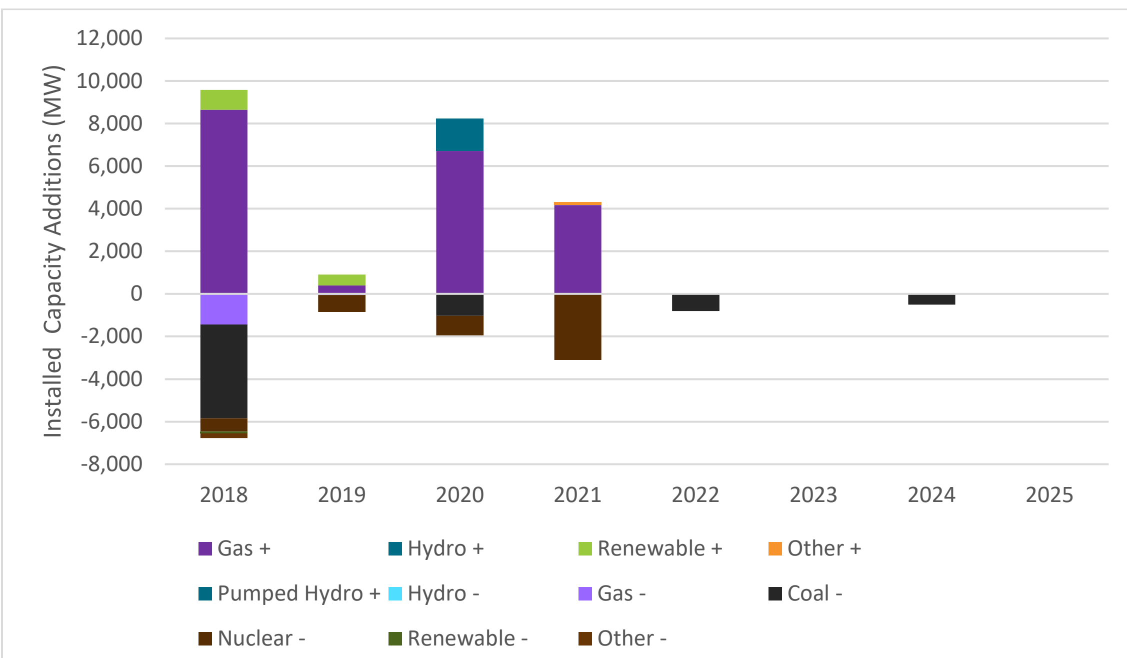


Exhibit 2-7 summarizes the regional fleet changes expected for each RTO/ISO. In the table, "Anticipated" capacity includes Certain Capacity scheduled to come online during the study period, whereas "Prospective" capacity includes Uncertain Capacity that is added to meet the NERC planning reference reserve margins in each region.[9]

Exhibit 2-7. Expected Scenario: Summary of regional fleet changes*,[10]

Capacity (MW)		Coal	Natural Gas-CC	Natural Gas-Other	Nuclear	Hydro	Renewable	Other	Total
MISO	Anticipated	-10,259	2,324	-5,734	-1,459	2,748	4,067	-1,903	-10,215
	Prospective	0	12,695	0	0	6,164	22,473	273	41,605
	Regional Total	-10,259	15,019	-5,734	-1,459	8,912	26,540	-1,630	31,390
ISO-NE	Anticipated	-466	2,232	101	-684	-1	6,463	-1,183	6,462
	Prospective	0	0	4,385	0	0	18,440	0	22,825
	Regional Total	-466	2,232	4,486	-684	-1	24,903	-1,183	29,287
NYISO	Anticipated	-154	2,411	-4,260	-2,077	260	820	-1,863	-4,863
	Prospective	0	2,892	159	0	0	0	0	3,051
	Regional Total	-154	5,303	-4,101	-2,077	260	820	-1,863	-1,812
PJM	Anticipated	-6,757	19,176	-425	-5,423	0	1,403	-252	7,722
	Prospective	0	0	0	0	0	0	0	0
	Regional Total	-6,757	19,176	-425	-5,423	0	1,403	-252	7,722
Grand Total	Anticipated	-17,636	26,143	-10,318	-9,643	3,007	12,753	-5,201	-895
	Prospective	0	15,587	4,544	0	6,164	40,913	273	67,481
		-17,636	41,730	-5,774	-9,643	9,171	53,666	-4,928	66,586

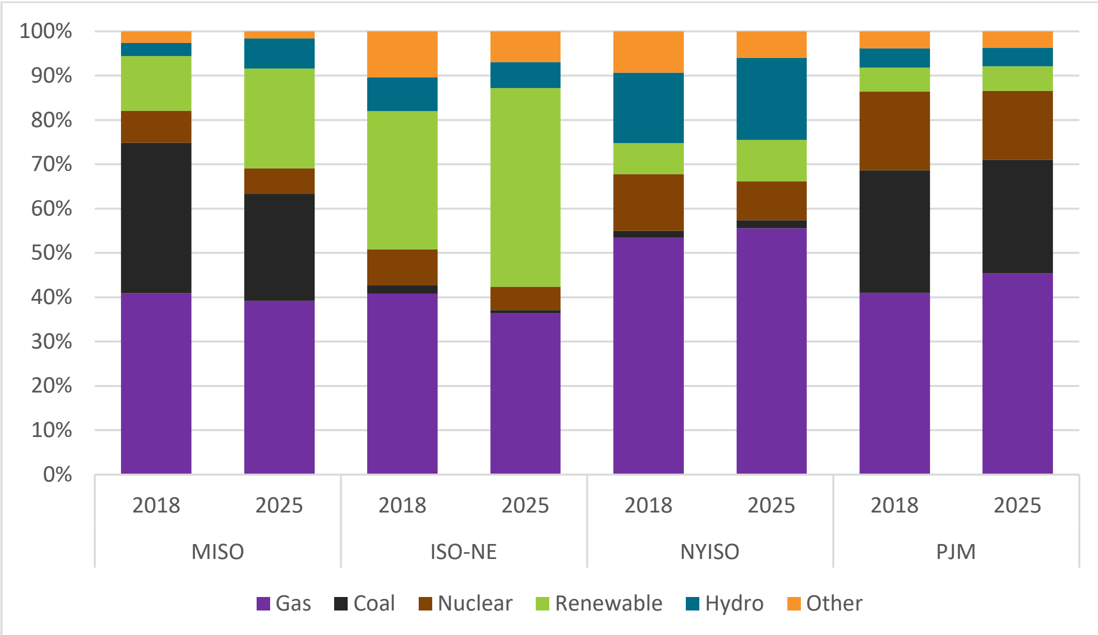
*Anticipated represents expected and certain additions and retirements; prospective represents unconfirmed, at-risk, and uncertain additions and retirements.

Exhibit 2-8 compares the resource mix from 2018 to 2025 under Expected. Each region changes in different ways, as the share of gas in MISO and ISO-NE decreases slightly (by 1 percent and 5 percent, respectively) and increases in NYISO and PJM (by 2 percent and 4 percent, respectively). In place of gas and coal, renewables experience strong growth in MISO (from 12.4 percent to 22.6 percent) and ISO-NE (from 31.2 percent to 44.8 percent). In NYISO, renewables only increase an additional 2 percent, and in PJM renewables remain steady. Nuclear experiences modest declines (between 2 and 4 percent) in each region.

[9] Certain Capacity includes generating units listed within the Active Generation Queue that are permitted and under construction. Uncertain Capacity is generation not in the Active Generation Queue that has been added for the region to meet the NERC planning reference reserve margins.

[10] For comparison of changes to total fleet sizes for each region, see Appendix A: Scenario Fleet Comparison

Exhibit 2-8. Expected Scenario: Resource mix



At-Risk adds the retirement of plants deemed At-Risk of retirement. Plants that already have an announced retirement date will retire on that day as planned. At-risk plants with no announced retirement date are modeled as retired in 2020. Exhibit 2-9 through Exhibit 2-12 show the additions and retirements for the four regions in At-Risk. The retirement of at-risk plants results in an additional 16.6 gigawatt (GW) of coal retirements, and 1.7 GW of nuclear retirements across the 4 models. Combining with those from the expected case brings the total to 34 GW of coal retirements and 11 GW of nuclear retirements.

Exhibit 2-9. At-Risk Scenario: MISO retirements and additions

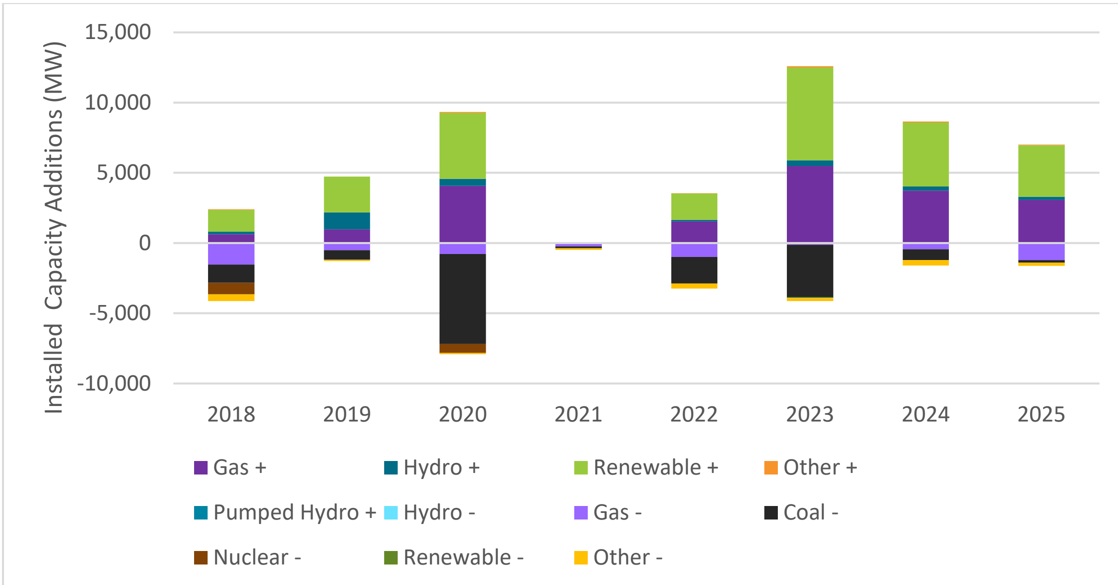


Exhibit 2-10. At-Risk Scenario: ISO-NE retirements and additions

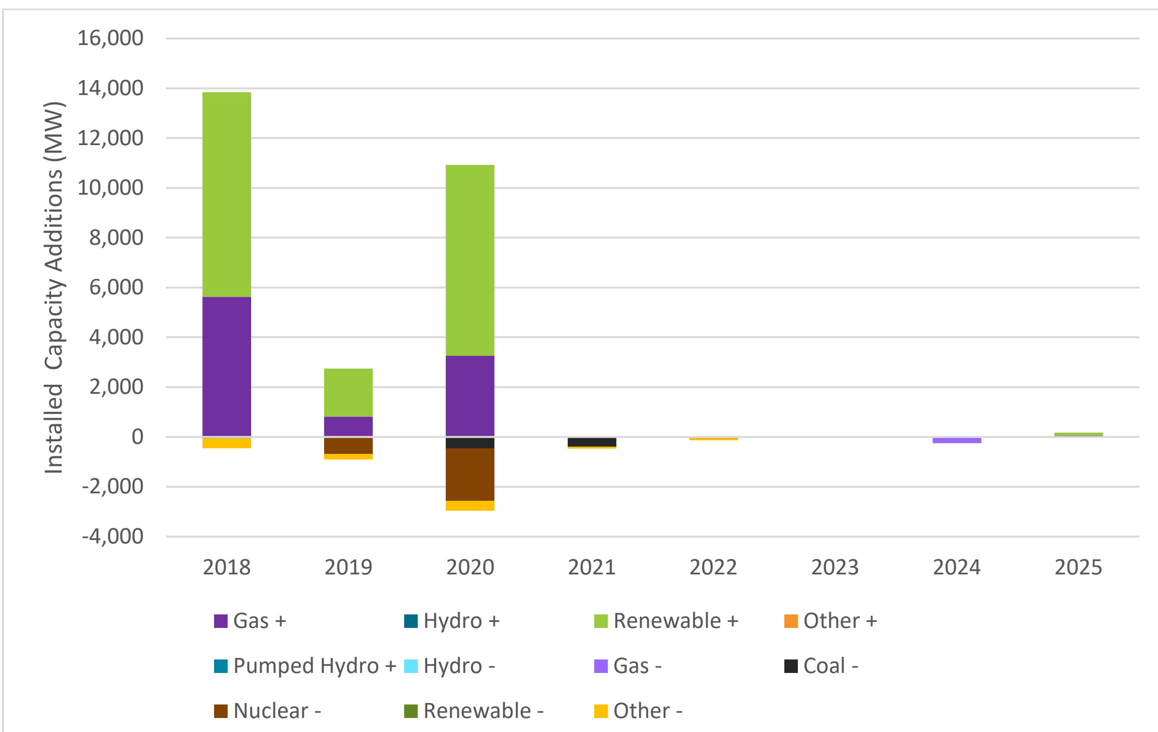


Exhibit 2-11. At-Risk Scenario: NYISO retirements and additions

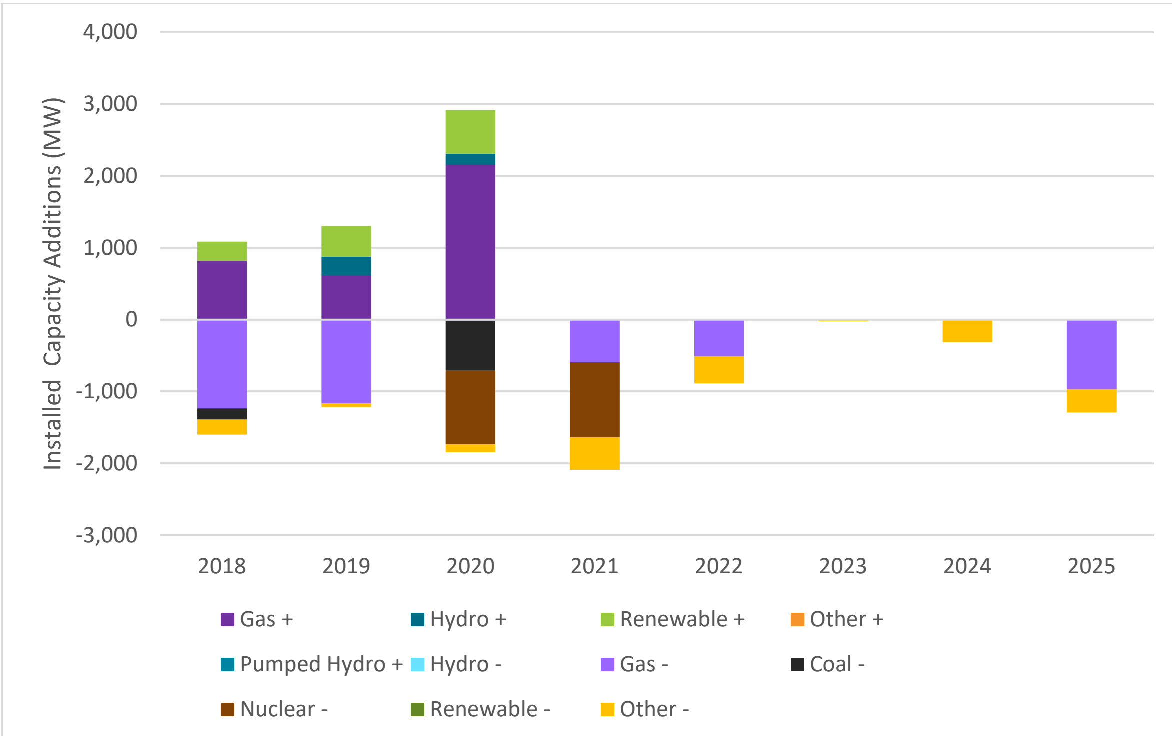


Exhibit 2-12. At-Risk Scenario: PJM retirements and additions

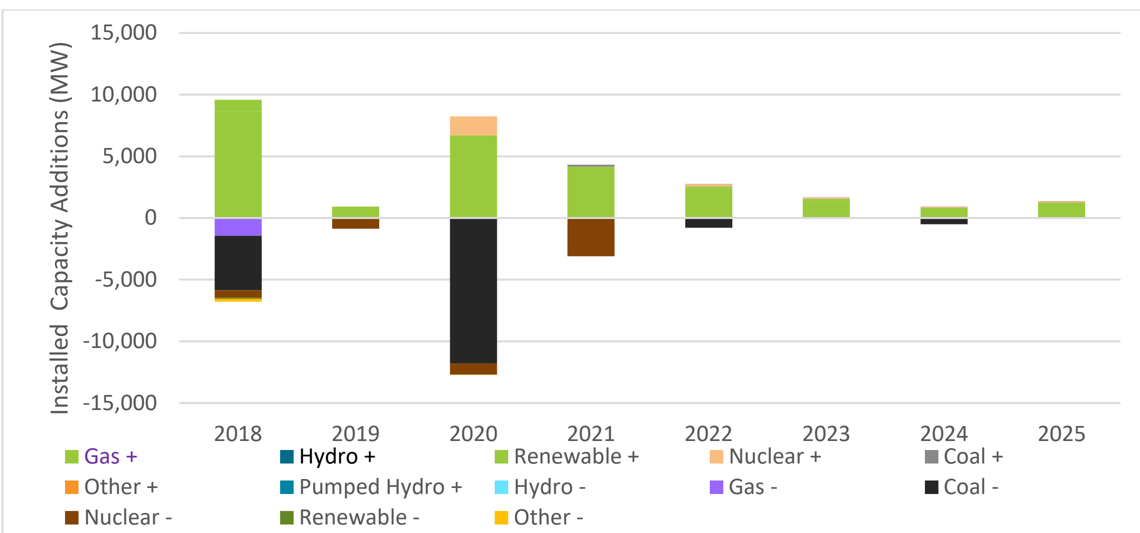


Exhibit 2-13 provides a summary of the expected additions and losses in generation for each ISO.

Exhibit 2-13. At-Risk Scenario: Summary of regional fleet changes*[11],

Capacity (MW)		Coal	Natural Gas-CC	Natural Gas-Other	Nuclear	Hydro	Renewable	Other	Total
MISO	Anticipated	-15,152	2,324	-5,734	-1,459	1,560	4,948	-402	-13,914
	Prospective	0	17,223	0	0	1,281	20,536	250	39,290
	Regional Total	**-15,152**	**19,547**	**-5,734**	**-1,459**	**2,842**	**25,484**	**-152**	**25,376**
ISO-NE	Anticipated	-918	2,232	101	-2,795	-1	402	-1,183	-2,162
	Prospective	0	7,530	0	0	0	17,512	0	25,042
	Regional Total	**-918**	**9,762**	**101**	**-2,795**	**-1**	**17,914**	**-1,183**	**22,880**
NYISO	Anticipated	-841	2,411	-4,260	-2,077	311	981	-1,863	-5,339
	Prospective	0	907	50	0	101	320	0	1,378
	Regional Total	**-841**	**3,318**	**-4,210**	**-2,077**	**412**	**1,301**	**-1,863**	**-3,961**
PJM	Anticipated	-17,387	19,176	-425	-5,423	0	1,355	-244	-2,941
	Prospective	40	5,690	91	440	0	398	0	6,659
	Regional Total	**-17,347**	**24,866**	**-334**	**-3,463**	**0**	**1,753**	**-244**	**3,711**
Grand Total	Anticipated	-34,298	26,143	-10,318	-11,754	1,870	7,686	-3,692	-24,363
	Prospective	40	31,350	141	440	1,382	38,766	250	72,369
		-34,258	**57,493**	**-10,177**	**-11,314**	**3,252**	**46,452**	**-3,442**	**48,007**

*Anticipated represents expected and certain additions and retirements; prospective represents unconfirmed, at-risk, and uncertain additions and retirements.

In all four regional models, additional natural gas and renewable capabilities are the primary additions used to ensure each region meets its NERC planning reserve margin based upon the procedure outlined in the Guideline for Developing Economic Dispatch Models for NETL Studies. (3) The overall changes to the capacity mix in each region is illustrated Exhibit 2-14. Under At-Risk, the resource mix in 2025 shifts away from coal and nuclear generation towards natural gas and renewables when compared to 2018.

[11] For comparison of changes to total fleet sizes for each region, see Appendix A: Scenario Fleet Comparison

Exhibit 2-14. At-Risk Scenario: Resource mix

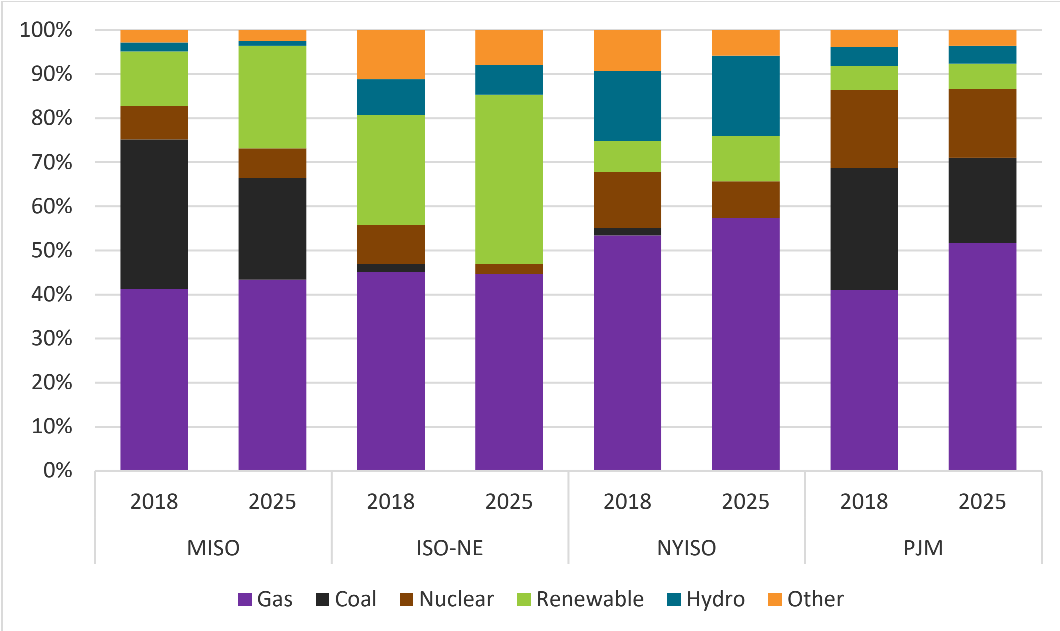


Exhibit 2-15 through Exhibit 2-18 show the model additions and retirements for No Retirements. Halting the retirement of coal and nuclear units past 2018 results in fewer natural gas and renewable resources being brought online as replacement and to meet reserves. Exhibit 2-19 summarizes these retirements for each ISO.

Exhibit 2-15. No Retirements Scenario: MISO retirements and additions

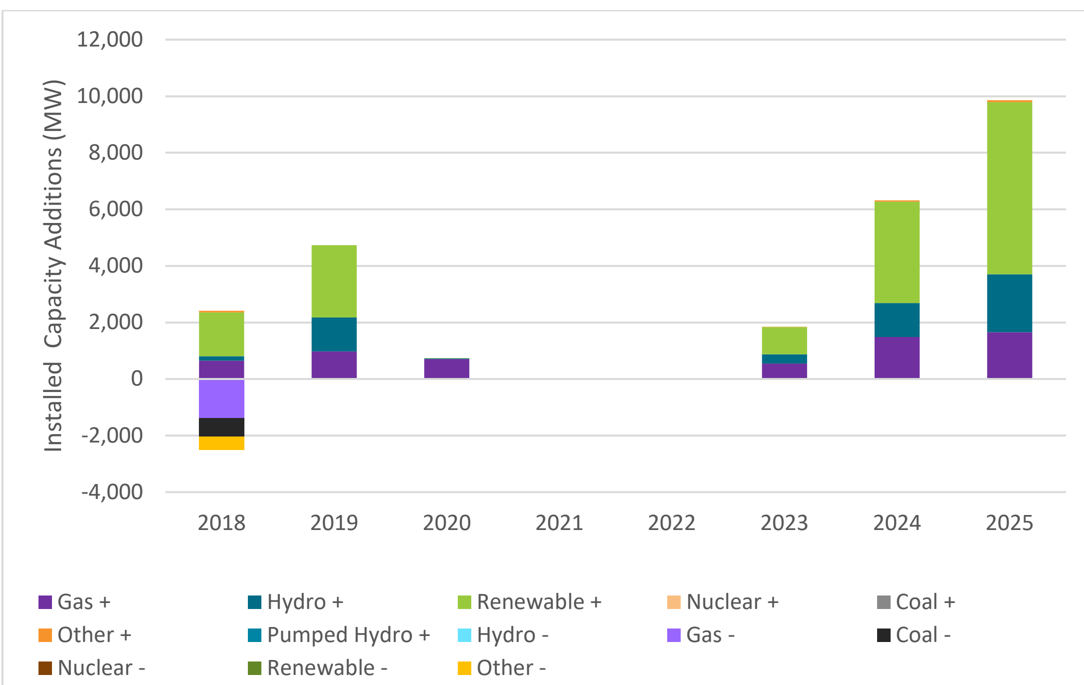


Exhibit 2-16. No Retirements Scenario: ISO-NE retirements and additions

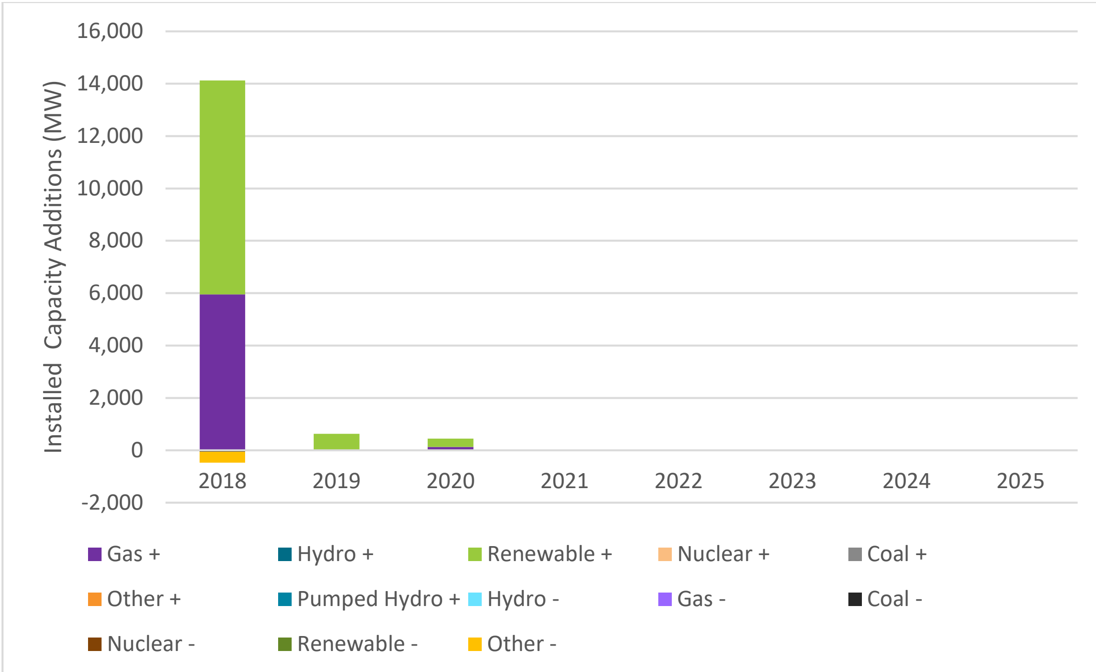


Exhibit 2-17. No Retirements Scenario: NYISO retirements and additions

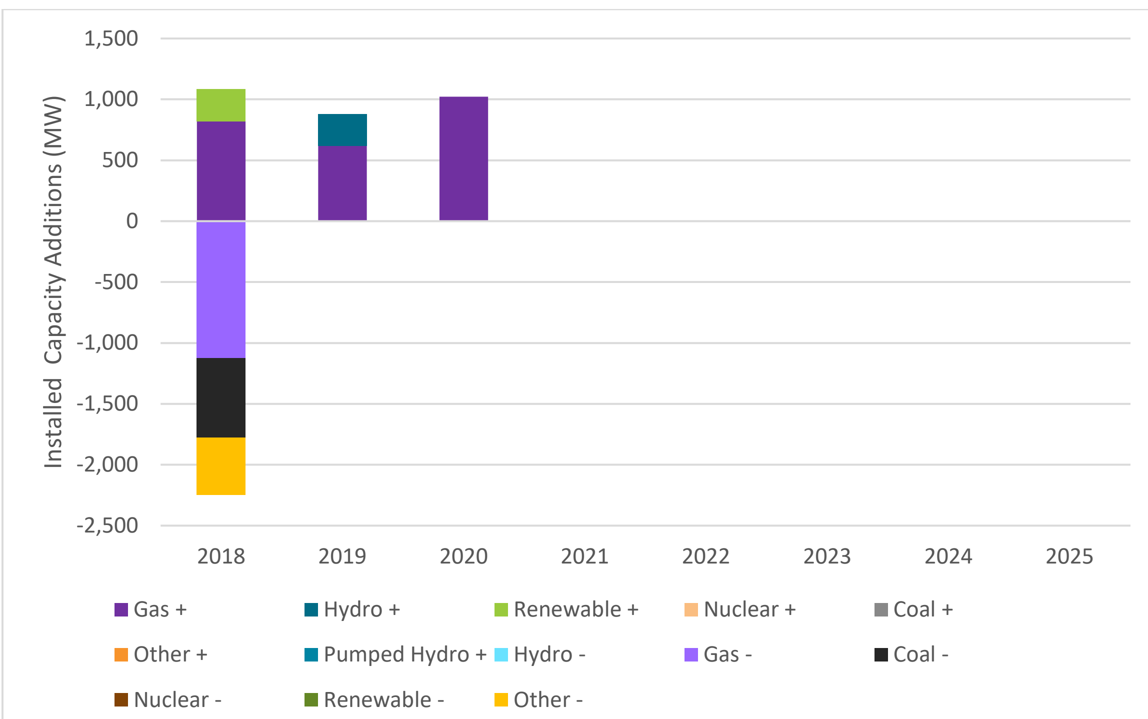


Exhibit 2-18. No Retirements Scenario: PJM retirements and additions

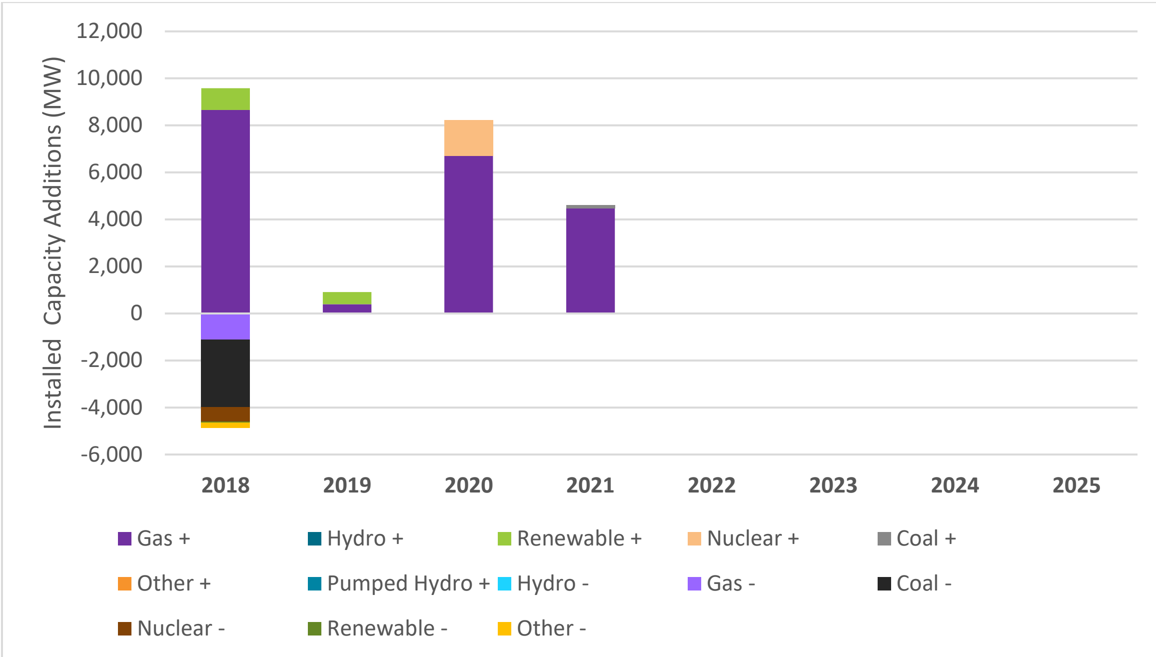


Exhibit 2-19. No Retirements Scenario: Summary of regional fleet changes*, 12

Capacity (MW)		Coal	Natural Gas-CC	Natural Gas-Other	Nuclear	Hydro	Renewable	Other	Total
MISO	Anticipated	-658	2,324	-1,383	0	2,775	8,244	-370	6,581
	Prospective	0	3,677	0	0	2,193	6,514	79	12,463
	Regional Total	-658	6,001	-1,383	0	4,968	14,758	-291	19,044
ISO-NE	Anticipated	-48	2,232	101	0	0	319	-397	2,207
	Prospective	0	0	3,772	0	0	8,775	0	12,547
	Regional Total	-48	2,232	3,873	0	0	9,094	-397	14,754
NYISO	Anticipated	-658	2,411	-1,121	0	260	266	-470	688
	Prospective	0	0	0	0	0	0	0	0
	Regional Total	-658	2,411	-1,121	0	260	266	-470	-2,451
PJM	Anticipated	-2,737	19,176	-55	906	0	1,445	-229	18,942
	Prospective	0	0	0	0	0	0	0	0
	Regional Total	-2,737	19,176	-55	906	0	1,445	-229	18,942
Grand Total	Anticipated	-4,101	26,143	-2,458	906	3,035	10,274	-1,466	32769
	Prospective	0	3,677	3,772	0	2,193	15,289	79	25,010
		-4,101	29,820	1314	906	5,228	25,563	-1,387	57,779

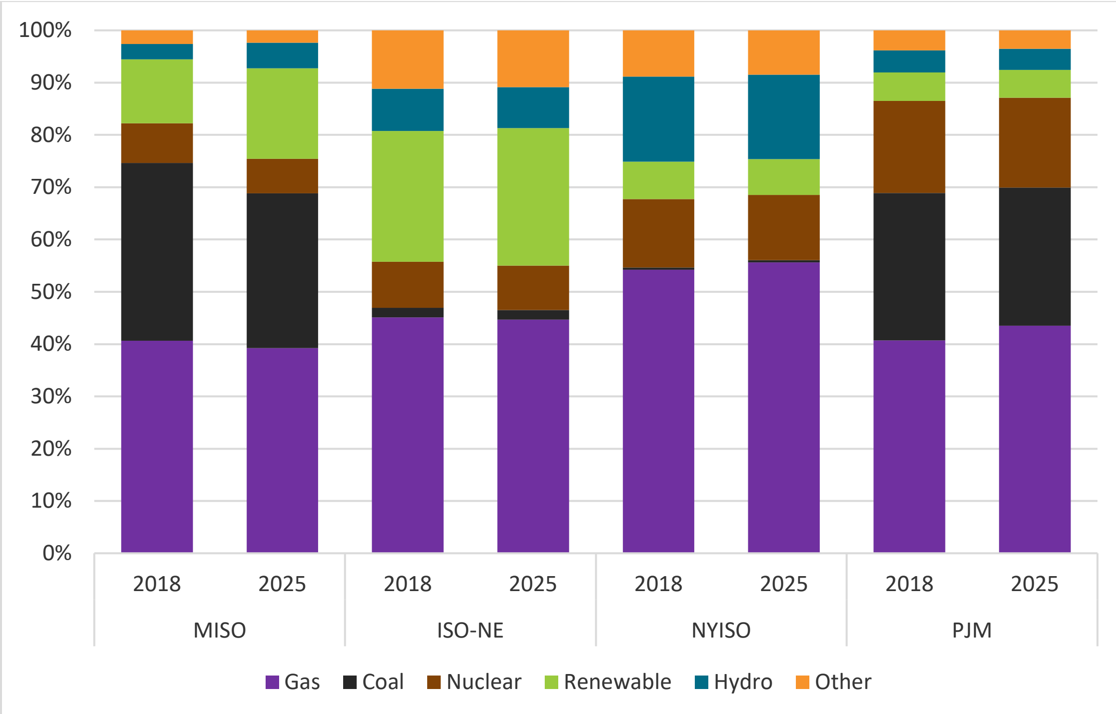
*Anticipated represents expected and certain additions and retirements; prospective represents unconfirmed, at-risk, and uncertain additions and retirements.

The No Retirements scenario assumes coal and nuclear generation that was planned or expected to retired is retained.[13] In some regions, due to retirements, additional generation is required to meet NERC reference reserve margin levels. The impact of retaining coal and nuclear units that would have retired is most pronounced in ISO-NE and NYISO. Under No Retirements, there is a more diverse asset mix projected, as seen in Exhibit 2-20, when compared to Expected and At-Risk.

[12] For comparison of changes to total fleet sizes for each region, see Appendix A: Scenario Fleet Comparison

[13] These units were not given special treatment such as 'must-run' status but were left in the model to operate when determined by merit order dispatch based on their respective dispatch price, which incorporates all of the costs of continued operation.

Exhibit 2-20. No Retirements Scenario: Resource mix

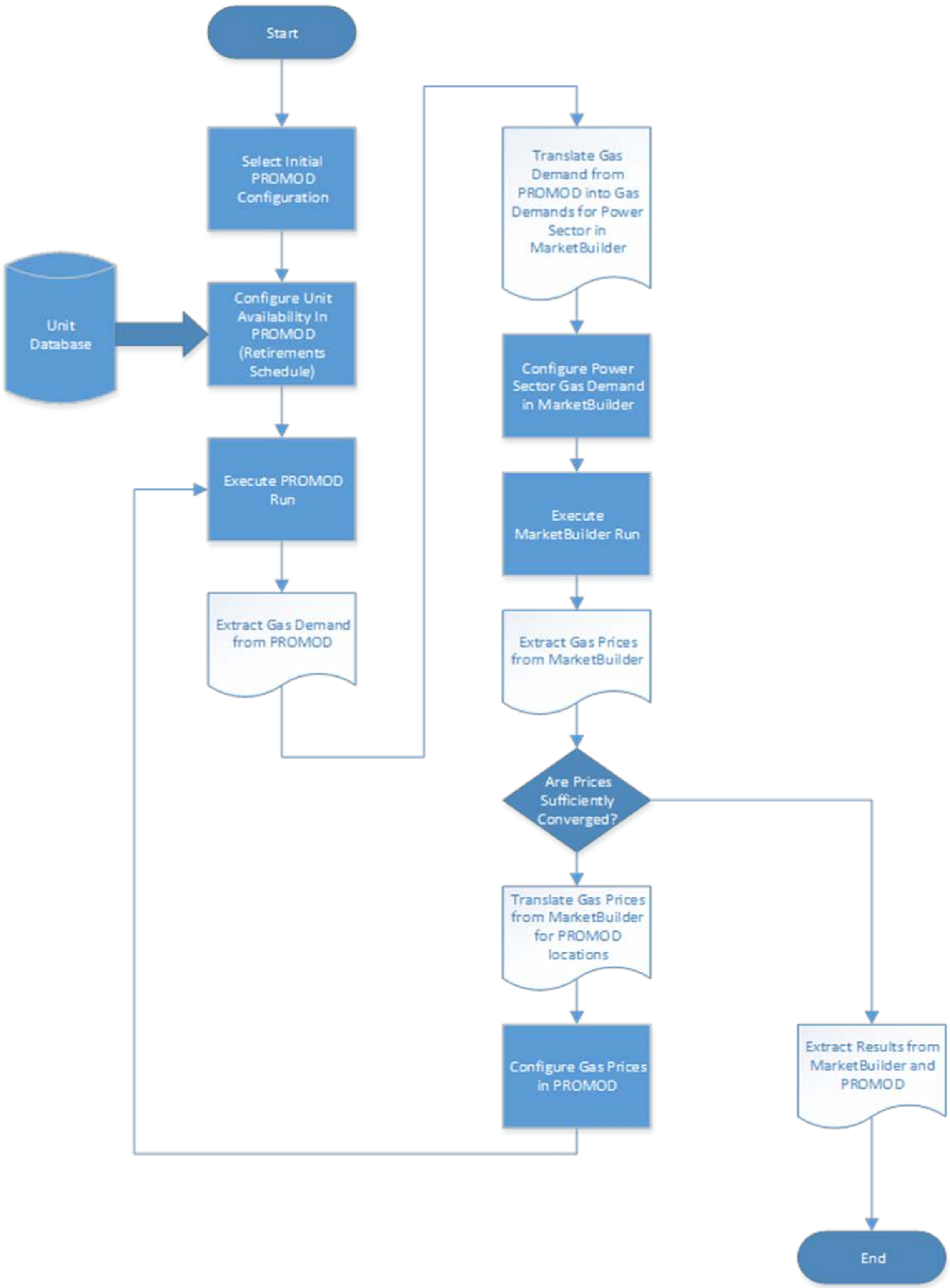


In all of the scenarios, MB NAGM allowed new, economically-supported natural gas infrastructure to be built endogenously beginning in 2023, which is the earliest new pipelines not already under current development and in the permitting process could be expected to go into service. Prior to 2023, any natural gas infrastructure constraints that occurred could not be resolved with new infrastructure not already under current development.

For each scenario configuration, an iterative process between the two models was performed, as illustrated in Exhibit 2-21.An initial run with PROMOD created a set of gas demands by model region based on the economic dispatch of gas-fired units versus other generation. These regional gas demands were used to adjust the power sector gas demand in a MarketBuilder model run. The MarketBuilder run determined regional gas pricing based on the economic fundamentals of supplying the various demands across the system, including the power sector demands established by the prior PROMOD run. If the regional gas prices from the MarketBuilder run were sufficiently different from the gas prices used in the PROMOD run, those gas prices were updated and the process repeated until the two models were converged, that is, when the situation where the gas prices and power sector gas demands were consistent across both models.[14] Each scenario begins at the same starting fuel prices, but were iterated separately, to arrive at different fuel price forecasts resulting from the different scenario assumptions.

[14] Convergence criteria is this instance is defined as the difference in natural gas volumes between iterations of the two models to be within a tolerance range of 5 percent for major market hubs. For hubs with small flows (large changes due to limited natural gas fired generation plants causing the plants to be either dispatched or shut down due to price changes between models during iterations) a larger tolerance up to 15 percent was allowed.

Exhibit 2-21. Model integration process flowchart



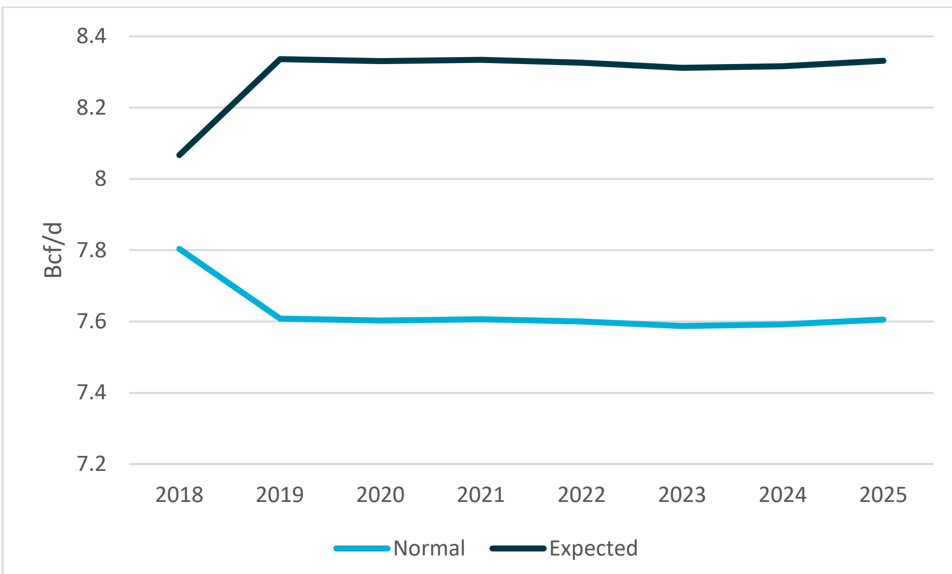
3 Future Demand Scenario Results

Results for each scenario have been grouped into winter periods, which begin in December and extend through February. Each winter period is named for the year of the December in which it begins—Winter 2018, for example, includes December 2018–February 2019.

3.1 Natural Gas Demand

Exhibit 3-1 compares annual core gas demand between Normal and Expected for Northeastern states including New England, Mid-Atlantic, and Appalachia. Core gas demand refers to residential and commercial gas demand. The chart does not include industrial gas demand because that sector's demand is not as sensitive to temperature/weather as the core market and would not differ significantly between the Normal and scenario cases such as Expected. Gas demand for power generation is considered separately from core demand because its seasonal variation differs from core seasonality, and power sector demand depends on generation capacity mix and fuel prices over time.

Exhibit 3-1. Core gas demand



Core gas demand for Normal declines from 2018 to 2019 because actual realized demand for the early months of 2018 were utilized, and the beginning of 2018 was colder than normal. For 2019 and beyond, Normal is based on normal weather, and therefore lower demand in winters than what was experienced in early 2018.[15]

The core gas demand is the resulting volume of gas consumed, taking into account any consumption reaction to gas prices (demand elasticity). Residential and commercial gas consumption is mainly for space and water heating. Without viable alternate heating sources at

[15] The Energy Information Administration Annual Energy Outlook 2018 assumes that residential and commercial consumption will drop slightly from 2018 to 2019 due to a cold winter in 2018 followed by the anticipation of a normal winter in 2019.

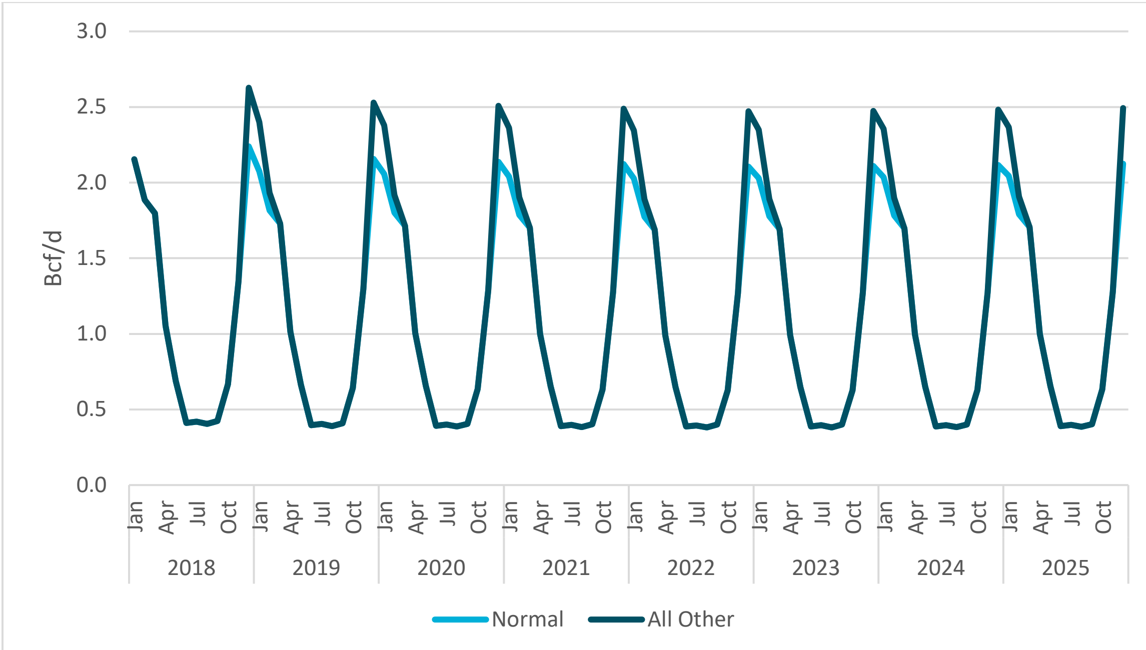
a comparable price, core gas consumption is almost inelastic, which shows in the rise in consumption with colder temperatures in Expected when compared to Normal.

The elevated core gas demand caused by the Polar Vortex assumption in the scenarios such as Expected generally affects the winter months of December, January, and February. At the time of the analysis in 2018, it was already known that early 2018 was colder than normal, but not to the degree of the Polar Vortex. Therefore, the Polar Vortex elevation in demand were applied to the December to February periods starting in December 2018. This results in the years from 2019 onward having higher core demand than 2018, because each of the later years would have three elevated months (January, February, and the following December) whereas 2018 would only have December comparably elevated for the Polar Vortex (and January 2018 and February 2018 elevated to a lesser degree based on realized actual demand).

Growth in core demand over future years is very small and as seen in the chart remains relatively stable through the following years. In the other three scenarios, the winter core gas demand for each of the Northeastern states has been increased by a proportional factor based on the observed actual increase during the Polar Vortex of the 2013–2014 winter season. Beyond 2019, the Normal shows no appreciable growth through 2025. The Expected, At-Risk, and No Retirements scenarios show the increase in core gas demand due to the assumed colder-than-normal temperatures starting with Winter 2018–2019 and into the future.

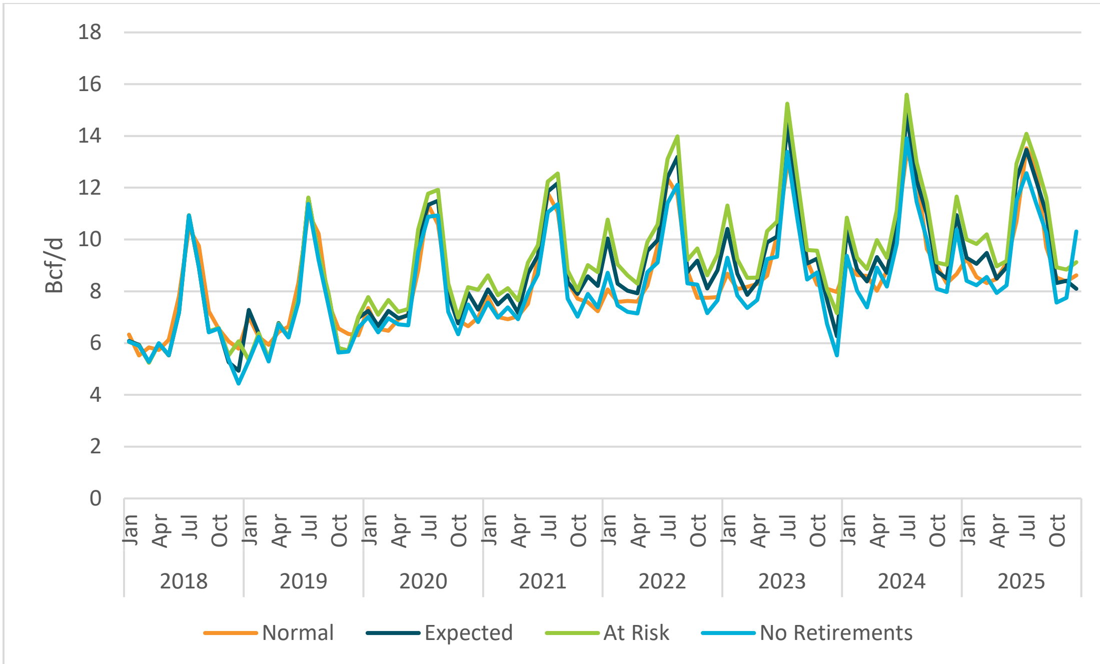
Exhibit 3-2 compares the seasonality of the monthly New England core demand between Normal and the other three scenarios. Non-winter gas demand was assumed to be the same as Normal. Demand during Winter 2018–2019 (December 2018, January and February 2019) was increased from 184 Bcf in Normal to 209 Bcf in the other three scenarios, a 14 percent increase over the three winter months. The non-winter months’ (March 2018 to November 2018) core demand remained the same in all cases at 216 Bcf over the nine-month period. The winter stress demand increase remained the same over all future winter years.

Exhibit 3-2. Monthly New England core gas demand 2018–2025



The total demand, which includes the core (residential and commercial space heating), industrial, and gas demand for power generation, grows in Normal at an average of about 2.5 percent per year. In Expected, the growth rate averages about 3.4 percent per year, depending on the amount of gas consumed in the power sector, which itself depends on the dispatch levels and the amount of retirement of coal and nuclear units modeled in each case. Gas demand for power generation was generated in the PROMOD dispatch model for Normal and the three other scenarios. The gas demand varies over the years depending on the amount of coal and nuclear generation capacity retired in each case, the amount of gas generation added in each case, and the natural gas price at each of the power hubs modeled in the PROMOD model and the MarketBuilder model. As shown in Exhibit 3-3, the gas demand for power generation grows over time. The average difference between the Normal and At-Risk scenarios is 0.7 Bcf/d. Further, average annual power sector gas demand levels in No Retirements, Expected, and At-Risk are successively higher, matching the progressively increased amount of solid fuel generation capacity retired in each case. In the scenarios, declines in natural gas consumption from the power sector, as seen in late 2018 and early 2024, are the result of natural gas price spikes that result in lower use of natural gas for power generation.

Exhibit 3-3. Monthly Northeastern States power generation gas demand 2018–2025



3.2 Natural Gas Transportation Infrastructure

Exhibit 3-4 shows some of the major natural gas pipelines included in the scenario runs.

Exhibit 3-4. Selected major natural gas pipelines (4)

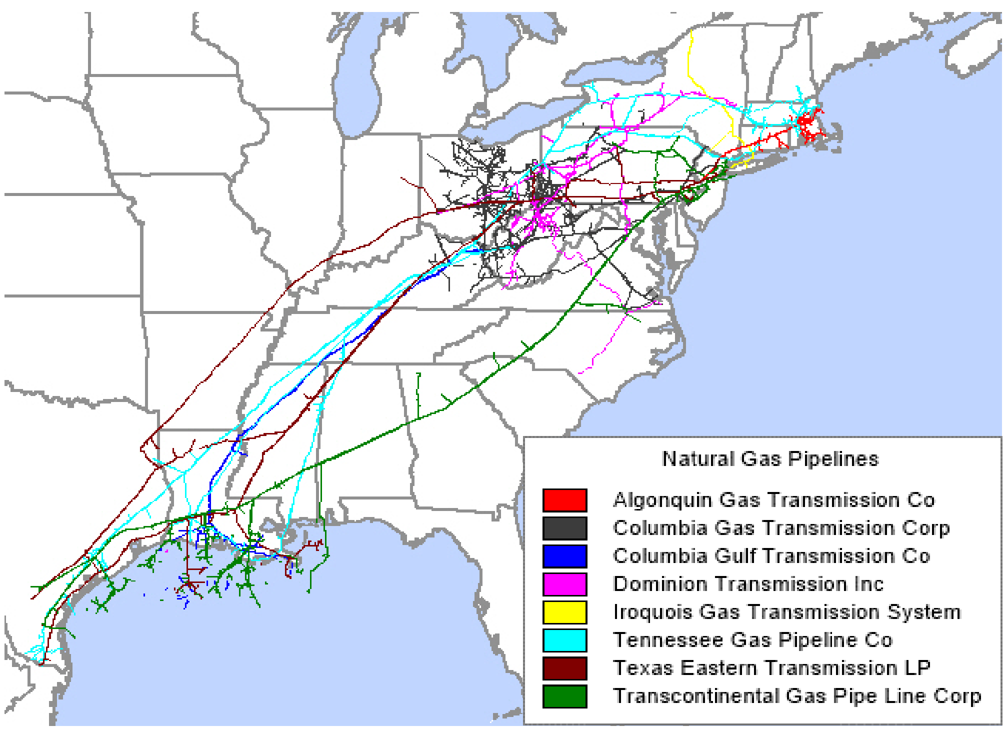
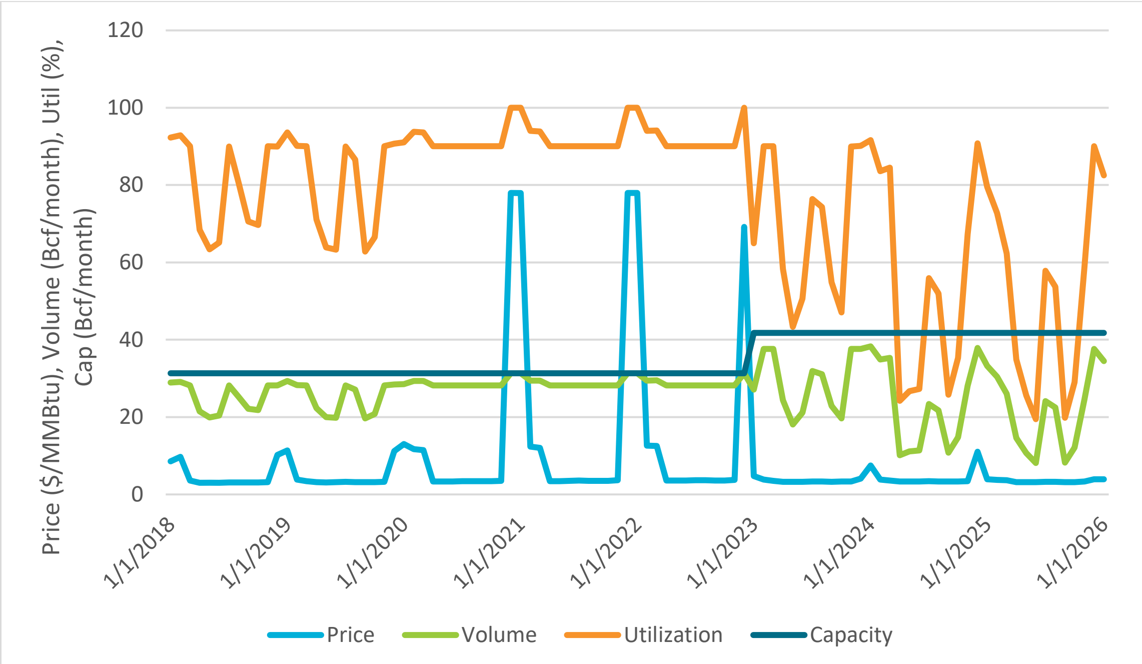


Exhibit 3-5 shows the Enbridge Algonquin Gas Transmission pipeline (AGTP) transporting natural gas from New Jersey to Massachusetts with an interconnection point in Connecticut. Gas transported from New Jersey and additional gas picked up in the Connecticut hub reaches north to meet demand in New England, particularly the Massachusetts area. The Massachusetts area is also served by the Tennessee Gas and Maritimes pipelines and by LNG at the Everett Terminal. Limited amounts of LNG are imported in the range of 2 to 10 Bcf per month. These volumes however, are not sufficient to completely relieve any supply constraint during the peak cold periods when demand rises to levels that even the incremental LNG import capacity cannot satisfy the need.

Exhibit 3-6 shows projected pipeline utilization, pipeline capacity, gas flows, and gas prices for the AGTP over the 2018–2025 period. In this graph, the results are shown from At-Risk.

Exhibit 3-5. Map of AGTP pathway in 2023

Exhibit 3-6. At-Risk Scenario: AGTP capacity additions and utilization



- The orange line in Exhibit 3-6 shows monthly average utilization percentage of AGTP that connects Pennsylvania at the Texas Eastern Transmission Pipeline (TETCO) drop off point to Rhode Island Citygate.
- The dark blue line shows the total available capacity by year (including vintage existing capacity as well as any cumulative endogenous pipeline capacity addition that the model calculated).
- The light blue line shows the monthly Rhode Island Citygate gas price.
- The green line shows the monthly volume of gas being transferred through the pipe.

In this pipeline, the pipeline utilization (orange line) varies between 60 and 100 percent in the 2018–2023 period during which the scenario assumptions did not allow any endogenous pipeline capacity expansions. During peak winter months, pipelines are being utilized fully or near fully due to increased core consumption as defined by seasonality patterns over each year. Beyond 2023, pipeline capacity expansions were permitted (considering that 4 years of planning and construction is a reasonable time for potential expansion/additions of pipeline capacity[16]). As shown in Exhibit 3-6 pipeline capacity (dark blue line) increases as the pipeline expands in 2023, and the volume that flows through the pipeline (green line) also increases during the peak months. As seasonal demand wanes during non-winter months, the volume that flows on this pipeline drops during some months as other pipelines and capacity additions take away potential volume flows on this pipeline. Consequently, overall pipeline utilization drops from the previous years' level. Further, expansion of other interstate pipelines or local laterals or

[16] Interstate pipeline permitting and construction, including expansion of existing pipelines, takes on average 38 to 46 months depending on whether the pre-filing or traditional process is utilized by the permittee and the Federal Energy Regulatory Commission (FERC). See NETL Issues in Focus – Building Interstate Natural Gas Transmission for more details. (7)

looping of pipelines within specific market regions contributes to the decrease in utilization of some of the pipelines could.

Exhibit 3-7 shows similar results for another pipeline using the At-Risk scenario—the Dominion pipeline transporting gas through the Pennsylvania production region to upstate New York, which then reaches the Northeastern markets. Exhibit 3-8 shows the schematic routing for the Dominion pipeline transporting gas from the Marcellus basin in Ohio to Upstate New York, where it interconnects with the Tennessee Gas Pipeline (TGP) and the Iroquois pipelines to meet gas demand in the Boston area.

Exhibit 3-7. At-Risk Scenario: Dominion pipeline capacity additions and utilization

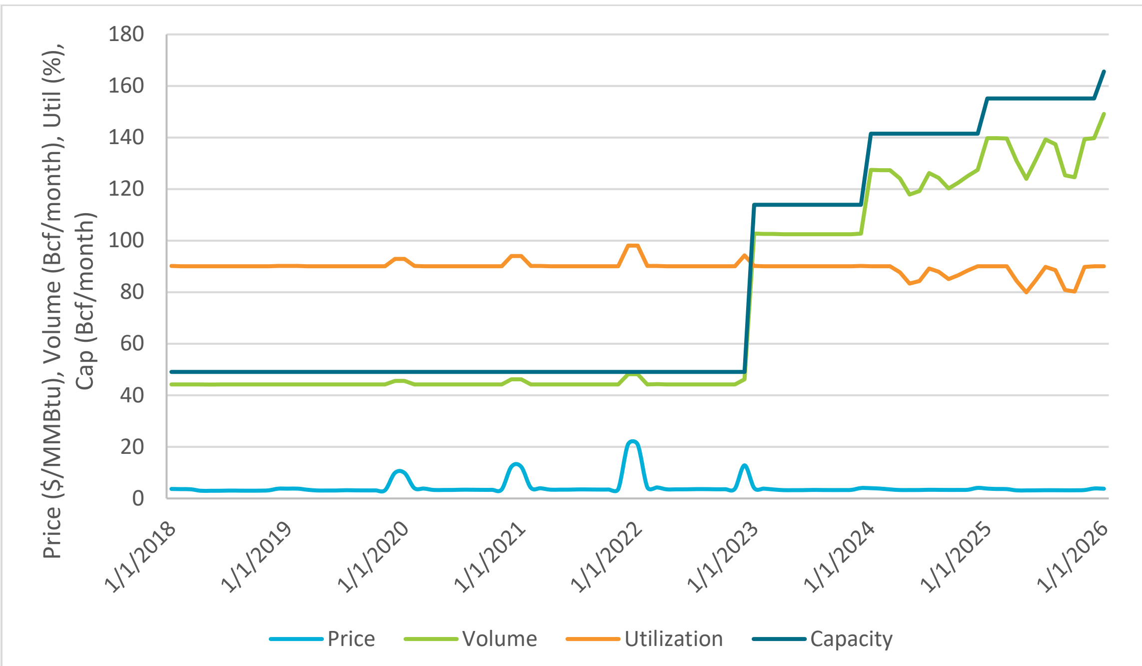


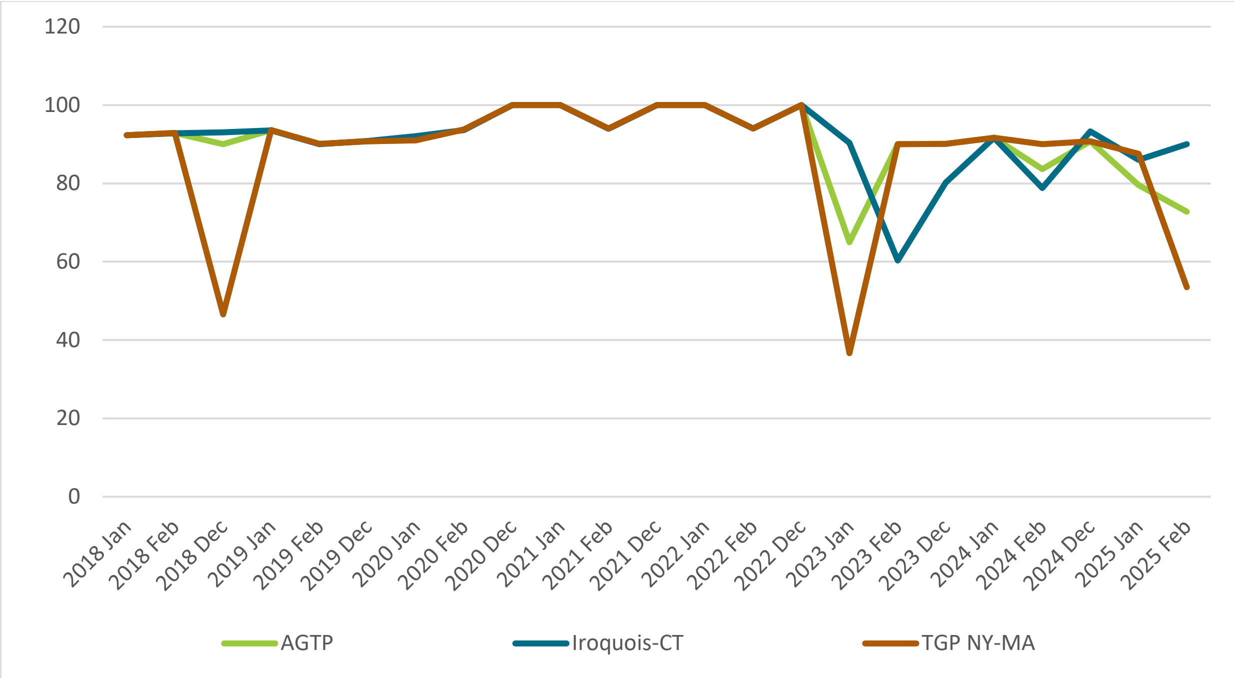
Exhibit 3-8. Dominion pipeline pathway in 2023

In this case, unlike the AGTP characteristics, the capacity utilization (orange line) remains fairly high throughout the period. Capacity is again constant until 2023, and expansion occurs over the 2023–2025 period, each year as needed. Total volume flow (green line) on the pipeline generally follows the capacity added each year. Prices in this case do not spike as high as in the AGTP case due in part to the location being away from high demand congestion corridors further east. During 2018–2023, prices rise to as high as $20/MMBtu during the peak winter months as supplies get tight and utilization of the Dominion pipeline rises close to full capacity. Post 2023, availability of pipeline capacity keeps prices steady without any spikes as seen in earlier years.

Pipeline capacity utilization depends on the total capacity and corresponding volumetric flows over time, which are dependent on the seasonality of the market that the pipeline serves. Core demand peaks in winter primarily to serve heating loads with relatively low demand during the rest of the year. Power sector demand for gas peaks in summer to serve air conditioning loads with a smaller peak in winter for lighting and some heating loads. Industrial demand does not express strong seasonality. Winter is the highest total demand period for natural gas because the core demand peak in winter is the largest seasonal swing among the sectors and the contribution of the smaller peak from power.

Exhibit 3-9 shows how winter utilization trends on some selected pipelines are projected to vary over time.

Exhibit 3-9. Winter utilization on selected pipelines

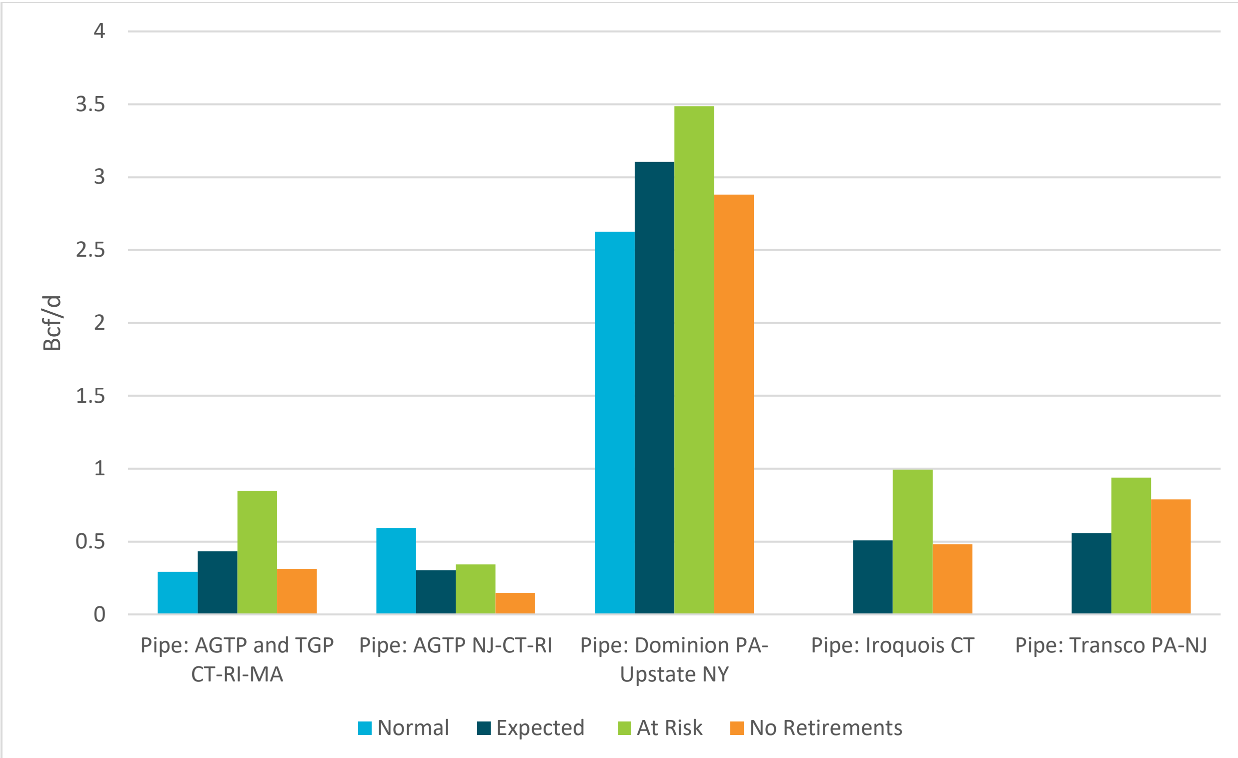


Note: this graph shows only the winter months for emphasis and is not contiguous in time

Utilization in 2023 drops as a result of new capacity being added. The utilization of the TGP section from New York to Massachusetts (TGP NY-MA), drops greater than utilization in AGTP and Iroquois because power sector gas demand in New York rises (as per the PROMOD dispatch analysis) and gas that would have otherwise flowed onward instead serve New York demand. Massachusetts demand would then be serviced by alternate routes instead of along TGP NY-MA.

Exhibit 3-10 compares the total capacity expansion and additions in each of the scenario cases over the 2023–2025 period. As per assumptions in the scenario set up, pipelines are not able to expand until 2023 unless they were already in the permitting/pre-filing/construction phase. This assumption was made since it is anticipated to take up to four years to plan, permit, and construct a new gas pipeline or expansion of an existing one. As shown in Exhibit 3-10, At-Risk, which represents the extreme conditions of retiring capacity, also shows the largest endogenous capacity additions. Further, the largest expansion is seen to occur on the pipeline taking natural gas from the Pennsylvania production regions to upstate New York (i.e., the Dominion PA-Upstate NY pipeline) from where the gas can be effectively transported to the Northeast or into Canada.

Exhibit 3-10. Pipeline segment capacity expansions or additions in the scenarios



All the pipelines shown in Exhibit 3-10 serve the Northeast region bringing gas from various supply regions.

- CT-RI-MA route segments on AGTP and TGP carry gas from pipeline interconnections in Southwestern New England to Massachusetts.
- NJ-CT-RI route segment of AGTP receives gas from the Marcellus Shale basin in Pennsylvania.
- PA-Upstate NY route segment on Dominion connects Marcellus gas to Upstate New York from where gas can be transported to New York and New England markets.
- CT route segment of Iroquois pipeline connects Marcellus and Canadian supplies to the CT-RI corridor through Upstate New York.
- PA-NJ route segment is a planned expansion on Transcontinental Gas Pipeline (Transco) connecting northeastern Pennsylvania with Transco's interconnection near Pennington, New Jersey.

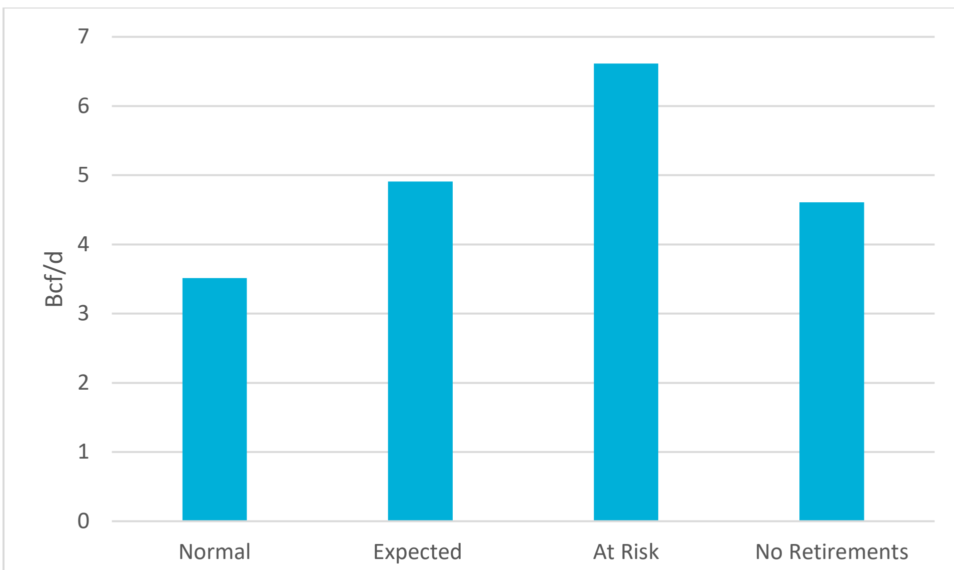
Thus, existing pipelines and potential expansions could create a network of pipelines over which Marcellus gas can be transported to critical market sectors that are currently pipeline capacity constrained.

Potential for pipelines to expand beyond the year 2023 provides a way for the Marcellus production to increase and take advantage of its economical production to meet demand in the Northeast and to also push gas to the west and south. The potential availability of pipe capacity after 2023, prompts a growth in Marcellus production by 43 percent from 2023 to 2025, in Normal and by as much as 46 percent in At-Risk. This is evident in the expansion of the Dominion PA-Upstate NY pipeline as shown in Exhibit 3-10; other routes having competitive gas prices during winter serving that region expand as well.

Exhibit 3-11 shows the total pipeline capacity expansion in the Northeast region in the 2023–2025 period, including the five major pipeline segments noted in Exhibit 3-10 along with smaller pipeline expansions not specifically discussed. The total endogenous pipeline capacity expansion is 6.6 Bcf/d in At-Risk and is almost twice that projected in Normal at 3.5 Bcf/d. At-Risk has the most coal and nuclear generation retirements and hence will have the highest gas consumption increase among the cases. No Retirements also shows more expansion than Normal as demand in No Retirements assumes the stress levels as opposed to normal demand assumption in Normal.

The Exhibit 3-11 expansion is anticipated to occur over the 2023–2025 period. The expansion of ancillary infrastructure necessary for the produced gas to be gathered, processed, and compressed into the interstate long-haul pipelines is not considered in the endogenous pipeline expansion estimates.

Exhibit 3-11. Total endogenous pipeline capacity additions



The above discussion considered only the endogenous expansion of pipeline facilities. Exhibit 3-12 and Exhibit 3-13 below illustrate the exogenous (including existing) capacity in the Northeast region and compares the exogenous capacity with potential future expansions. As shown, the exogenous capacity is about 7 Bcf/d, and Normal adds an additional 3.5 Bcf/d by 2025. Expected, At-Risk, and No Retirements each add about 4.9, 6.6, and 4.6 Bcf/d of capacity over the same period.

Exhibit 3-12. Existing and planned gas pipeline capacity and future capacity additions

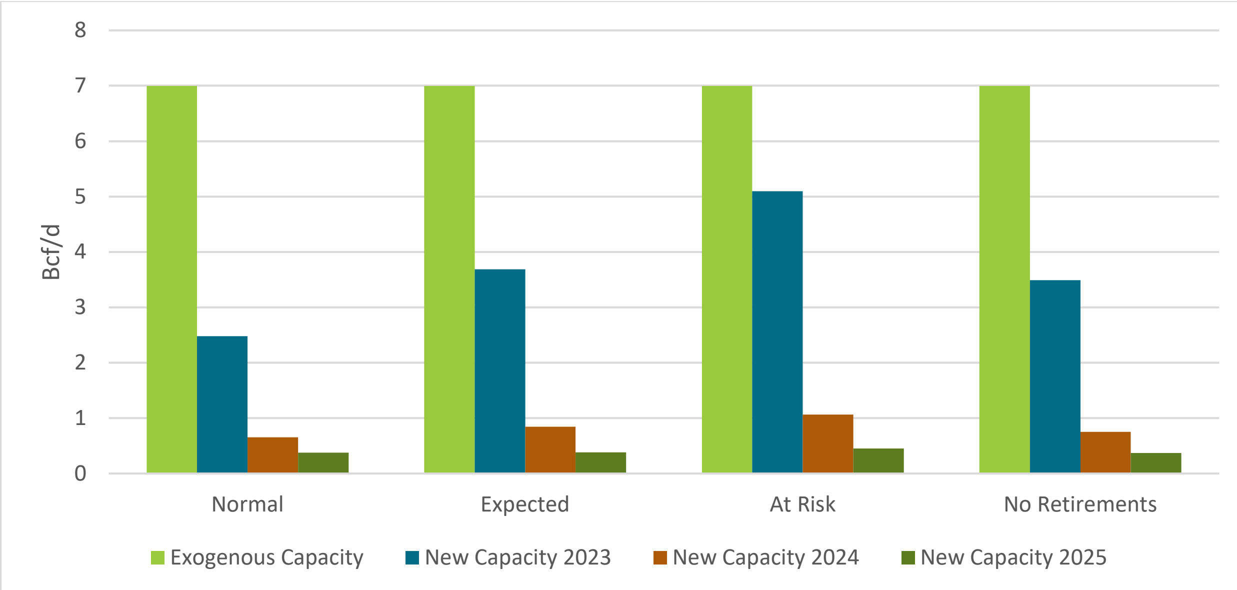


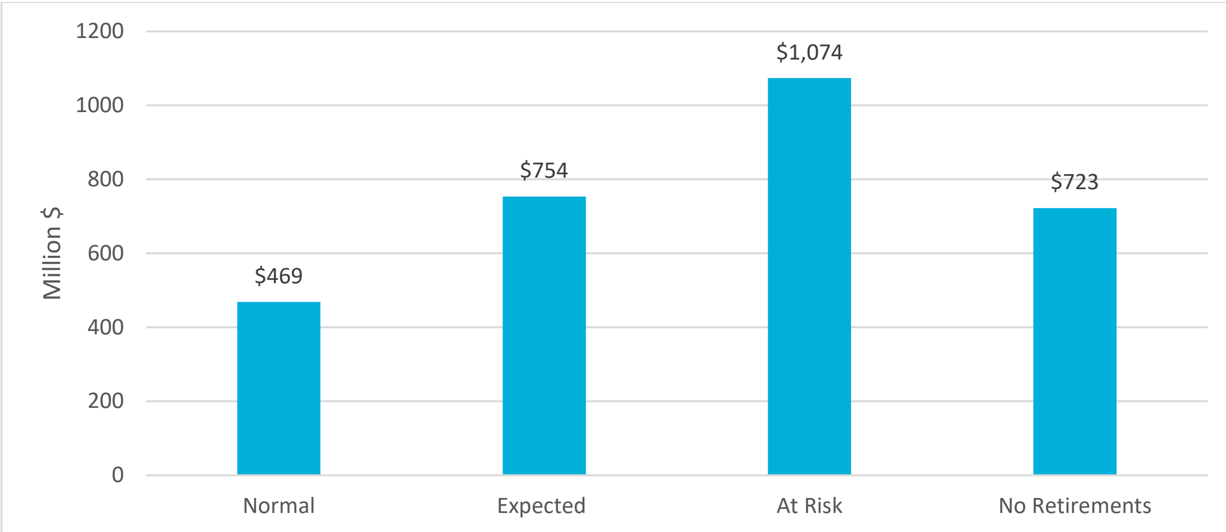
Exhibit 3-13. Total natural gas pipeline capacity additions 2018 through 2025

Scenarios	Totals
Normal	10.5 Bcf/d
Expected	11.9 Bcf/d
At-Risk	13.6 Bcf/d
No Retirements	11.6 Bcf/d

The 90/10 winter weather that was designed in the scenarios creates a rational expectation for an impending pipeline expansion at some future point. Keeping this in context, modeling assumed that such an expansion may not happen until 2023, given the administrative process that includes approvals, budgeting, and other steps, adding to a lead time of 4–5 years. Existing pipe capacity or any future expansion that has been approved or already under construction for the 2018–2022, period is included in the exogenous capacity.

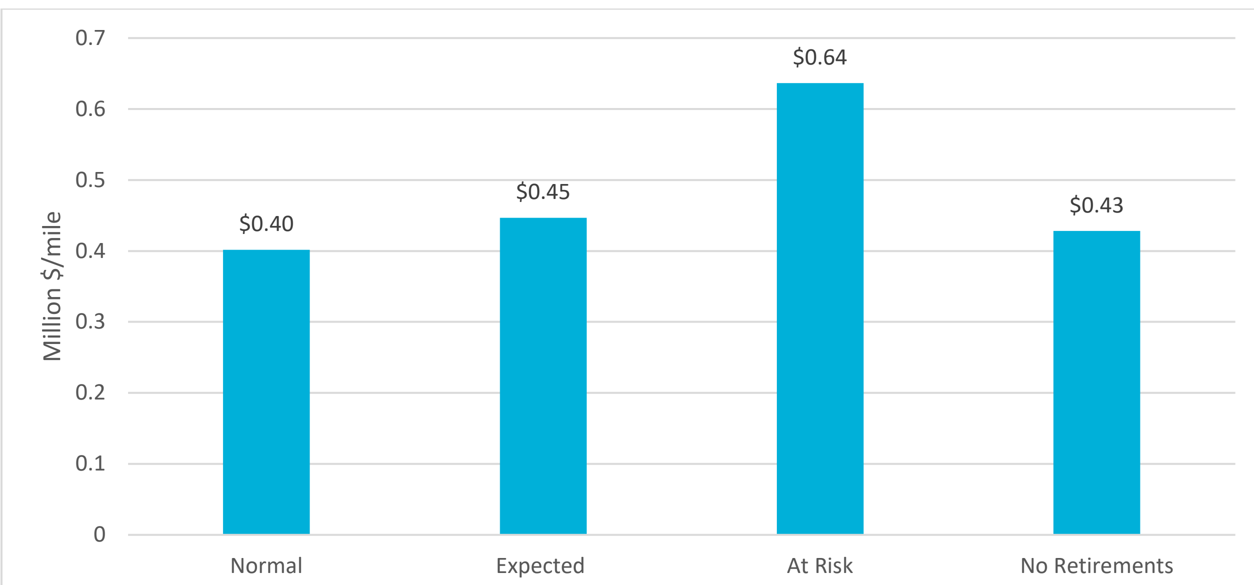
Exhibit 3-14 compares the total capital investment in pipeline expansion in each of the scenarios analyzed. The model estimates are conservative and only consider the overnight cost of expansion facilities and do not include factors such as amortization, taxes, insurance, discounts, and other financial cost details. They do not consider all projects under construction, only those within the selected corridors included in the scenarios. In At-Risk, the overnight expansion costs amount to $1.1 billion compared with a cost of about $470 million in Normal. This study also did not include any impacts of tariffs on steel and other imported material on the overall cost estimates for construction and operation of facilities over the future.

Exhibit 3-14. Capital expenditures based on endogenous expansion of pipelines



The total investment per mile of pipeline capacity is shown in Exhibit 3-15 below.

Exhibit 3-15. Total investment per mile of new pipeline capacity



The investment cost per mile is the total investment over the 2023–2025 period on endogenous pipe capacity expansions. The costs shown here are before taxes, amortization, discount, and other financial additions. Also, these costs do not include the regulatory components incurred in permitting and siting and environmental approval costs, causing these estimates to be lower than estimates observed in the literature (with costs ranging between $2–7 million per mile). Further, this analysis combines expansions with new builds resulting in an average cost that would be lower than other observed/reported costs for new projects.

While the endogenous pipe capacity addition varies between cases, the pipelines expanding are the same among all three stress cases. Different new capacity cost per mile suggests different pipe diameter among cases.[17] The rate of cost of construction per mile is assumed to be same irrespective of the pipe construction specification variations.

3.3 Gas Pipeline Implications

Exhibit 3-16 shows natural gas prices at the Dracut Hub that are currently influenced by pipeline constraints. In Normal, winter peak demand raises prices in the early years up to 2023 when no expansion can occur to provide price relief. With expansions occurring post 2023, the price stress is reduced as evidenced in the chart. In all cases and across the time horizon, gas prices in winter months are at least double or more over non-winter months.

Winter price spikes in At-Risk are the most severe of the scenarios analyzed because the prices are anticipated to be significantly impacted due to high demand and insufficient pipeline supply without any new capacity expansions until 2023. However, as pipes begin to expand from 2023, the price impacts are reduced due to increased capacity to transport the gas to the Northeast demand centers.

Exhibit 3-16. Dracut monthly gas prices

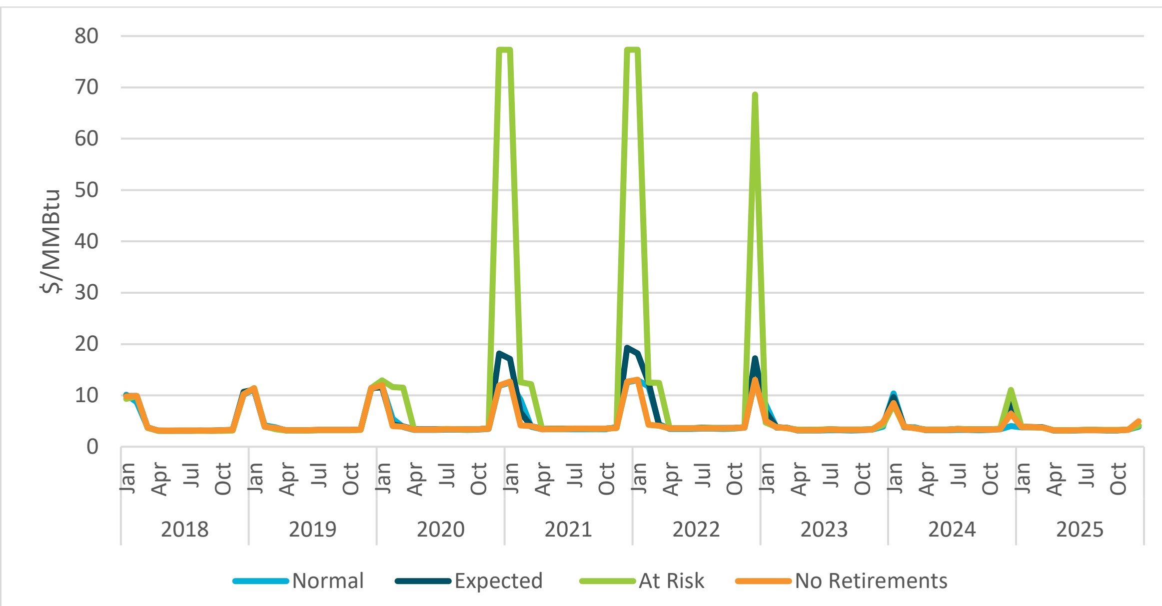
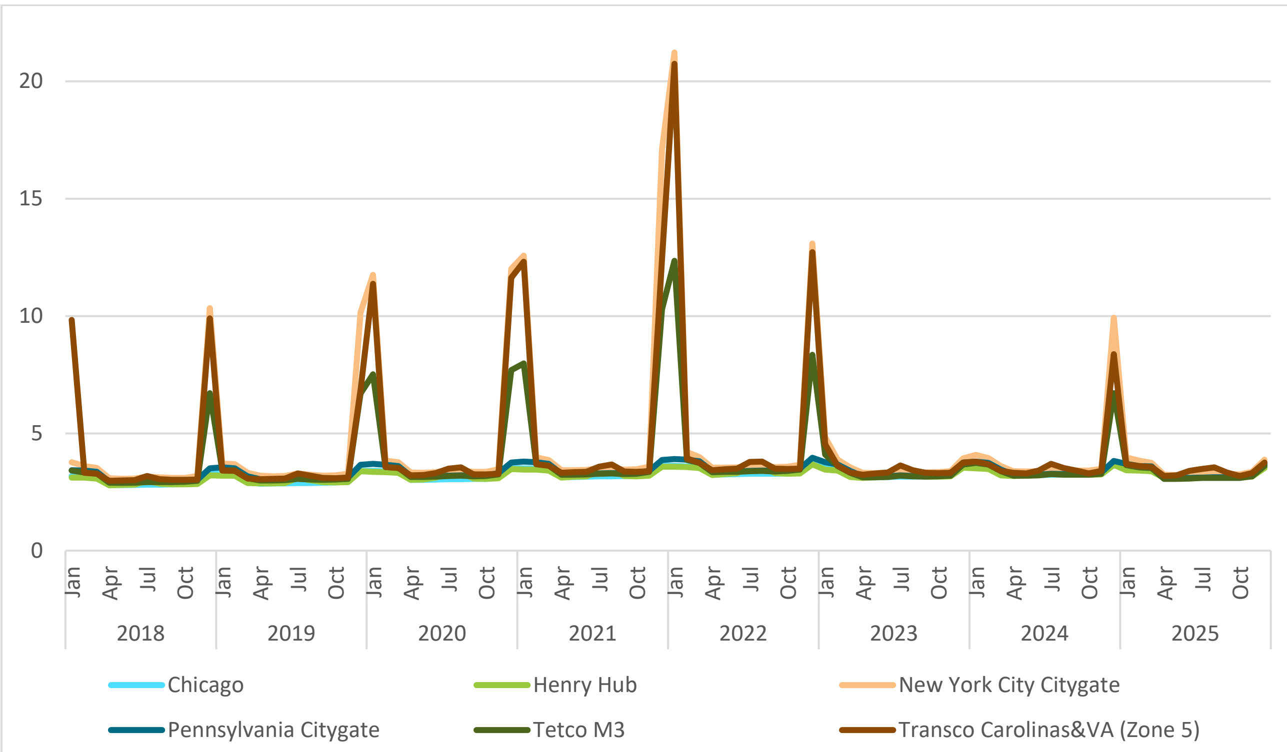


Exhibit 3-16 compares the price at a single hub across multiple scenarios with varying gas load created due to varying retirement assumptions. However, Exhibit 3-167 compares the prices at multiple hubs across the Northeastern region for the At-Risk scenario, indicating how different hubs respond to gas transport constraints. Exhibit 3-17 shows gas prices at a variety of other

[17] Natural gas pipeline construction costs vary greatly depending on location, length, pipe diameter and other factors and can vary over a wide range of $100,000 to 500,000 per inch-mile.

hubs that are not as dramatically impacted as the Dracut Hub. Again, until 2023, capacity constraints impact prices positively with prices spiking up to $15 to $20 during the peak winter months. As observed in At-Risk with the largest retirement assumptions, winter month prices increase by a factor of 3 to 7 times through 2023, before receding to 2 to 3 times in future winter months in the Northeast gas hubs as compared to Henry Hub prices. Price spikes begin to recede post 2023 as capacity expansions provide the required pathway for gas to reach demand centers. However, during winter months higher prices in years 2023 and beyond imply a continued constraint for gas supplies, but at a lower level than pre-expansion years.

Exhibit 3-17. At-Risk Scenario: Monthly gas prices at various hubs



3.4 Natural Gas Supply

Exhibit 3-18 shows gas production from the Marcellus shale basin. Production growth from 2018 to 2025 varies little across the scenarios, ranging from 10.5 percent in At-Risk to 10.2 percent in Normal. As expected, At-Risk has the highest growth in production over the forecast period.

Exhibit 3-18. Marcellus shale basin gas supply

Exhibit 3-19 compares the total dry gas production between the Marcellus and the remaining lower 48 states (L48). It shows the relative magnitude of Marcellus gas production and its increasing proportion of gas supply. Overall, once pipelines are allowed to endogenously expand, projections show that Marcellus production sees an immediate 26% spike from 2022 to 2023 before returning to a sub-10% annual average in response to the opening of the Northeastern market.

Exhibit 3-19. Normal Scenario: gas production for the Marcellus and remaining L48

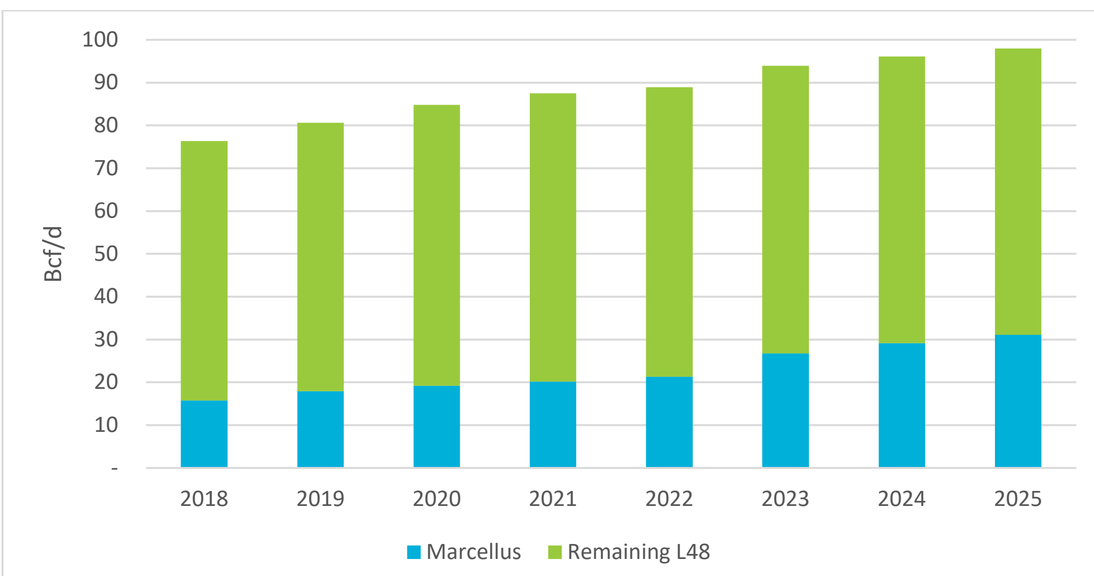
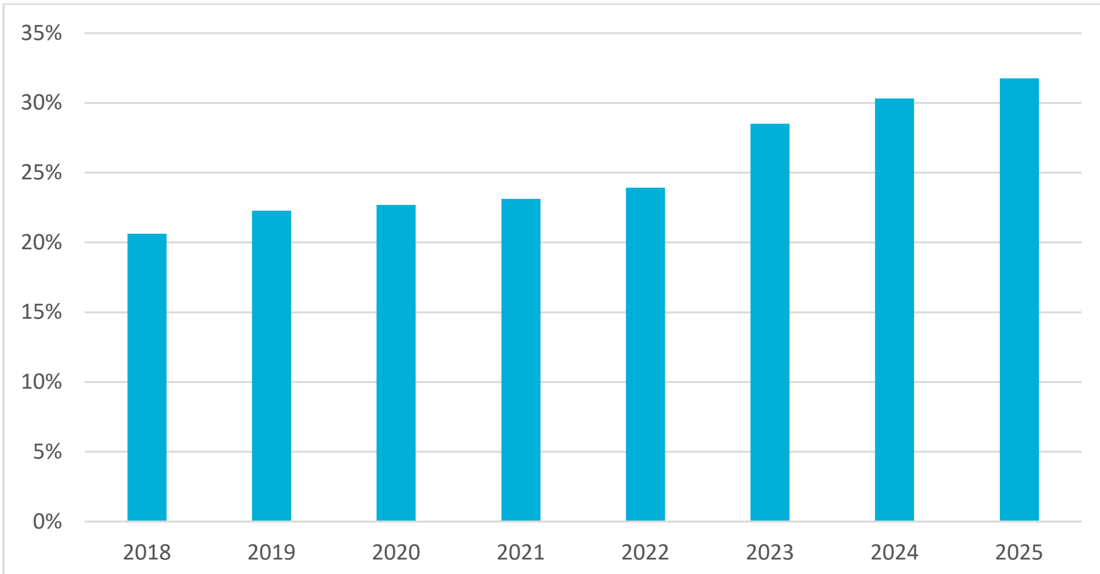


Exhibit 3-20 shows that the Northeastern states (that includes the Marcellus production basin), become more self-sufficient in gas supply over time as the share of total gas production from the Marcellus increases. Overall Marcellus gas production rises from 20 percent of total L48 production to about 32 percent by 2025. This means that the transportation routes of natural gas across the country change due the proximity of this increasing supply.

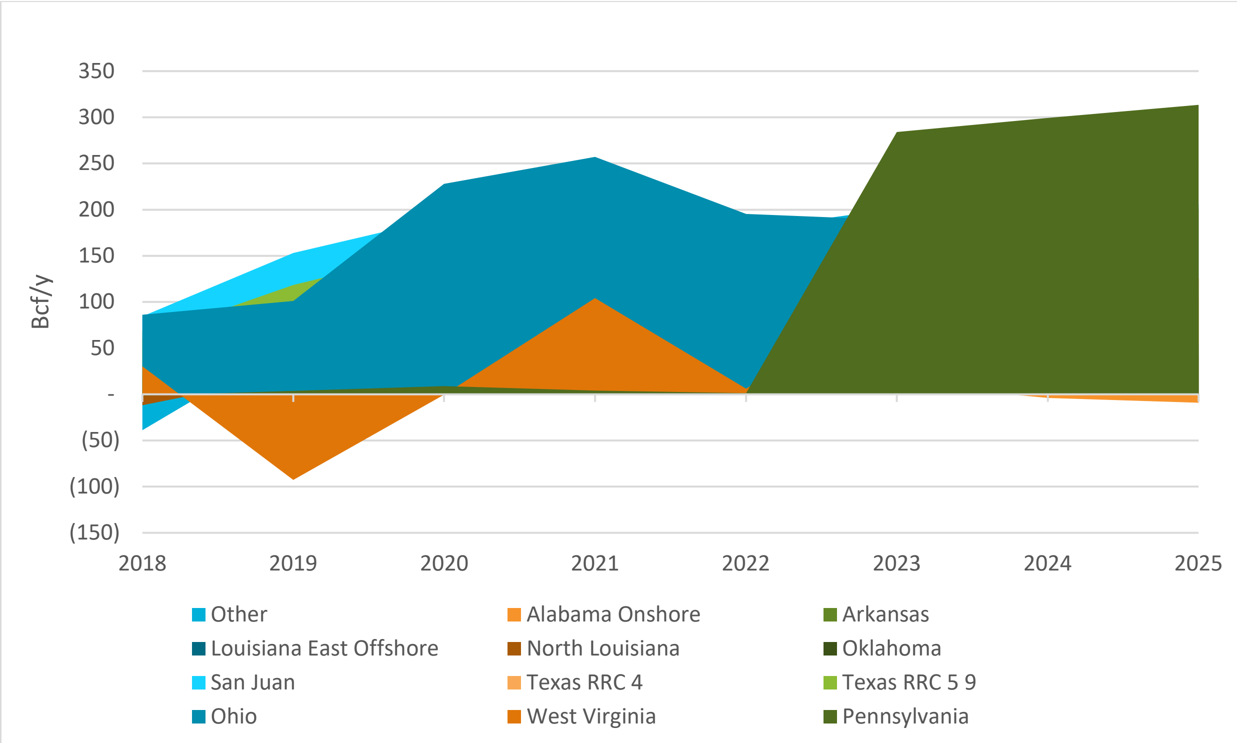
Exhibit 3-20. Normal Scenario: Marcellus percentage of total L48 gas production



Gas demand in At-Risk is higher than gas demand in Normal due to assumptions of colder winter weather and higher retirements of coal and nuclear capacity. Exhibit 3-21 shows the difference in production from various gas supply regions between At-Risk and Normal, illustrating the sources of the incremental supply to meet the higher demand.

Without any pipeline expansion before 2023, Pennsylvania is generally unable to provide incremental supply in At-Risk over Normal, whereas Ohio production increases to meet a significant portion of the higher demand. This increase also shows that Ohio has spare capacity during winter.

Exhibit 3-21. At-Risk minus Normal Scenario: Changes in the source of gas supply



Once the transportation expansions are permitted and come online in 2023, the Marcellus in Pennsylvania becomes the primary source to meet the incremental demand in At-Risk over Normal.

3.5 Power Generation

All scenarios show a drop off in coal generation and uptick in natural gas generation, as shown in Exhibit 3-22. The effect is weakest in No Retirements due to the coal generation not retiring.

Exhibit 3-22. Unit generation

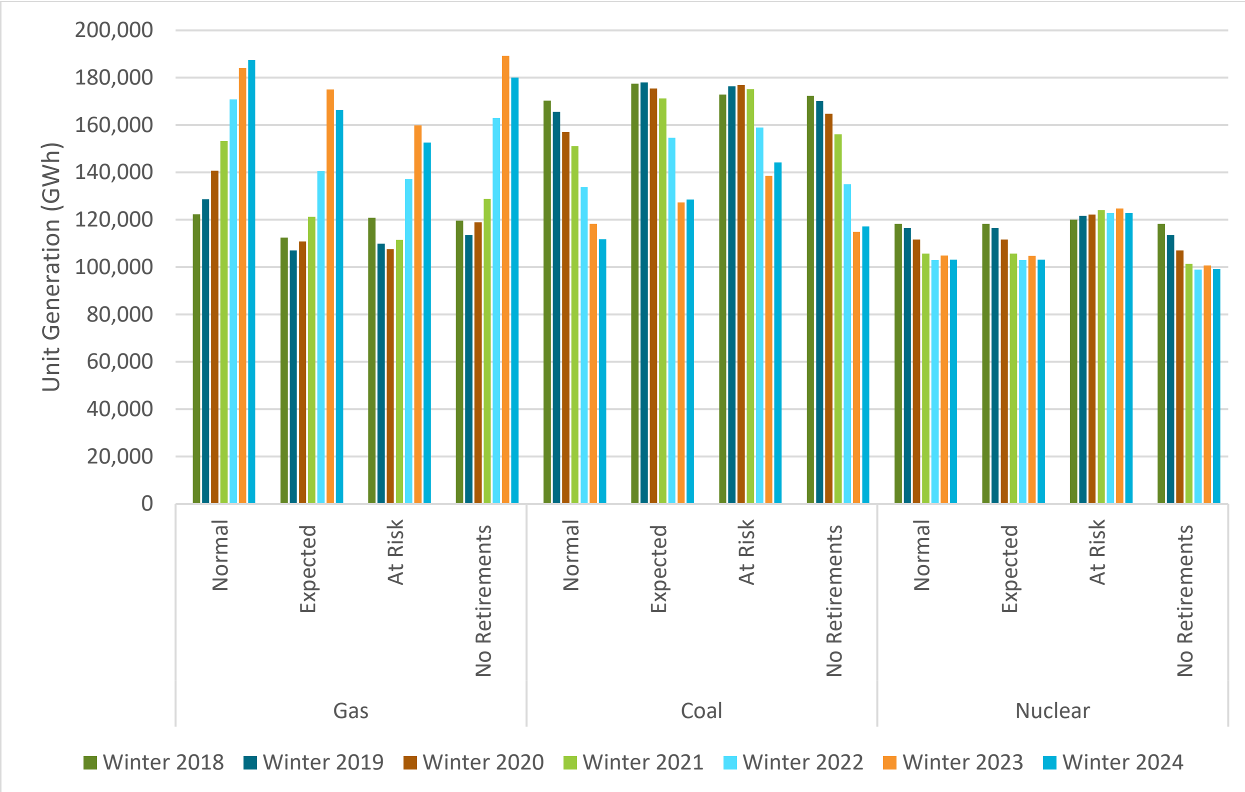


Exhibit 3-23 through Exhibit 3-26 shows average capacity factors by fuel type across scenarios for key unit types.

Exhibit 3-23. Normal Scenario: Capacity factors by fuel type (%)

	MISO				ISO-NE			
	NGCC	NG-Other	Coal	Nuclear	NGCC	NG-Other	Coal	Nuclear
Winter 2018	79.60%	18.30%	99.47%	95.36%	59.93%	5.71%	71.28%	97.87%
Winter 2019	72.82%	16.39%	93.03%	100.00%	55.02%	5.02%	71.92%	95.32%
Winter 2020	76.49%	19.47%	76.09%	94.24%	60.22%	4.38%	70.33%	95.79%
Winter 2021	81.51%	22.65%	73.75%	100.00%	63.16%	4.06%	67.05%	96.60%
Winter 2022	81.19%	21.05%	28.32%	92.37%	65.73%	5.07%	59.93%	95.63%
Winter 2023	76.23%	15.07%	3.90%	100.00%	65.61%	6.62%	55.45%	94.64%
Winter 2024	75.62%	12.13%	0.10%	92.37%	64.55%	7.88%	53.13%	95.88%
	NYISO				PJM			
	NGCC	NG-Other	Coal	Nuclear	NGCC	NG-Other	Coal	Nuclear
Winter 2018	52.43%	9.18%	55.13%	100.00%	42.74%	1.85%	69.95%	98.24%
Winter 2019	52.00%	9.67%	58.64%	100.00%	48.61%	1.85%	65.81%	98.67%
Winter 2020	50.23%	9.15%	90.54%	100.00%	46.49%	2.22%	62.80%	96.78%
Winter 2021	53.91%	9.92%	79.72%	100.00%	48.81%	2.42%	62.04%	96.71%
Winter 2022	60.66%	10.23%	59.49%	100.00%	55.97%	4.81%	56.43%	98.05%
Winter 2023	66.18%	10.27%	27.94%	100.00%	60.62%	5.54%	52.20%	98.63%
Winter 2024	67.95%	10.48%	0.00%	100.00%	62.35%	7.83%	51.19%	98.05%

Exhibit 3-24. Expected Scenario: Capacity factors by fuel type (%)

	MISO				ISO-NE			
	NGCC	NG-Other	Coal	Nuclear	NGCC	NG-Other	Coal	Nuclear
Winter 2018	47.86%	3.53%	75.22%	97.87%	52.86%	9.66%	59.97%	100.00%
Winter 2019	45.01%	4.08%	74.22%	95.32%	49.28%	9.60%	56.20%	100.00%
Winter 2020	51.64%	4.45%	71.49%	95.79%	62.22%	12.15%	0.00%	100.00%
Winter 2021	59.20%	4.41%	65.53%	96.60%	62.94%	13.45%	0.00%	100.00%
Winter 2022	60.09%	4.51%	59.90%	95.63%	65.43%	11.53%	0.00%	100.00%
Winter 2023	58.21%	4.24%	56.68%	94.64%	63.67%	10.81%	32.57%	100.00%
Winter 2024	57.98%	6.39%	53.75%	95.88%	62.39%	10.06%	0.13%	100.00%
	NYISO				PJM			
	NGCC	NG-Other	Coal	Nuclear	NGCC	NG-Other	Coal	Nuclear
Winter 2018	69.66%	26.72%	99.34%	95.36%	39.80%	2.15%	75.15%	98.24%
Winter 2019	77.66%	20.81%	94.47%	100.00%	48.38%	1.70%	69.35%	98.67%
Winter 2020	75.32%	12.20%	72.88%	94.24%	49.41%	1.95%	65.78%	96.78%
Winter 2021	82.44%	13.90%	32.20%	100.00%	53.48%	3.00%	62.35%	96.72%
Winter 2022	83.07%	17.27%	21.24%	92.37%	57.19%	4.15%	60.05%	98.05%
Winter 2023	81.91%	13.87%	20.45%	100.00%	48.92%	7.14%	65.51%	98.63%
Winter 2024	84.25%	15.56%	13.61%	92.37%	63.07%	7.31%	56.57%	98.05%

Exhibit 3-25. At-Risk Scenario: Capacity factors by fuel type (%)

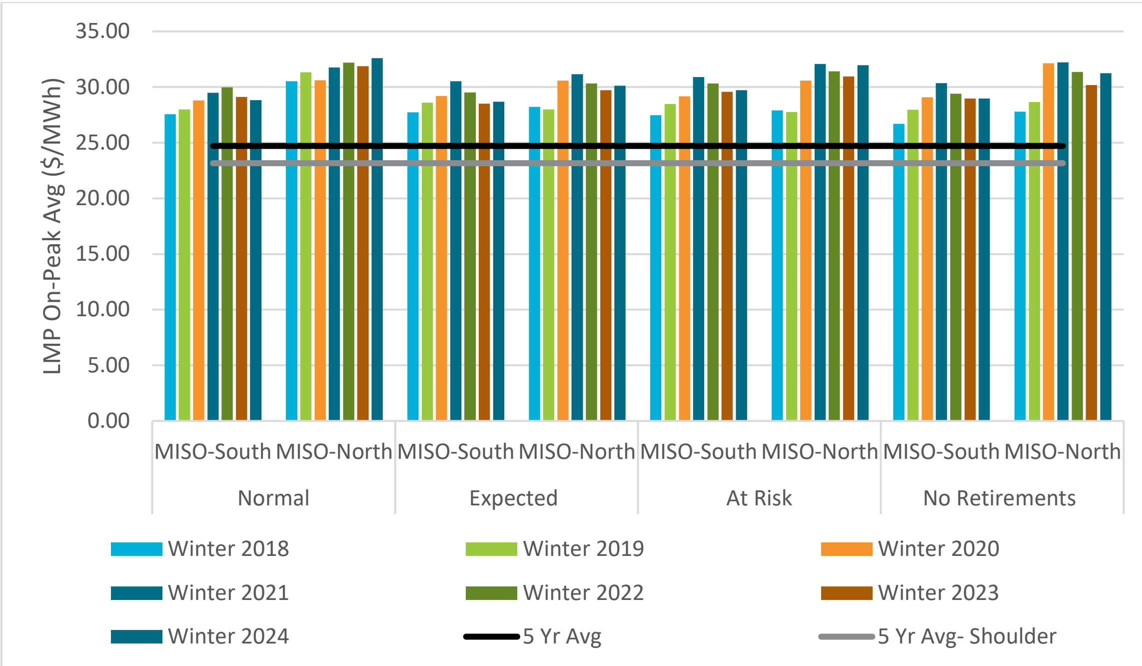
	MISO				ISO-NE			
	NGCC	NG-Other	Coal	Nuclear	NGCC	NG-Other	Coal	Nuclear
Winter 2018	54.87%	3.59%	71.33%	97.87%	46.04%	9.66%	49.49%	100.00%
Winter 2019	49.96%	3.65%	71.20%	95.32%	48.73%	9.35%	80.64%	79.72%
Winter 2020	56.18%	5.22%	74.07%	95.79%	31.48%	9.18%	98.72%	100.00%
Winter 2021	59.55%	5.04%	71.98%	96.60%	35.03%	10.12%	34.41%	100.00%
Winter 2022	61.94%	5.92%	65.45%	95.63%	58.59%	11.93%	0.00%	100.00%
Winter 2023	61.12%	5.17%	61.63%	94.64%	63.81%	10.47%	0.00%	100.00%
Winter 2024	61.22%	6.90%	59.46%	95.88%	64.48%	9.95%	0.00%	100.00%
	NYISO				**PJM**			
	NGCC	**NG-Other**	**Coal**	**Nuclear**	**NGCC**	**NG-Other**	**Coal**	**Nuclear**
Winter 2018	82.12%	21.51%	99.63%	95.36%	37.09%	2.58%	75.89%	98.24%
Winter 2019	80.49%	17.35%	33.89%	100.00%	49.02%	1.86%	70.02%	98.67%
Winter 2020	87.22%	26.09%	0.00%	94.24%	50.67%	2.03%	66.05%	96.78%
Winter 2021	88.53%	27.43%	0.00%	100.00%	55.22%	3.47%	63.83%	96.76%
Winter 2022	87.06%	19.97%	0.00%	92.37%	59.36%	4.50%	68.01%	98.01%
Winter 2023	83.40%	21.28%	0.00%	100.00%	50.04%	8.22%	73.69%	98.35%
Winter 2024	83.82%	18.50%	0.00%	92.37%	64.21%	7.37%	63.49%	97.72%

Exhibit 3-26. No Retirements Scenario: Capacity factors by fuel type (%)

	MISO				ISO-NE			
	NGCC	NG-Other	Coal	Nuclear	NGCC	NG-Other	Coal	Nuclear
Winter 2018	47.07%	3.19%	73.44%	98.00%	54.30%	9.83%	60.44%	100.00%
Winter 2019	44.11%	2.93%	72.35%	95.61%	49.08%	10.01%	27.62%	100.00%
Winter 2020	50.70%	3.11%	70.94%	97.78%	50.46%	9.85%	24.93%	100.00%
Winter 2021	60.31%	4.27%	66.92%	96.97%	54.40%	11.18%	1.08%	100.00%
Winter 2022	63.07%	3.89%	66.07%	96.11%	57.79%	10.01%	0.00%	100.00%
Winter 2023	63.85%	4.01%	62.49%	95.23%	53.68%	9.83%	17.10%	100.00%
Winter 2024	64.64%	4.45%	61.55%	96.33%	51.98%	9.88%	3.95%	100.00%
	NYISO				**PJM**			
	NGCC	**NG-Other**	**Coal**	**Nuclear**	**NGCC**	**NG-Other**	**Coal**	**Nuclear**
Winter 2018	81.02%	14.65%	61.72%	95.36%	31.39%	2.64%	77.29%	98.24%
Winter 2019	76.41%	14.93%	96.23%	100.00%	46.12%	1.75%	68.50%	98.71%
Winter 2020	76.19%	14.23%	42.19%	95.36%	47.28%	2.02%	62.70%	96.94%
Winter 2021	72.69%	10.80%	35.99%	100.00%	48.52%	2.37%	58.62%	98.82%
Winter 2022	73.46%	10.40%	18.54%	95.36%	52.25%	2.90%	55.61%	98.31%
Winter 2023	72.21%	10.53%	39.39%	100.00%	45.65%	4.89%	60.10%	98.76%
Winter 2024	76.48%	14.01%	4.60%	95.36%	60.62%	5.55%	50.33%	98.32%

Weaker winter weather effects in MISO contribute to lower natural gas price spikes. The large and varied generation mix in MISO also results in less drastic locational marginal prices (LMPs) in the region for the winter periods. Exhibit 3-27 shows the resulting LMPs for the MISO region. Less severe weather and gas constraints resulted in the modeled prices being very close, allowing for slight fluctuation in how each scenario's iteration was finished.

Exhibit 3-27. MISO LMP on-peak avg ($/MWh)



The base demand forecasts, used to iterate in Normal, resulted in marginally higher gas prices in ISO-NE. This resulted in higher LMPs in Normal. High winter natural gas pricing drives higher LMPs in all three scenarios, shown in Exhibit 3-28. The additional natural gas generation in At-Risk resulted in large price spikes up to $500/MWh during the winters between 2019 and 2022. Once new pipeline capacity begins to come online in 2023, these prices go back to 2018 levels. The LMP in NYISO also shows sensitivity to the higher gas price scenarios, especially in the At-Risk case, where LMP reaches peaks of $192/MWh, as seen in Exhibit 3-29.

Exhibit 3-28. ISO-NE LMP on-peak avg ($/MWh)

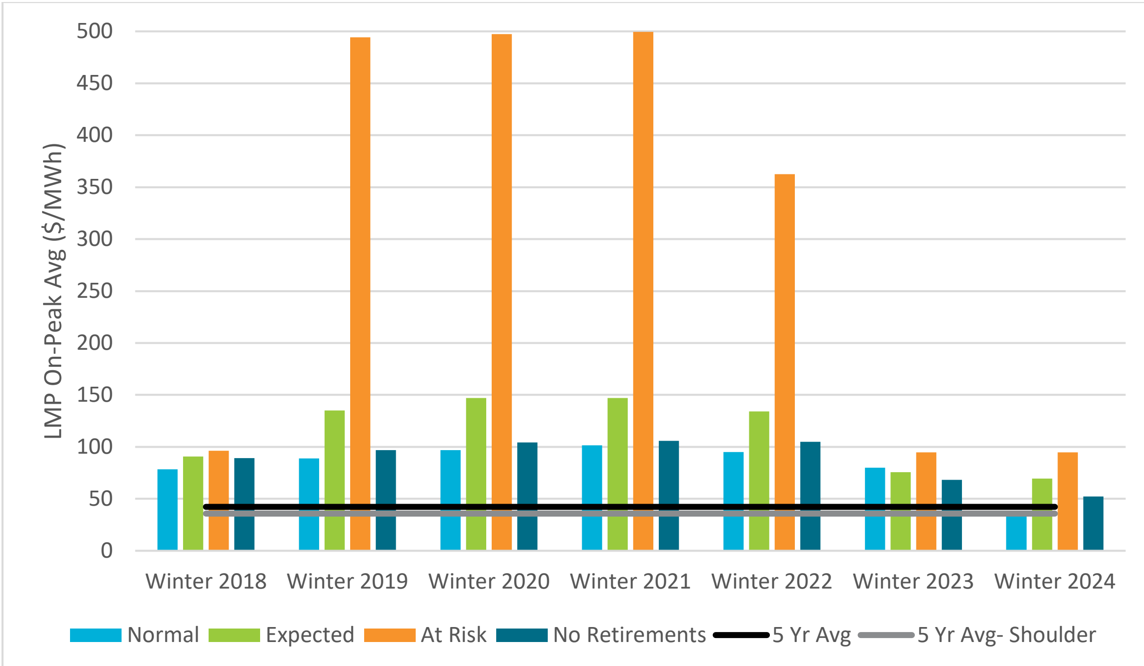
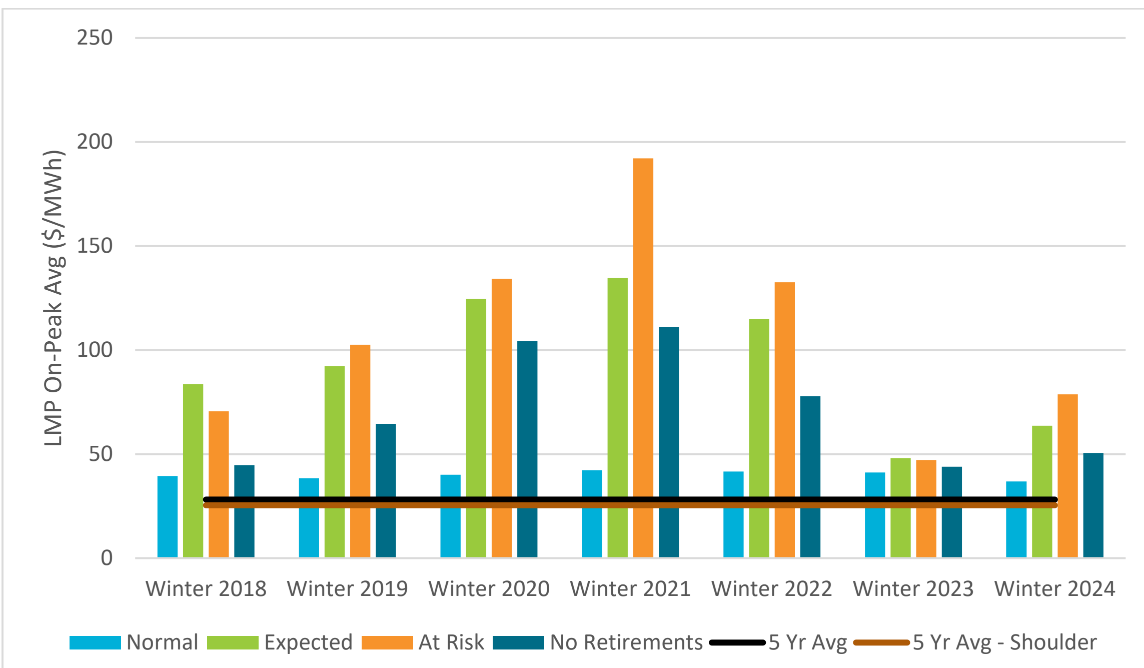


Exhibit 3-29. NYISO LMP on-peak avg ($/MWh)



LMP behavior in PJM, shown in Exhibit 3-30, is driven less by natural gas price and more by LMP price spiking due to shortage in one zone. Recent retirements and a lack of new generation being built in the Duke Energy Ohio/Kentucky (DEOK) zone in the model has led to a situation where DEOK has to rely on its neighboring zones for generation at certain times. When that neighboring generation is unable to reach DEOK, due to unavailability or transmission constraints, it causes local price spikes. Exhibit 3-31 shows the results of removing DEOK from the LMP calculation. Without DEOK, PJM shows lower LMPs, although there is still a sensitivity to the natural gas prices in all cases, with a spike in At-Risk in the winter of 2021 and 2022, calming down once more capacity is added in 2023.

Exhibit 3-33 shows a focus on just the DEOK zone. High LMP prices in this zone are driven by periods where demand exceeds the combined within zone generation and transmission import capabilities, leading to the loss of load hours shown in Exhibit 3-34. In all four RTO/ISOs, in the study, the only zone to show loss of load hours is DEOK in PJM. This is a result of retirements in the DEOK zone, and an absence of new buildout in that zone. Exhibit 3-32 shows the results from alternate model runs. These alternate model runs update the PJM model using recently released PJM data for forced outage rates for generators. The results of these updated numbers were very similar to the previous model results.

Exhibit 3-30. PJM LMP on-peak avg ($/MWh)

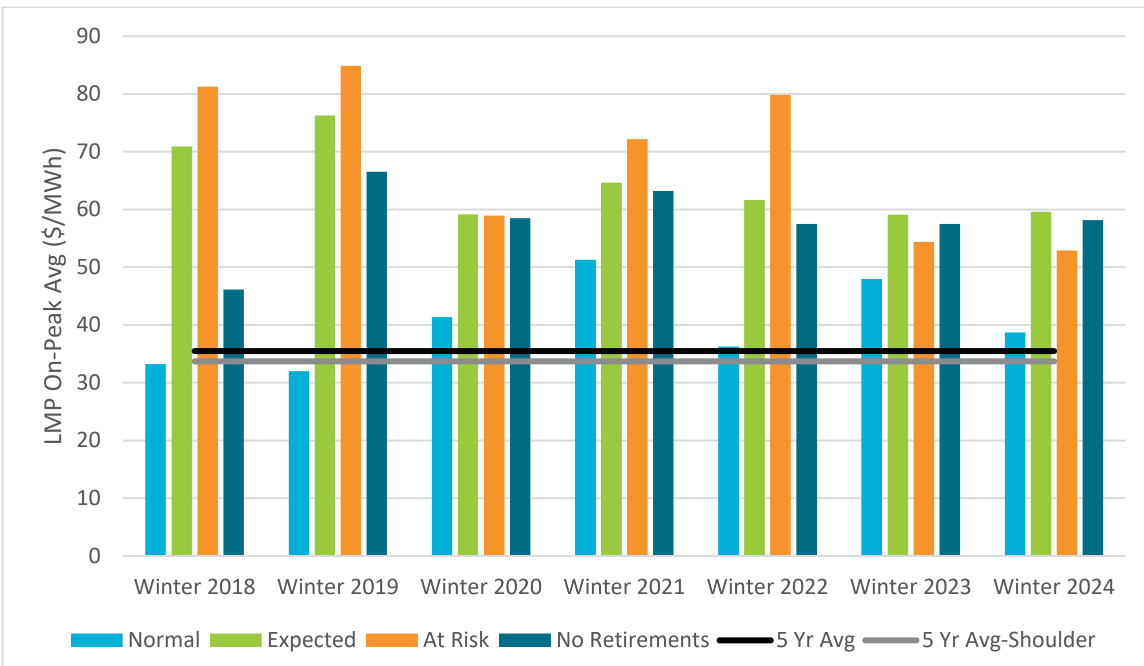


Exhibit 3-31. PJM LMP on-peak avg excluding DEOK ($/MWh)

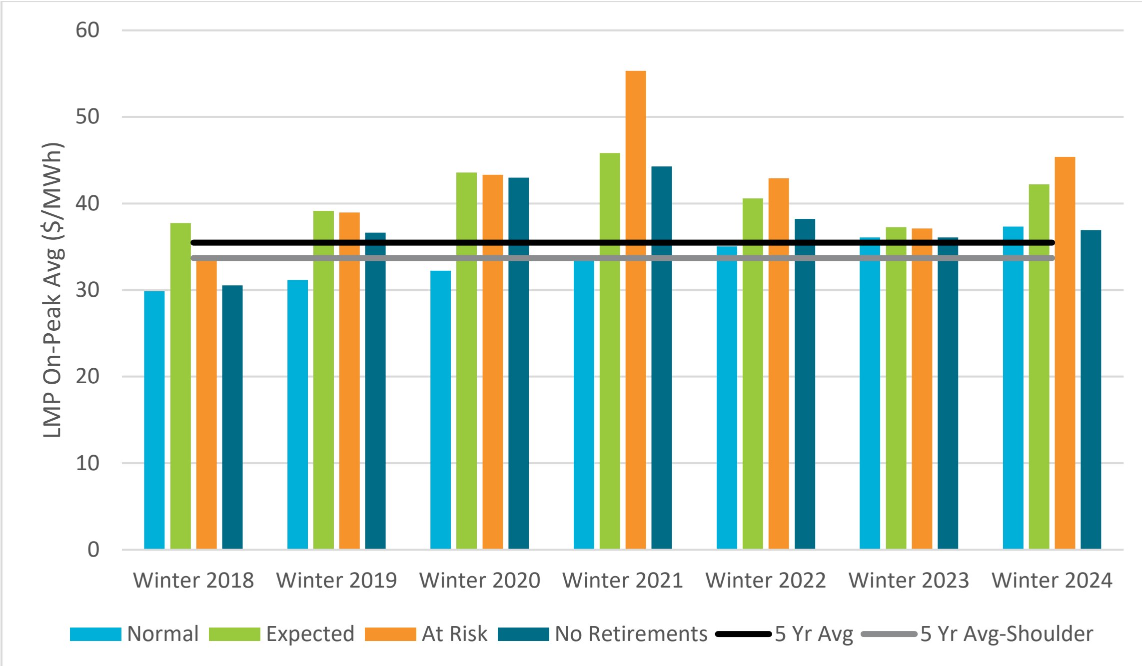


Exhibit 3-32. PJM alternate model runs excluding DEOK ($/MWh)

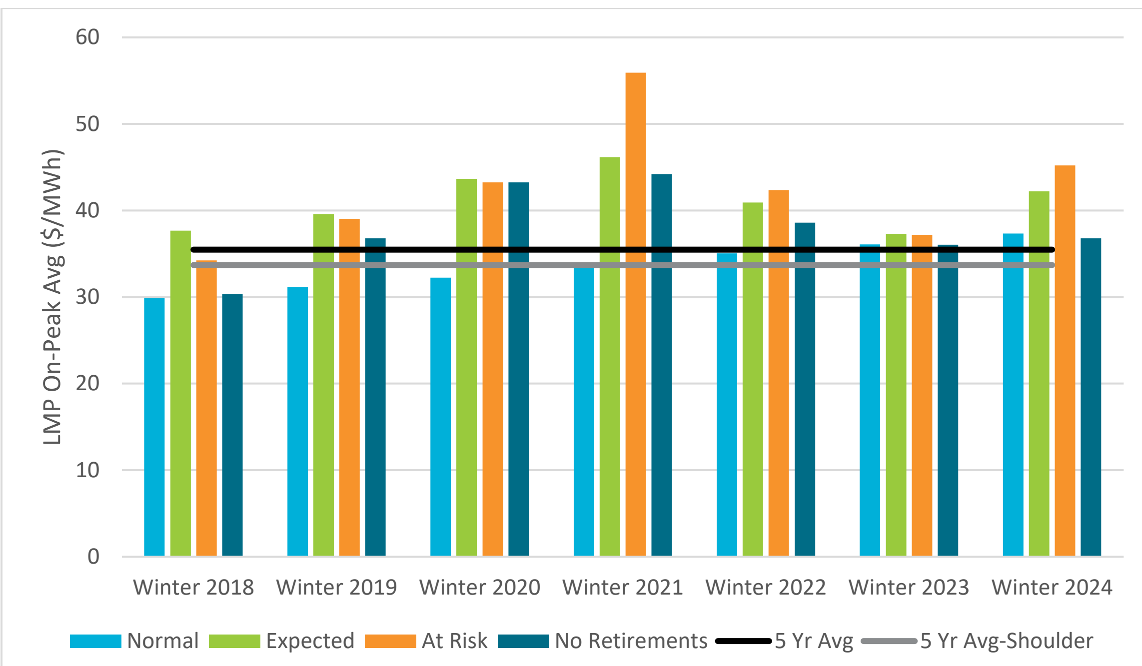


Exhibit 3-33. PJM DEOK LMP on-peak avg ($/MWh)

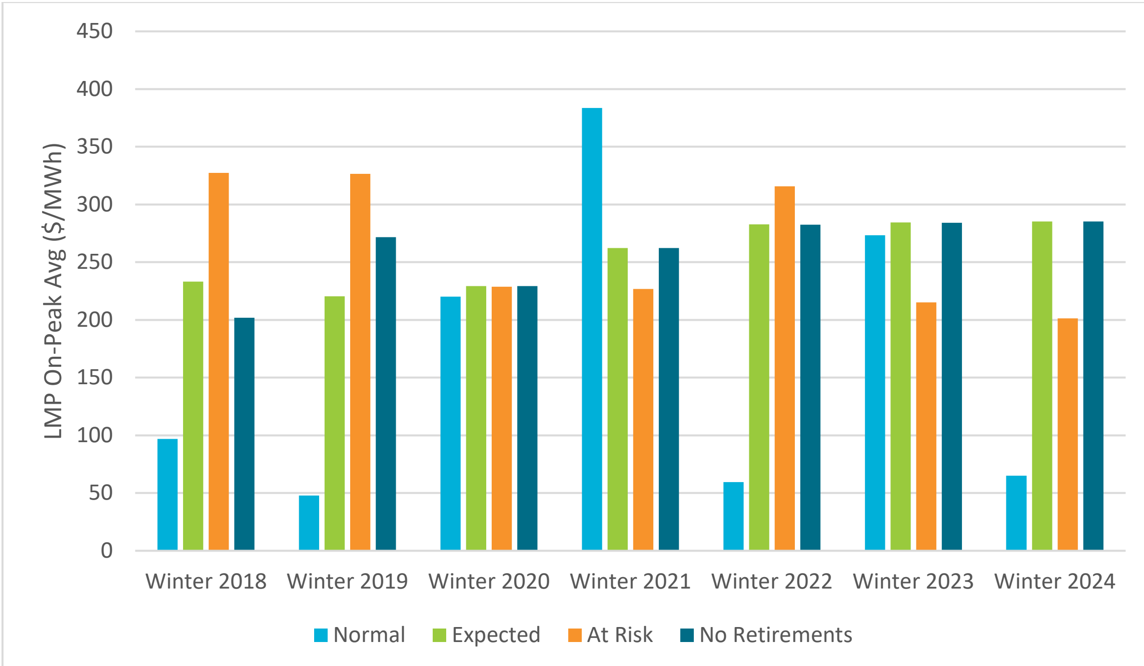


Exhibit 3-34. DEOK loss of load hours (PJM)

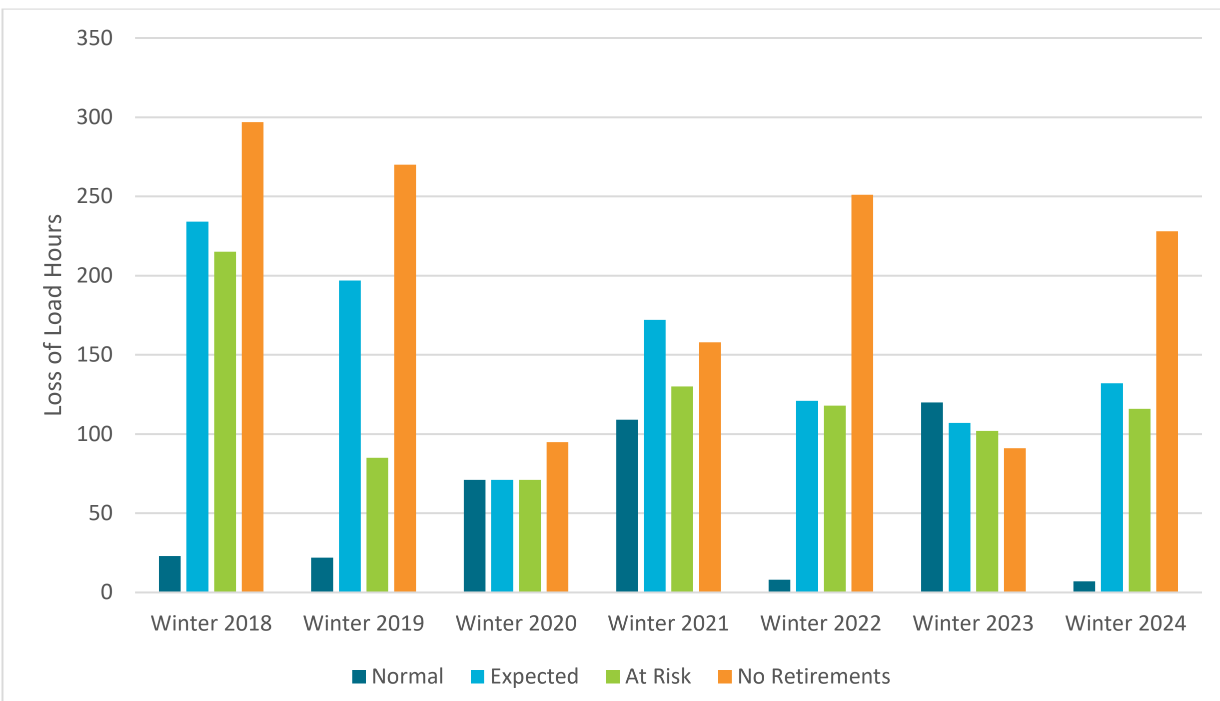


Exhibit 3-35 shows the cost of demand for each RTO/ISO and each scenario in the model. In each RTO/ISO, At-Risk shows an increase in the cost of demand over the other scenarios. These cost increases follow the trend in gas price increases, falling off after new pipeline capacity is built in 2023. ISO-NE and NYISO, the areas with the largest increases in gas pricing, show the largest increases in At-Risk.

Exhibit 3-35. Cost of demand (Million $)

	PJM				ISO-NE			
	Normal	Expected	At-Risk	No Retirements	Normal	Expected	At-Risk	No Retirements
Winter 2018	$6,661	$7,384	$7,414	$6,533	$1,771	$2,007	$1,955	$1,969
Winter 2019	$6,589	$7,792	$8,069	$7,561	$1,921	$2,226	$2,944	$2,087
Winter 2020	$7,814	$7,791	$7,889	$7,685	$2,300	$3,416	$11,019	$2,451
Winter 2021	$8,334	$8,550	$9,057	$8,275	$2,522	$4,057	$11,225	$2,578
Winter 2022	$7,492	$8,354	$8,837	$7,891	$1,879	$2,289	$4,050	$1,776
Winter 2023	$9,039	$7,874	$7,792	$7,698	$1,553	$1,608	$1,576	$1,519
Winter 2024	$7,955	$8,614	$8,461	$8,159	$1,188	$1,484	$1,762	$1,285
Total	$53,884	$56,359	$57,519	$53,802	$13,133	$17,087	$34,531	$13,665
	NYISO				MISO			
	Normal	Expected	At-Risk	No Retirements	Normal	Expected	At-Risk	No Retirements
Winter 2018	$1,267	$1,960	$1,847	$1,590	$4,981	$4,572	$4,535	$4,570
Winter 2019	$1,260	$2,546	$2,903	$1,785	$5,107	$4,668	$4,664	$4,666
Winter 2020	$1,309	$3,515	$3,781	$2,933	$5,362	$4,928	$5,016	$4,937
Winter 2021	$1,367	$3,971	$5,391	$3,114	$5,550	$5,152	$5,186	$5,199
Winter 2022	$1,315	$2,539	$2,589	$1,837	$5,515	$5,168	$5,249	$5,296
Winter 2023	$1,253	$1,620	$1,593	$1,463	$5,604	$5,144	$5,236	$5,314
Winter 2024	$1,225	$1,790	$1,915	$1,556	$5,670	$5,249	$5,357	$5,425
Total	$8,997	$17,941	$20,019	$14,278	$37,789[A]	$34,881	$35,243	$35,407

[3-3A]The difference in the cost of demand in the MISO region, between the normal case and the other cases, corresponds to the LMP trends shown in Exhibit 3-27, is driven by a weaker winter demand compared to the base model forecast.

4 Conclusions

The integration of MarketBuilder and PROMOD is a way of providing a more robust look at both the natural gas and electricity markets, and the price interdependencies of those two systems. Using an iterative process to integrate two separate modeling systems allows for the systems to address the competing challenges of diurnal electrical load shapes and generation dispatch at hourly timescale with infrastructure investment economics at annual/decadal timescale. MarketBuilder provides insight into the natural gas markets in the Northeast region as they shift in response to stresses created by extreme weather, and the changes in both heating and electricity demands caused by the weather. PROMOD provides detail on the way the power grid responds to the shifting electricity demand, and gas price fluctuations experienced during extreme weather events.

Normal provides a starting point for iteration between the models in the other scenarios. Normal also sets a baseline for comparison, demonstrating how the two models interact without the stresses placed by the extreme weather events. This baseline look highlights price seasonality seen at the Dracut hub during a normal winter demand forecast. The winter price spikes can be attributed to the interaction between growing natural gas demand in the region and the limits of existing infrastructure. Fuel price spiking contributes to the ISO-NE system LMP increases seen in the Normal case. This could indicate potential future price events in regions that indicate increasing natural gas consumption over the future years.

To reflect the lead time required to finance, permit, and construct additional pipeline capacity, a modeling restriction is placed on endogenous natural gas infrastructure development until 2023. Regional pipeline utilization of 60-100 percent in the winter months was observed across a number of pipelines, particularly until the modelling permits endogenous expansion is permitted in 2023. This limiting of the potential capacity expansion can curtail gas supply to several regions and discourage demand. The high prices that result from constrained delivery reduce as elastic demands respond and generators can economically dispatch units not fired on gas. Production growth slows in the years leading up to 2023 as takeaway capacity does not increase. When the modelling simulates endogenous pipeline expansion beginning in 2023, the simulations also show natural production jumps, annual production growth increases, gas prices in demand areas moderate, and demand for gas increases. These simulated pipeline expansion benefits were reflected in simulated RTO/ISO system LMP pricing as well, showing rising prices until 2023, and return to relative normality in subsequent years.

To meet the growing demand, both in winter and in other seasons, additional pipeline capacity is necessary. Once endogenous pipeline expansion limitations are lifted, the system immediately adds capacity beginning in 2023. Total capacity expansion buildout across the system is between 3.5 Bcf/d in Normal and 6.6 Bcf/d in At-Risk. The expansion represents a capital investment of between $470 Million and $1.1 Billion.

The Northeast regions showed the most stress to the natural gas infrastructure with regional hub prices spiking above $20 in certain months. However, all four electricity market regions showed a sensitivity to the increased natural gas pricing in all three scenarios, and these sensitivities increase as more natural gas and renewables are added into the system. The effects were less pronounced farther away from the northeast, with the smallest effects among Eastern Interconnection regions felt in MISO, with price differences in ISO-NE being the largest over all.

Expected shows how each region could respond to the increased natural gas prices given the currently slated generation retirements and additions. In the event that extreme weather places increased demand and a corresponding gas price increase, the power sector could experience an increase in electricity price ranging from $2/MWh in MISO to $91/MWh in NYISO.

At-Risk takes the current trend of the loss of baseload coal and nuclear plants and magnifies that loss by including at-risk units in the retirement list. At-Risk resulted in the highest gas prices and LMPs, with increases from $3/MWh in MISO to $150/MWh in NYISO, with ISO-NE showing a $400/MWh increase over Normal.

PJM showed increased LMP over Normal in all three scenarios, with pronounced price increase in At-Risk. In At-Risk, PJM retires over 16 GW of coal and 3 GW of nuclear capacity and brings online over 35 GW of gas capacity over the horizon of the study. This shift in generation towards natural gas and away from coal and nuclear, is an underlying driver of the increased sensitivity in the region to gas prices, such as the increases experienced in At-Risk.

NYISO replaces 2.2 GW of nuclear capacity in At-Risk with natural gas capacity, and some renewables. NYISO shows a power price increase of three times the LMP versus Normal.

The cancellation of normal retirements in No Retirements results in the available resource mix of generation in each region remaining relatively stable, compared to the other scenarios. This prevents several GW of coal and nuclear capacity from being replaced with new natural gas, wind, and solar generation. As would be expected, with reduced gas exposure in No Retirements, impacts of high winter demand are less than those seen in the other scenarios.

These results show an increased need to examine interaction between natural gas and electricity markets. Competing uses (e.g., heating and electricity) for natural gas have traditionally mitigated the impacts of acute demand events with infrastructure (transport capacity) and substitution (generation redispatch to other fuels). As demand potentially outgrows infrastructure capacity and the power sector increases its reliance on natural gas as a fuel source, exposure to weather-driven demand events and associated price impacts for gas and power increases, particularly in NYISO and ISO-NE.

While this study focused on the Northeastern market region, a similar retirement of coal and nuclear generation in other regions could lead to natural gas market stress in those regions similar to that observed in the Northeast and could result in significantly higher natural gas and electricity prices throughout the Lower 48 United States.

5 REFERENCES

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7. **National Energy Technology Laboratory (NETL).** Issues In Focus - Building Interstate Natural Gas Transmission. [Online] August 25, 2016. https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=1825.

6 APPENDIX A: SCENARIO FLEET COMPARISON

This appendix contains a comparison of the changes in each generation portfolio modeled within this analysis relative to the fleet compositions reported as existing on January 1, 2019 in the 2018 NERC Long-Term Reliability Assessment. (5) Variances in capacity additions between fuel types across the scenarios are in line with the methodology described in Guideline for Developing Economic Dispatch Models for NETL Studies (3) and PJM Market Efficiency Modeling Practices (6).

Exhibit 36 Cumulative Fleet Change Comparison - MISO

	LTRA Capacity (MW)	Expected Scenario Fleet Change	At-Risk Scenario Fleet Change	No Retirements Scenario Fleet Change
Coal	57,509	-10,259 (-18%)	-15,152 (-26%)	-658 (-1.1%)
Hydro[18]	3,966	8,912 (+225%)	2,842 (+72%)	4,968 (+125%)
Natural Gas	62,265	4,643 (+7.5%)	13,813 (+22%)	4,618 (+7.4%)
Nuclear	13,025	-1,459 (-11%)	-1,459 (-11%)	—
Other[19]	3,393	-1,630 (-48%)	-152 (-4.5%)	-291 (-8.6%)
Renewables[20]	20,316	26,540 (+131%)	25,484 (+125%)	14,758 (+73%)
Grand Total	160,474	26,747 (+17%)	25,376 (+16%)	23,395 (+15%)

[18] Hydro includes all forms of hydroelectric generation, including pumped storage.

[19] Other represents capacity from petroleum, biomass, landfill gas, and other small capacity contributing generation types that are not reflected in the larger capacity categories.

[20] Renewables represents the combination of wind and solar. The values reported in the capacity tables of the LTRA reflect the regional capacity derates used in planning studies that are based upon historical performance. In market efficiency studies, the full capacity is utilized with the probability of output determined endogenously in the dispatch model. The numbers reflected in the tables in Appendix A adjust the LTRA values for these derates to reverse engineer the installed nameplate capacity values for each region.

Exhibit 37 Cumulative Fleet Change Comparison - ISO-NE

	LTRA Capacity (MW)	Expected Scenario Fleet Change	At-Risk Scenario Fleet Change	No Retirements Scenario Fleet Change
Coal	917	-466 (-51%)	-917 (-100%)	-48 (-5.2%)
Hydro[18]	1,357	-1 (neg.)	-1 (neg.)	—
Natural Gas	15,712	6,718 (+43%)	9,863 (+63%)	6,105 (+39%)
Nuclear	3,335	-684 (-21%)	-2,795 (--84%)	—
Other[19]	9,340	-1,183 (-13%)	-1,183 (-13%)	-397 (-435%)
Renewables[20]	2,433	24,903 (+1,024%)	17,914 (+736%)	9,094 (+374%)
Grand Total	33,094	29,287 (89%)	22,881 (+69%)	14,754 (+45%)

Exhibit 38 Cumulative Fleet Change Comparison - NYISO

	LTRA Capacity (MW)	Expected Scenario Fleet Change	At-Risk Scenario Fleet Change	No Retirements Scenario Fleet Change
Coal	979	-154 (-16%)	-841 (-86%)	-658 (-67%)
Hydro[18]	5,212	260 (+5%)	412 (+7.9%)	260 (+5%)
Natural Gas	16,806	1,202 (+7.2%)	-892 (-5.3%)	1,290 (+7.7%)
Nuclear	5,420	-2,077 (-38%)	-2,077 (-38%)	—
Other[19]	8,796	-1,863 (-21%)	-1,863 (-21%)	-470 (-5.3%)
Renewables[20]	2,080	820 (+39%)	1,301 (+63%)	266 (+13%)
Grand Total	39,293	-1,812 (-4.6%)	-3,960 (-10%)	688 (+1.8%)

Exhibit 39 Cumulative Fleet Change Comparison - PJM

	LTRA Capacity (MW)	Expected Scenario Fleet Change	At-Risk Scenario Fleet Change	No Retirements Scenario Fleet Change
Coal	55,136	-6,757 (-12%)	-17,347 (-31%)	-2,737 (-5%)

Hydro[18]	8,352	—	—	—
Natural Gas	76,838	18,751 (+24%)	24,532 (+32%)	19,121 (+25%)
Nuclear	32,559	-5,423 (-17%)	-3,463 (-11%)	906 (+2.8%)
Other[19]	13,781	-252 (-1.8%)	-244 (-1.8%)	-229 (-1.7%)
Renewables[20]	14,077	1,403 (+10%)	1,753 (+12%)	1,445 (+10%)
Grand Total	200,743	7,722 (+3.9%)	5,231 (+2.6%)	18,506 (+9.2%)

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