NATIONAL ENERGY TECHNOLOGY LABORATORY

RELIABILITY, RESILIENCE AND THE ONCOMING WAVE OF RETIRING BASELOAD UNITS

VOLUME I: THE CRITICAL ROLE OF THERMAL UNITS DURING EXTREME WEATHER EVENTS

March 13, 2018

DOE/NETL-2018/1883

Disclaimer

Author List:

National Energy Technology Laboratory (NETL)
Peter Balash, Ken Kern, John Brewer, Justin Adder, Christopher Nichols, Gavin Pickenpaugh, and Erik Shuster

All images in this report were created by NETL, unless otherwise noted.

The authors appreciate the comments provided by **Jarad Daniels, Angelos Kokkinos, Anhar Karimjee, and Kristin Gerdes**. Technical writing support from **Hannah Hoffman and Robert Wallace, Key Logic,** is also appreciated. Any errors remain those of the authors. As this report addresses recent events at a time of ongoing regulatory review, NETL welcomes comments from interested parties.

This page intentionally left blank.

TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

BC	Bomb Cyclone
Bcf	Billion cubic feet
Btu	British thermal unit
DOE	Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GWh/d	GigaWatt-hours per day
ISO	Independent system operators
ISO-NE	ISO New England
kWh	Kilowatt-hour
lb	Pound
MISO	Midcontinent ISO
MMBtu	Million Btu
MMcf	Million cubic feet
MW, MWe	Megawatt electric
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NYISO	New York ISO
PADD	Petroleum Administration for Defense District
PJM	PJM Interconnection
SPP	Southwest Power Pool
RTO	Regional Transmission Organization
U.S.	United States

This page intentionally left blank.

KEY TAKEAWAYS

This study examines the cold weather event now known as the "Bomb Cyclone," the winter storm accentuated by a period of deep freeze, blanketing much of the eastern half of the United States from December 27, 2017 through January 8, 2018. During the event, the Department of Energy analysis focused on five areas of organized markets administered by independent system operators (ISOs): ISO New England (ISO-NE), New York ISO (NYISO), PJM Interconnection (PJM), Midcontinent ISO (MISO), and the Southwest Power Pool (SPP). [1] Subsequently, analysis has been expanded to include the Electric Reliability Council of Texas (ERCOT). This report finds:

- Across the six ISOs, coal provided 55% of the incremental daily generation needed, or 764,000 out of 1,213,000 gigawatt-hours per day (GWh/d)
- Combined, fossil and nuclear energy plants provided 89% of electricity during peak demand across all the ISOs, with 69% coming from fossil energy plants (nearly all from traditional baseload[a] sources)
- Due to natural gas pipeline and delivery constraints, fuel oil provided almost all the surge capacity in the Northeast, barely enabling ISO-NE, in particular, to meet demand, as it experienced rapid depletion of its fuel oil storage reserves
- In PJM, the largest of the ISOs, coal provided the most resilient form of generation, due to available reserve capacity and on-site fuel availability, far exceeding all other sources (providing three times the incremental generation from natural gas and twelve times that from nuclear units); without available capacity from partially utilized coal units, PJM would have experienced shortfalls leading to interconnect-wide blackouts
- In PJM, the value of fuel-based power generation resilience during this event was estimated at $3.5 billion
- Lack of sufficient natural gas pipeline infrastructure and the surge in natural gas demand for heating led to sharp increases in natural gas spot prices exceeding 300% across the Northeast and Mid-Atlantic. The spike was particularly acute in New York with Transco Zone 6 NY spot prices rising nearly 700% from December 28 ($17.65/MMBtu) to January 5 ($140.25/MMBtu).
- Natural gas prices and availability for power resulted in units with dual-fuel capability (the ability to use different fuels) playing an important role. Fuel switching enabled units, which would have otherwise been uneconomic or taken

[a] For the sake of this report, baseload sources are defined as those that were designed for and have historically operated at above a 65% annualized capacity factor.

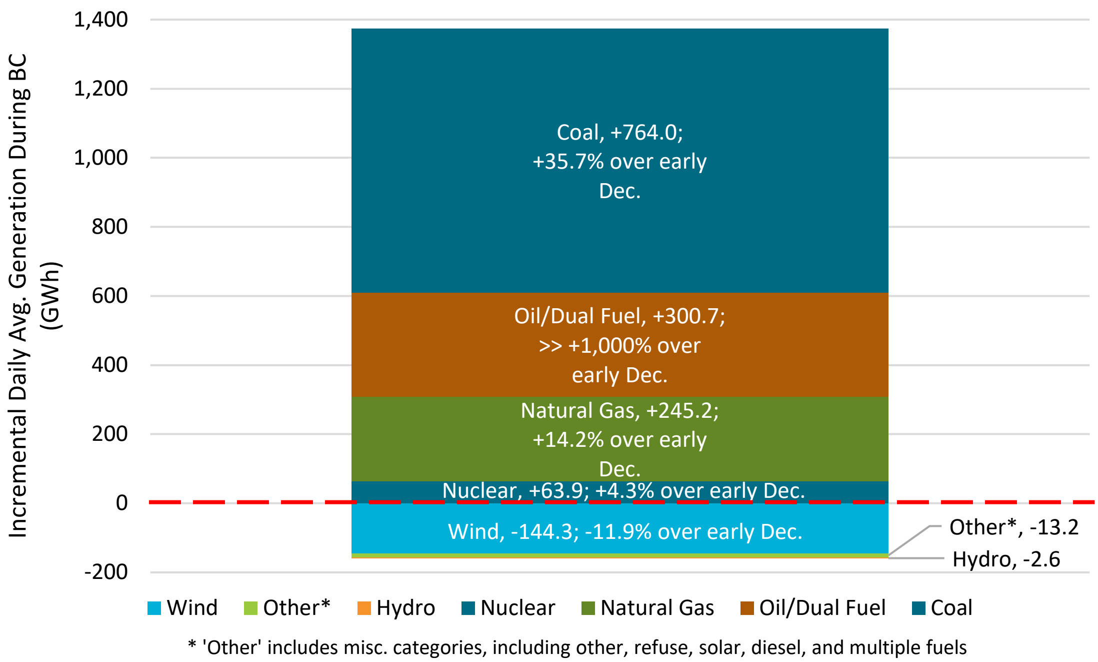
offline due to natural gas prices, to provide resilient capacity by firing fuel oil, particularly in ISO-NE where in excess of 2 million barrels of oil were burned over the 12-day period (representing more than 50% of the capacity available under the ISO's Winter Reliability Program). An estimated 60% of fuel oil in the Petroleum Administration for Defense District (PADD) I is directly imported or derived from imported crude oil

- Nuclear energy, while vital to a stable grid, generally ran at maximum output, with negligible additional capacity to bring online during this event
- Available wind energy was 12% lower during the Bomb Cyclone than for a typical winter day resulting in a need for dispatchable fossil generation to make up this generation in addition to its resiliency role in meeting the greater demand during the event
- Retirement of aging coal and nuclear generation infrastructure may be underestimated which could give rise to reliability concerns and an inability to meet projected electricity demand; however, more study is required to evaluate the impact

EXECUTIVE SUMMARY

This study examines power plant performance at elevated demand requirements during the *explosive cyclogenesis* cold weather event, now known as the "Bomb Cyclone (BC)," the winter storm that highlighted a period of deep freeze blanketing much of the eastern half of the United States from December 27, 2017, through January 8, 2018. Fossil fuels, particularly coal, responded to the system's needs during this event (Exhibit ES-1).

Exhibit ES-1. Fuel based generation resilience during the Bomb Cyclone, six ISOs



During the worst of the storm from January 5-6, 2018, actual U.S. electricity market experience demonstrated that without the resilience of coal- and fuel oil/dual-firing plants—its ability to add 24-hour baseload capacity—the eastern United States would have suffered severe electricity shortages, likely leading to widespread blackouts. Experience with such blackouts indicates the potentially enormous toll in both economic losses and human suffering associated with widespread lack of electricity, utilized as the primary home heating source for nearly 40 percent of U.S. households, and necessary for running the electric fans of natural gas furnaces, for extended periods. [2] The need for reasonable compensation to maintain resilient capacity to endure such periodically-certain threats to the nation formed the basis of the Department of Energy's (DOE) resilience compensation proposal to the Federal Energy Regulatory Commission (FERC). [3] Markets do not currently compensate resilience, and thus that capability is steadily diminishing due to competitive pressures of ongoing, baseload power plant early retirements.

FERC has initiated an analysis to define grid "resilience." and asserts in its January 8 order initiating Docket AD18-7 that "the resilience of the bulk power system will remain a priority of this commission." [4] FERC explained

> in order to appropriately study the resilience of the bulk power system in the regional transmission organization (RTO)/independent system operator (ISO) regions, we think it is appropriate to first achieve a common understanding of what resilience is in the context of the bulk power system. [4]

Though currently lacking a commonly agreed upon definition of "resilience," power plant capacity resilience can be examined during the Bomb Cyclone (hereinafter "BC") event. In this report, we examine resilience afforded by each source of power generation by assessing the incremental daily average gigawatt hours during the BC event above those of a typical winter day. Across the six RTOs in the eastern half of the United States, coal exhibited significant resilience and was responsible for 63% of the GWh increase during the BC event (Exhibit ES-1). Oil/dual fuel, natural gas, and nuclear contributed 25%, 20%, and 5%, respectively. Intermittent renewables experienced reduced overall average daily contribution to the grid during the BC event.

In the PJM Interconnection (PJM), of the three major sources of electricity generation, only coal-fired generation exhibited significant resilience in response to the extreme weather event. As shown in this report, the two major contributors to PJM giga-Watt hours (GWh) increase during the BC were coal with 74 percent of the increase and oil (partly from conversion of natural gas units) representing 22 percent. Between the two, 96 percent of the resilience in meeting the extreme BC weather event load were accomplished with all other forms of generation composing the remaining 4 percent. While contributions from other forms of generation remained flat or grew, cloud cover and wind speeds outside of operational parameters caused a reduction in average daily contribution from intermittent renewables during the BC event, essentially imparting a resilience penalty to the system. This resulted in a need for dispatchable fossil generation to make up this generation in addition to its resiliency role in meeting the greater demand during the event.

Some smaller RTOs reflect little direct reliance on coal-fired generation leading many to conclude the necessity of dispatchable thermal capacity, particularly coal-fired, no longer exists for them. However, these systems can be stretched to the limits of current capacity to endure extreme weather events, needing transfers from larger RTOs (with significant coal-fired generation, in the case of PJM for NYISO) and heavy reliance on fuel oil dual fueled units, to provide resilience and electricity supply security. The limitation of natural gas supply via pipeline for power generation in New York ISO (NYISO) and ISO New England (ISO-NE) stands out as a key takeaway from the BC event. ISO-NE, which burned over 2 million barrels of oil during the event, acknowledges that other generating fuel options must be quickly considered but indicates that added pipelines to access the abundant natural gas supply from the Marcellus/Utica region is currently out of consideration. [5]

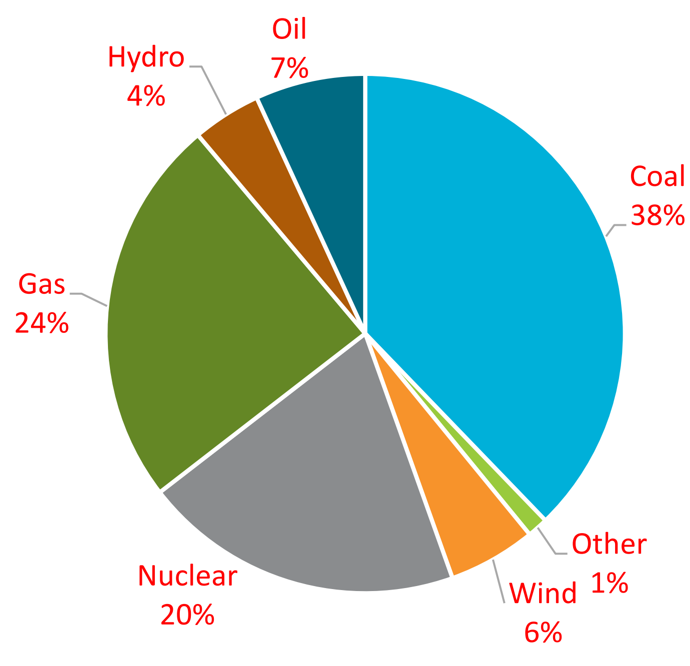
The low availability of renewables, particularly wind power, in PJM was substantially more evident in the Midcontinent ISO (MISO), Southwest Power Pool (SPP) and Electric Reliability Council of Texas (ERCOT) RTOs with declines in wind and solar output during the BC of 19 percent, 29 percent, and 32 percent, respectively.

Finally, an examination is made of planned and prospective coal and nuclear plant retirements barring compensation either for resilience value or significant and reliable baseload supply. The tendency to overestimate the ongoing contribution with age of these already mature generating assets is also considered. To the extent that electricity generation projections ignore this factor, the asset replacement scale and lead-time to maintain a diverse electricity fuel mix will be greatly underestimated.

1 THE BOMB CYCLONE

From December 27, 2017, to January 8, 2018, a cold weather event—known as the "Bomb Cyclone" (hereinafter "BC")—stressed the reliability of the affected areas, particularly the Mid-Atlantic and the Northeast. During this event, the Department of Energy asked NETL to assist in monitoring events in a five-ISO area. Periods of high electricity demand, for example January 4-6, accounted for three of the top ten winter demand days in PJM Interconnection's (PJM) history. Coal and nuclear generation, traditionally considered baseload[b], produced nearly three-fifths of the output at peak across the 5-independent system operator (ISO) footprint over the 12-day period starting December 28, 2017 (Exhibit 1-1). Prices and natural gas-fired generation output remained relatively flat in Midcontinent ISO (MISO) and Southwest Power Pool (SPP) due to plentiful gas supply, but in eastern PJM, ISO New England (ISO-NE), and New York ISO (NYISO), gas and electric transmission were severely constrained, leading to all-time high gas prices in New York and elevated natural gas and electricity prices across each region (Exhibit 1-2 and Exhibit 1-3).

Exhibit 1-1. Average peak hour generation mix, December 27, 2017 to January 8, 2018[c]



[b] For the sake of this report, baseload sources are defined as those that were designed for and have historically operated at above a 65% annualized capacity factor.

[c] Data from websites of ISO-New England, New York ISO, PJM, MISO, and SPP.

Exhibit 1-2. Regional natural gas spot prices, December 28, 2017–January 8, 2018[d]

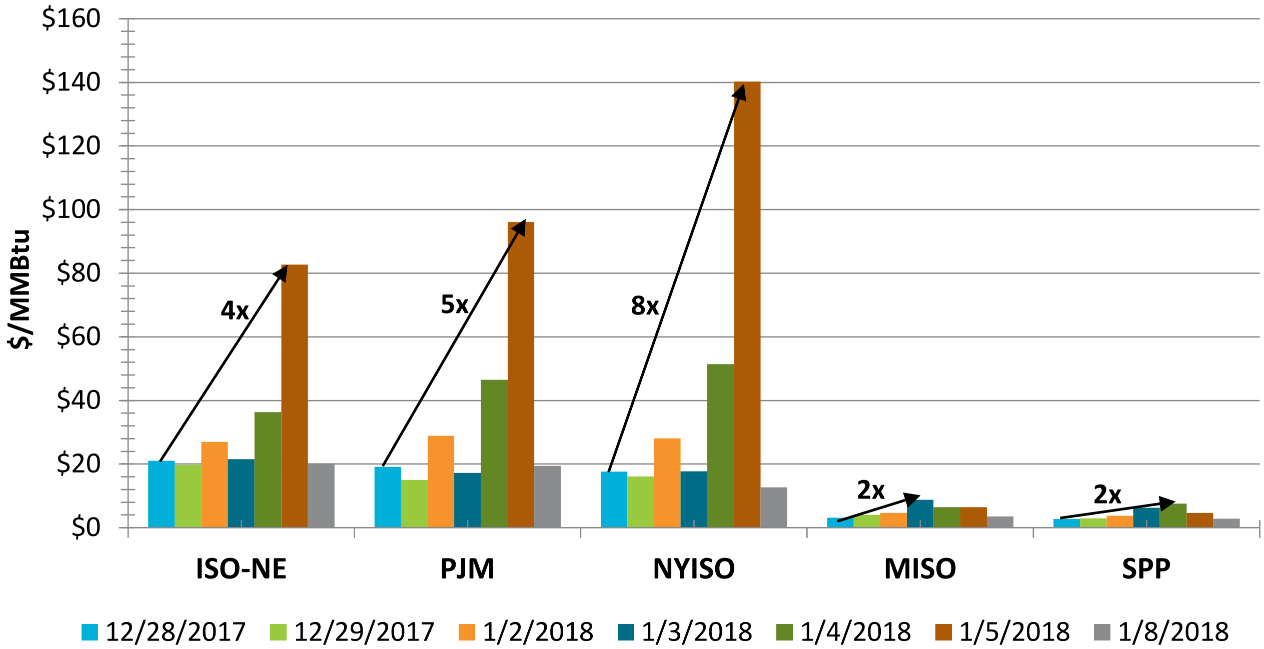
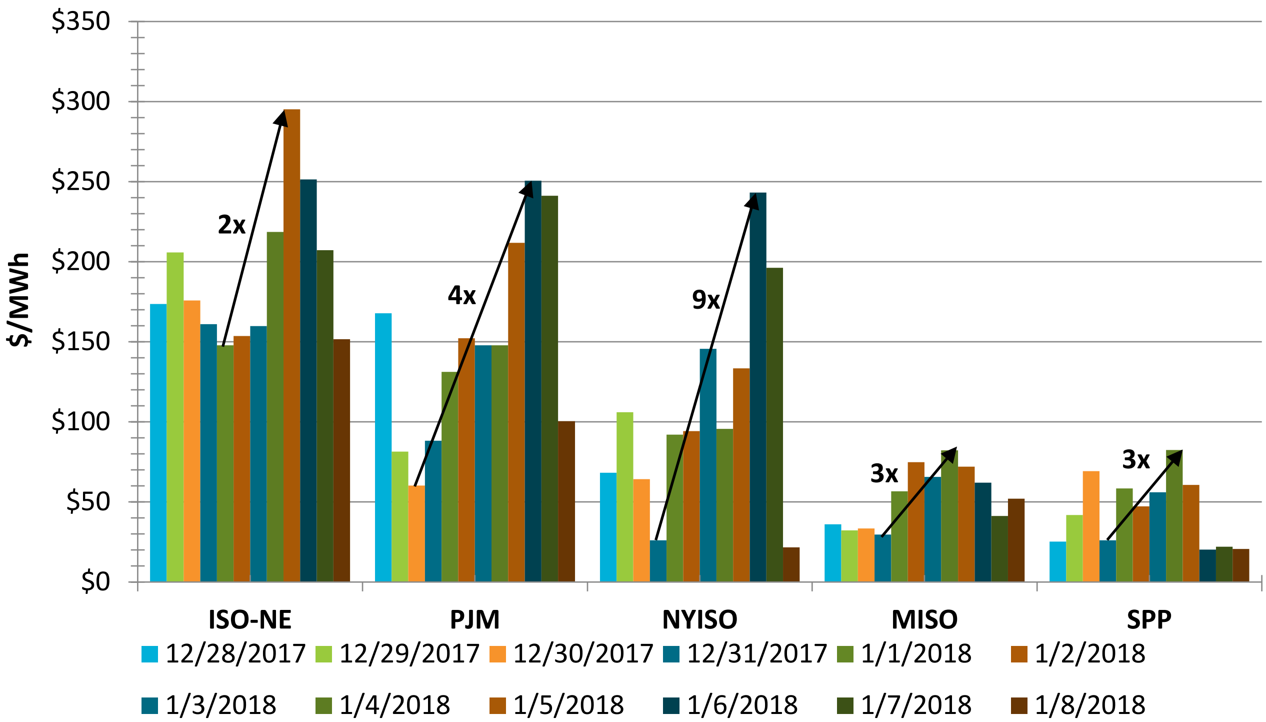


Exhibit 1-3. Daily load weighted average marginal electricity price, December 28, 2017–January 8, 2018[e]

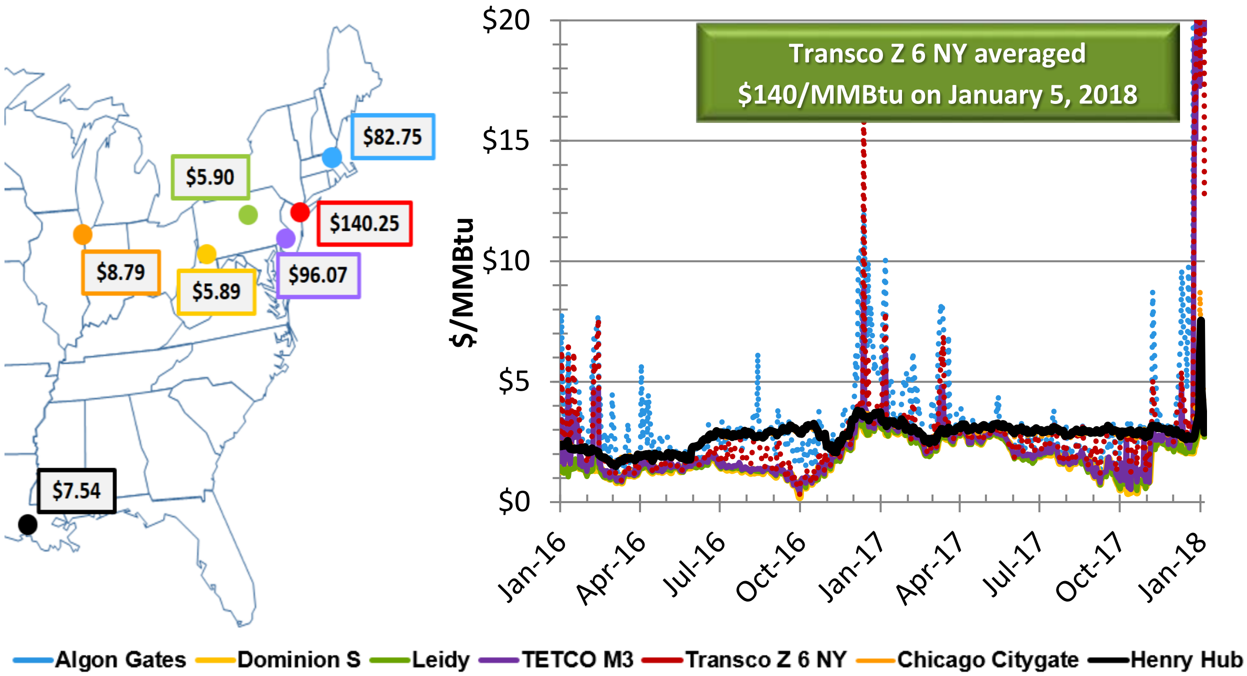


[d] Data from SNL Energy, Spot Natural Gas Prices through 1/8/2018.

[e] Data from ISO Websites.

While gas at the benchmark Henry Hub more than doubled from $3.00 to $7.00 per MMBtu, spot prices in New York reached $175/MMBtu, and averaged $140 on January 5 (Exhibit 1-2 and Exhibit 1-4). [6] Gas withdrawn from storage reached an all-time high of 359 Bcf, 25 percent higher than the previous record set for the week ending January 10, 2014. Consequently, electricity prices during this period also escalated, to be eventually borne by consumers. Compared to a mild day, three weeks earlier, coal- and oil-firing generation met the surge in demand while gas and wind generation fell (Exhibit 1-5). On average, coal capacity dispatch increased 34 GW, natural gas 2 GW, nuclear 2 GW, and gas/oil 18 GW, while wind output declined 10 GW across the five-ISO footprint. Load-weighted marginal electricity prices remained lowest in the regions with the most generation under cost of service terms (MISO and SPP, Exhibit 1-3).

Exhibit 1-4. Regional natural gas spot prices, 01/01/2016–01/08/2018 [f]



[f] Data from SNL Energy, Spot Natural Gas Prices through 1/8/2018 with January 2018 Mapped.

Exhibit 1-5. Comparison of generation, average December day vs. cold snap, 5 RTOs

Fuel	Dispatched Capacity (GW) @ Peak 12/6/2017	Contribution (%)	Average Peak Dispatch Capacity (GW) 12/28/17 to 1/8/18	Average Contribution (%)	Net Change
Coal	78.3	31.5%	112.6	37.8%	6.3%
Natural Gas	69.6	28.0%	72.5	24.3%	-3.6%
Nuclear	57.6	23.2%	59.5	20.0%	-3.2%
Hydro	11.8	4.8%	12.7	4.3%	-0.5%
Wind	26.0	10.5%	16.3	5.5%	-5.0%
Natural Gas/Oil[g]	2.7	1.1%	20.5	6.9%	5.8%
Other[h]	2.7	1.1%	3.9	1.3%	0.2%
Total	**248.8**	**100.0%**	**297.9**	**100.0%**	**0.0%**

Source: Websites of ISO-NE, PJM, NYISO, MISO, and SPP

1.1 Power Generation Resilience

In 2009, the National Infrastructure Advisory Council (NIAC) issued a report focusing on critical infrastructure resilience and adopted the following definition of resilience:

> *"Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends on its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."* [7]

Later in the report, the NAIC went on to define three additional terms that are key to examining the resilience of the power system to events like the BC: *absorptive capacity*, *adaptive capacity*, and *recoverability*.[i] Historically, resilience discussions have focused primarily on the recoverability of the system through the expediency of transmission and distribution service restoration after an event, and the ability of generating capacity to provide black start services, in the event of a system collapse. The BC, however, provides an opportunity to evaluate resilience from the perspective of the first two terms, as both the absorptive and adaptive capacities of the system, particularly from a generation perspective, to provide resilience were tested.

[g] Natural Gas/Oil includes units that are reported as oil firing or dual fueled in ISO generation reports.

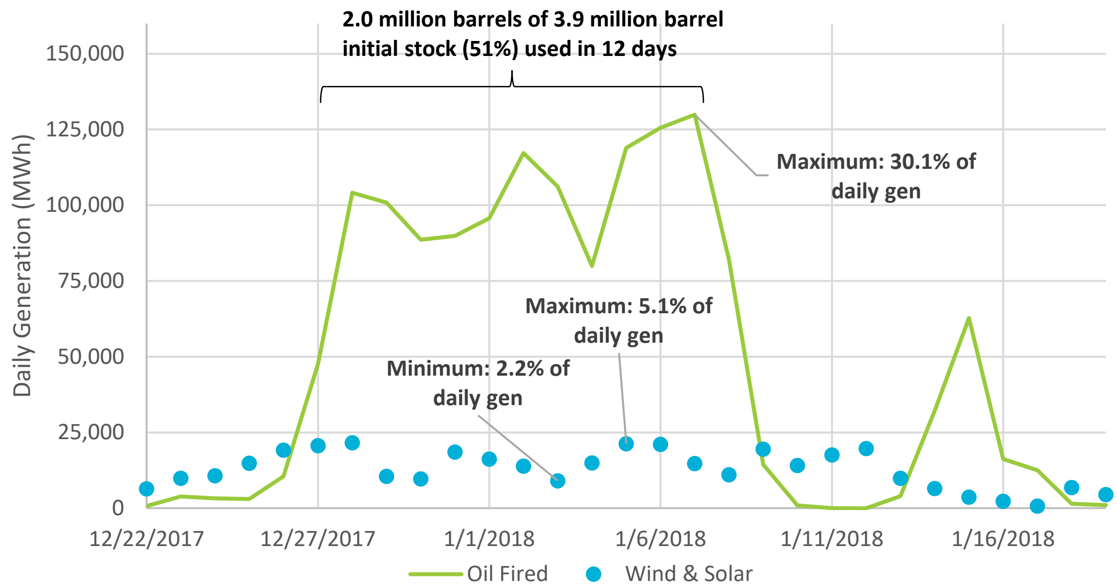
[h] Other includes units reported as 'Other,' 'Other Fossil Fuels,' and 'Other Renewables' in ISO generation reports.

[i] *Absorptive capacity* is defined as the ability to endure a disruption without significant deviation from normal operating performance; *Adaptive capacity* is defined as the ability to adapt to a shock to normal operating conditions; and *recoverability* is defined as the ability to recover quickly and at low cost from disruptive events.

1.2 New York and New England

In New England, wind and solar contributed 1-5 percent of generation at peak. In addition, over 160,000 barrels per day of oil were consumed in ISO-NE (Exhibit 1-6), and more in NYISO, due to constrained gas supply and lack of alternative, competitive generation.[j] As most fuel oil consumed in Petroleum Administration for Defense District (PADD) 1A & B is imported or derived from imported crude[k], one may infer that the Northeast relied on foreign sources of energy for its emergency electricity production.

Exhibit 1-6. Fuel oil resilience and renewable output, ISO-NE, Dec 22, 2017–Jan 18, 2018



Average of 166,000 barrels per day consumed during cold period, 1.06 trillion Btus per day

In regions with severely constrained capacity, the situation is more than economic. In the Northeast, oil generation just barely met the need during the BC, accounting for over 30 percent of output on some days in New England and New York. In ISO-NE, fuel oil met or exceeded gas generation every day from December 28, 2017, to January 7, 2018, accounting for 26-36 percent of power generation peak output (Exhibit 1-7).

---

[j] It is not immediately apparent from the NYISO website how much of the "dual-fuel" capacity ran on fuel oil during the event. Public unit generation data becomes available beginning in March, based on EPA emissions data, and even that will be an estimate based on reported CO_2 emissions rates (110-141 lbs/MMBtu for natural gas; 150-176 lbs/MMBtu for oil).

[k] Based on Energy Information Administration (EIA) data, approximately 82 percent of crude oil consumed in PADD I is imported and around 60 percent of middle distillates (kerosene, distillate fuel oil, and residual fuel oil) consumed in PADD I were imported or derived from imported crude. Dividing PADD I imports by the sum of PADD I imports, PADD I production, and flows from other PADDs into PADD I yields a proxy for import dependence. [22]

Exhibit 1-7. Contribution of fuel oil generation to daily peak, ISO-NE

Date	Fuel Oil Generation (MW)	Share of Peak (%)
12/27	3,464	27.7
12/28	5,625	30.3
12/29	5,147	30.8
12/30	4,350	26.6
12/31	4,493	27.4
1/1	4,970	27.5
1/2	5,987	31.1
1/3	5,556	29.3
1/4	4,624	26.7
1/5	6,064	32.8
1/6	6,274	35.7
1/7	6,168	34.9

As the BC intensified, ISO-NE maxed out its oil-firing capacity of approximately 6,200 MW. As a result, oil generation averaged approximately 115,000 MWh/day over the period, compared to only 16,200 MWh/day in 2014, a factor of 7 difference (Exhibit 1-6).

Having enough fuel oil was, in part, a testament to ISO-NE's Winter Reliability Program of storing fuel oil at dual-fuel facilities.[l] However, the stores of fuel oil were 51 percent depleted by this event, with some plants nearly or fully exhausting their on-site supplies. Additionally, refueling these depleted fuel supplies is a complex and logistically intense operation; ISO-NE is serviced by a single 50,000 barrel per day oil pipeline to which only two of the region's 83 dual-fuel capable units are connected, which also services home heating oil and other petroleum product demands in the region, necessitating the delivery of fuel oil for power via truck and/or rail, creating supply issues should a similar event last for a longer period.

Gas substitution for this fuel oil would have required 5 Bcf, or a pipeline throughput of 175 MMcf/day. The gas was unavailable due to pipeline constraints, despite available natural gas in nearby Pennsylvania, leading to the extended price spikes. Exacerbating this reliance are the closures of Brayton Point, a 1,530 MW Massachusetts coal plant equipped with modern emissions controls, and Vermont Yankee, a nuclear plant, which together would have generated approximately 700,000 MWh.

[l] The Winter Reliability Program was instituted as a short-term market solution as result of the 2014 Polar Vortex until ISO-NE's Forward Capacity Market 'Pay-for-Performance' incentives (expected to be effective for the 2018/2019 winter season) could take effect. [29]

1.3 PJM AND THE "BOMB CYCLONE"

In PJM, coal and nuclear provided 70 percent of output during the BC, gas 22 percent, and renewables 4 percent. Coal increased an average of 367 GWh/day or approximately 30,000 MW. The surge in coal accounts for 74 percent of incremental energy, with fuel oil 22 percent. Other sources provided little to no surge capacity: natural gas, primarily because of economics; nuclear, because of maxed-out capacity; and wind, due to highly variable output (Exhibit 1-8). On average, wind declined. As detailed above, fuel oil was critical to the northeast, but, in terms of scale, was dwarfed by PJM coal output growth. According to EIA, peak coal generation in PJM of 1,200 GWh on January 5 exceeded the total output of NYISO (500 GWh) and ISO-NE (370 GWh) combined; the aforementioned increase in PJM coal generation was as large as the output of ISO-NE. [8]

Exhibit 1-8. PJM output December 2017-January 2018, average daily GWh[m]

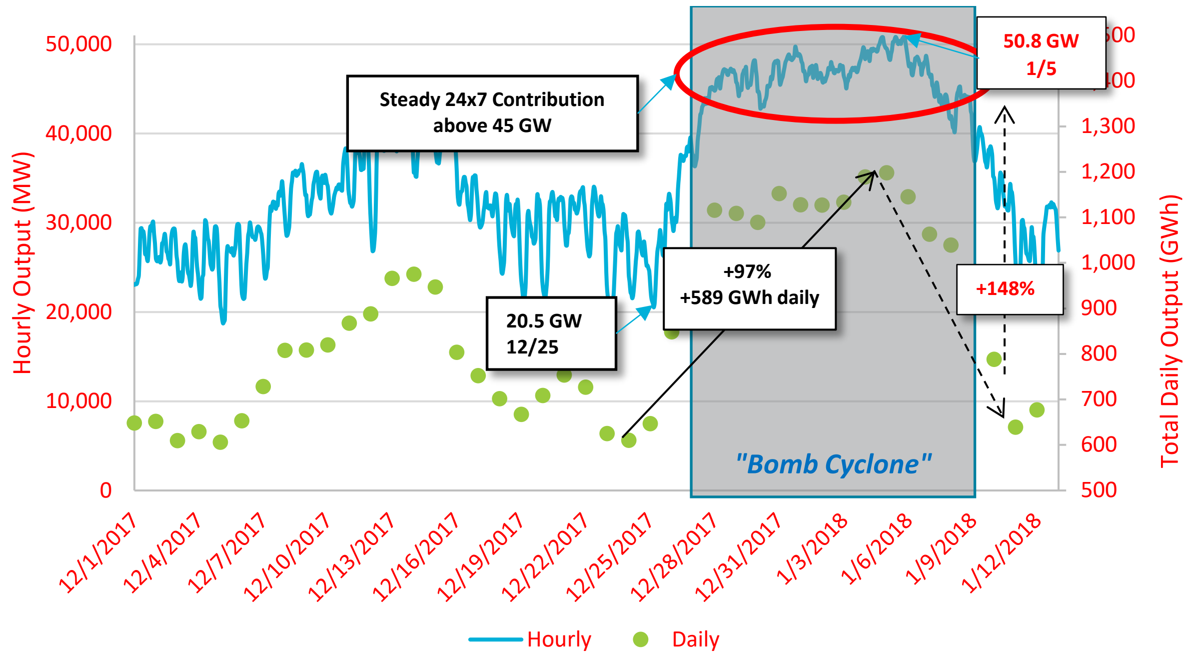
Fuel	12/1-12/26	12/27-1/9	Delta	Percentage Change	Share of Increase
Coal	746	1,113	367	49%	74%
Gas	607	619	12	2%	2%
Renewables	127	123	-4	-4%	-1%
Nuclear	846	851	5	1%	1%
Oil	2	111	109	455%	22%
Total	**2,328**	**2,817**	**496**	**21%**	**100%**

The most prominent example of generation resilience in action, occurred in PJM, the largest of six U.S. RTOs affected by the BC. From the start of the BC, December 27, some coal-fired units were suddenly brought on line and others ramped up to accommodate the rapid increase in PJM electricity demand, providing both absorptive and adaptive capacity. In review and retrospect, coal units in PJM were uniquely positioned to provide the resilience needed at this critical point in time.

As reflected in Exhibit 1-9, during the BC, coal generation in PJM grew from 20 to 51 GW of supplied capacity, utilizing 82 percent of the coal total, to provide 44 percent of total PJM generation on January 4.

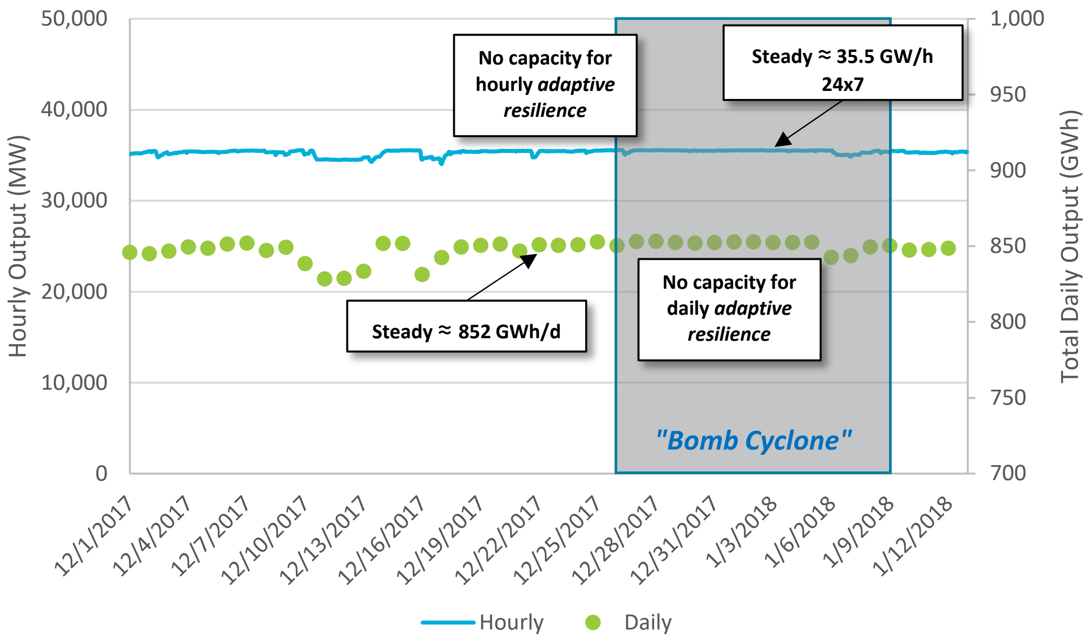
[m] Data from PJM generation fuel data 12/1/17 – 1/25/18 and EIA's "Today in Energy" [7]; Totals do not add up precisely due to rounding.

Exhibit 1-9. PJM coal plant resilience during the Bomb Cyclone



Although nuclear generation represents the quintessentially reliable baseload component of U.S. electricity supply and is critical to meeting base power needs, as shown in Exhibit 1-10, nuclear only provided absorptive resilience capacity because it was already operating at capacity and cannot easily ramp up and down to provide adaptive resilience.

Exhibit 1-10. PJM nuclear plant performance during the Bomb Cyclone

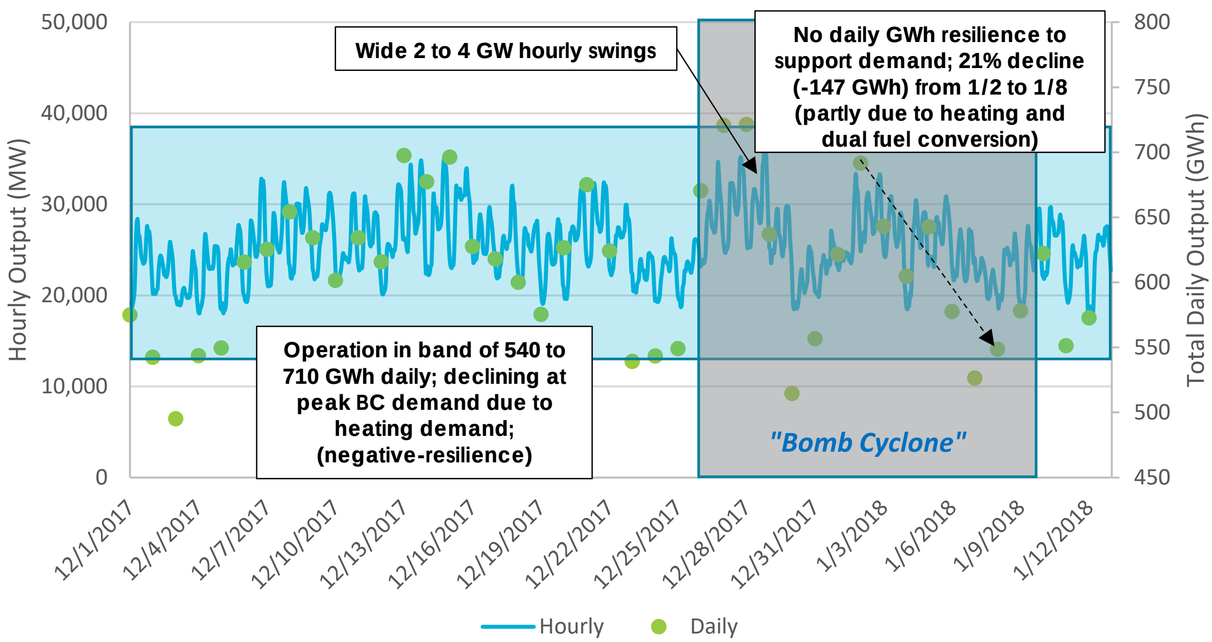


Due to the inherently reliable, but already maxed out operation, of the nuclear portion of the PJM energy mix, as demand increased during the BC, the nuclear share of overall generation dropped from 44 percent before the BC to as low as 26 percent of all generation at peak BC demand on January 5, essentially the converse of coal generation's energy share growth during the BC.

As for natural gas-fired electricity generation, two significant constraints inhibit its fuel resilience contribution during extreme weather events such as the BC. Most importantly, demand from competing sectors, especially from residential and commercial space heating, takes priority over electricity for natural gas use, limiting and even diminishing the capacity potential for natural gas-based electricity. Compounding this constraint is that of pipeline capacity. Even though abundant natural gas may be available, it must flow through the same limited pipeline capacity already delivering to increased heating demand. PJM stands out as a source for low-cost natural gas for electricity, due to rapidly growing Marcellus/Utica regional supply reaching 20 Bcf per day, with constrained pipeline transport, far exceeding its slowly growing 6 Bcf per day regional natural gas demand. When competing space heating demand for natural gas surges during an extreme weather event, natural gas prices rapidly increase, quickly setting the stage for severe spikes in electricity prices as natural gas-fired capacity clears the market. In the case of the BC, natural gas in PJM spiked from a normal level near \$3/MMBtu to \$96/MMBtu at the Texas Eastern M3 interface, in Southeastern PA, at the BC peak on January 5.

Notably, although natural gas fired generation averaged about 25 GW, wide swings in hourly output of up to 4 GW imply that increment was met by cycling natural gas combined cycle units (Exhibit 1-11), and confirmed in PJM's Cold Snap Performance Report of February 26. [9]. Due to these factors natural gas was unable to add significantly to the 22 percent higher daily GWh demand in PJM during the BC. In fact, as total PJM demand increased near the end of the BC event, the natural gas total daily GWh production fell by 21 percent, from January 2-8. As the BC event progressed, natural gas fired generation diminished from a high of 29 percent of PJM hourly electricity on December 26 to a contribution of 16 percent of hourly electricity on January 4. It was coal, and secondarily fuel oil, fired primarily in fuel switching natural gas units, that provided the electricity crucial for keeping natural gas-fired residential furnace fans operating during the extreme cold of the BC.[n]

Exhibit 1-11. PJM natural gas generation performance during the Bomb Cyclone

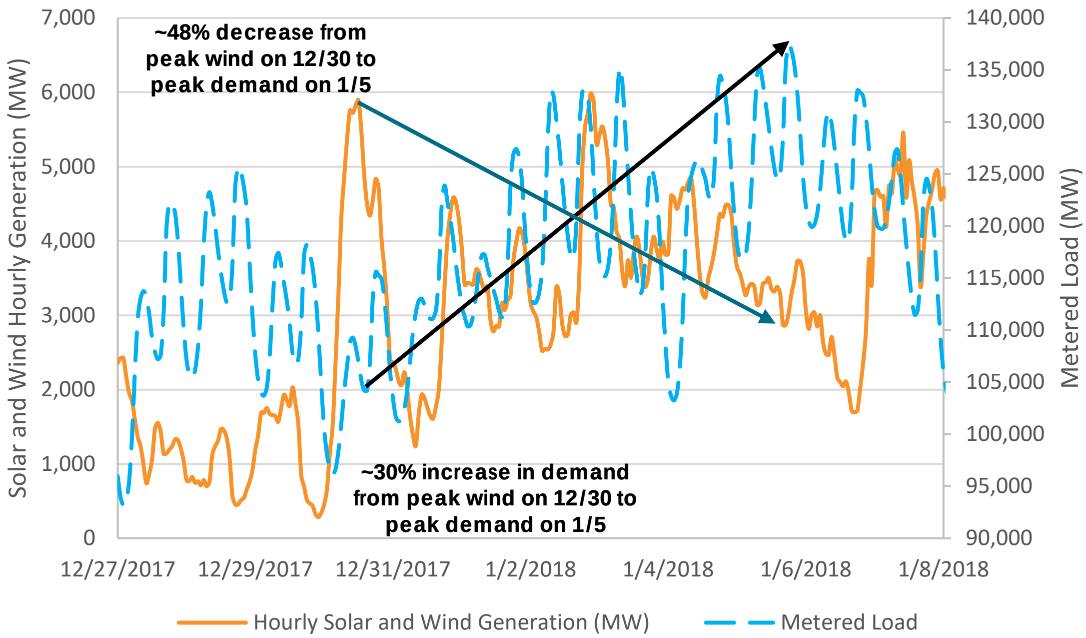


Intermittent generating sources experienced a significant decline nearly inverse to growth in demand. As the storm settled over the Mid-Atlantic region, PJM saw decreased output from solar and wind resources (Exhibit 1-12). This decrease in output essentially imparted a resilience penalty to the system during this event, as it was neither

[n] Dual fuel capability allows for adaptive capacity technology resilience, but does not ensure fuel security and absorptive capacity resilience. In fact, dual fuel switching in some units requires the unit to be completely offline and unavailable while fuel switching occurs, taking 4 to 8 hours on average, essentially creating a window of higher resilience risk. [33]

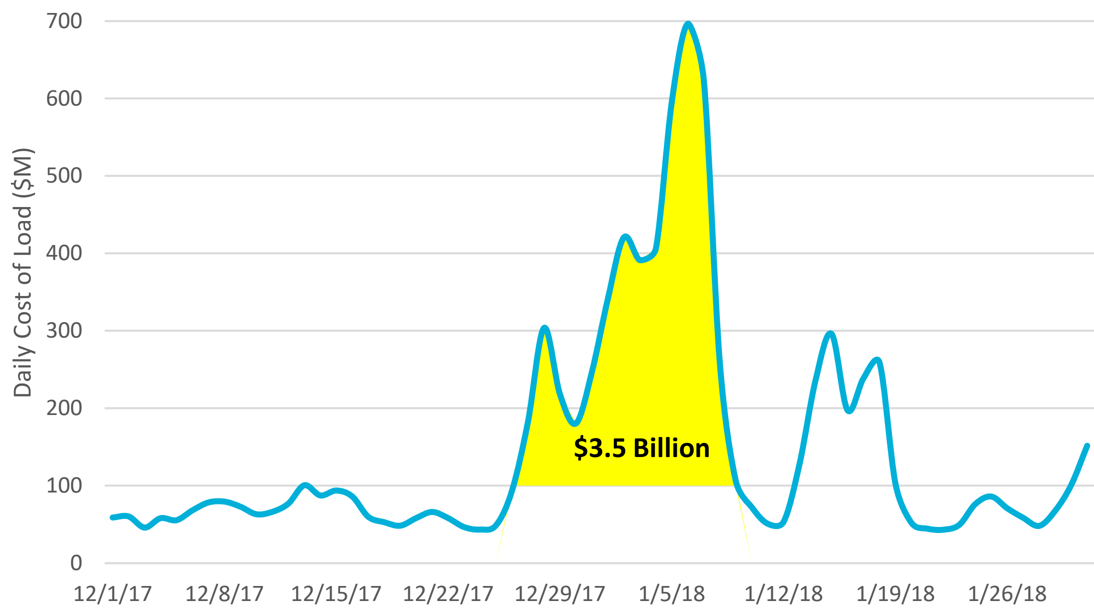
absorptive or adaptive, requiring the remaining available dispatchable resources to provide both forms of resilience to offset the decrease and increasing demand.

Exhibit 1-12. PJM solar and wind generation performance during the Bomb Cyclone



Examining the performance of the major sources of power in PJM leads to the conclusion that it was primarily coal that responded resiliently, with some contribution from oil-firing units. The value of the resilient coal- and oil-fired generation can be quantified by integrating over the term of the BC. The increase in the cost of energy services over the two-week period from December 27 to January 9 was $288M per day, equivalent to $98 per MW, compared with costs from the preceding two-week period, and $225M per day, or $73 per MW, higher than the following two-week period that featured a short return of extreme cold. This, in effect, represents a value of resilience (Exhibit 1-13), which, during the BC, rose to $3.5 billion. Simulating the event for a future state with anticipated coal retirements is expected to produce higher energy costs (including any costs associated with loss of load) and subsequently a higher value of resilience. Further study is needed to quantify this impact.

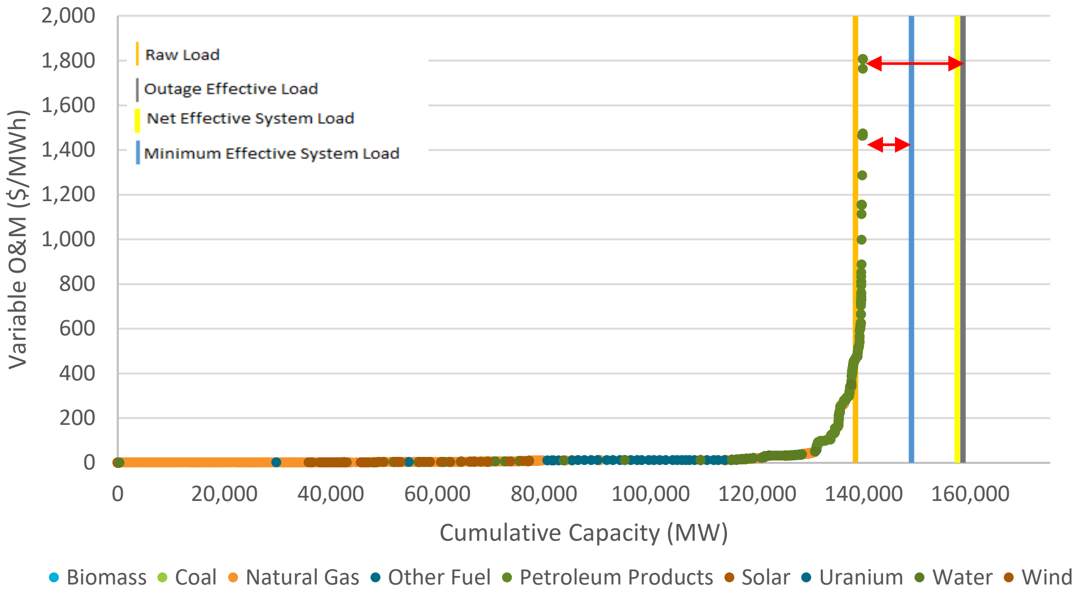
Exhibit 1-13. Notional resilience value[o]



In the case of PJM, it can also be shown that the demand could not have been met without coal. At peak demand, January 5, 2018, natural gas prices exceeded $95/MMBtu in eastern PJM. Had coal been removed, a 9-18 GW capacity shortfall would have developed, depending on assumed imports and generation outages, leading to system collapse (Exhibit 1-14).

[o] Data from PJM. [31]

Exhibit 1-14. Hypothetical PJM Bomb Cyclone peak hour dispatch without coal[p]



*Minimum Effective System Load is hypothetical and does not indicate actual conditions seen by the system, whereas, the Net Effective System Load was seen by the system.

The 30 GW of coal that ramped up to meet the surge in PJM load clearly includes the units most likely to retire due to insufficient market support, given those units were not running at baseload levels before the event. As more of these units retire, the ability of the system to respond to extreme events with reliance, let alone economically, deteriorates. To maintain the resilience seen in this event, any retiring units that were dispatched during the event would have to be replaced with other resilient generation sources and their associated infrastructure (e.g. pipelines, transmission). Due to the timeframe required for permitting, development, and construction, these projects must be well underway prior to potential unit retirements to ensure their availability.

1.4 Six-ISO Summary

Moving to a broader perspective, summing across six ISOs affected by large demand changes (Exhibit 1-15 and Exhibit 1-16) shows that coal is the most resilient form of generation, contributing 63 percent of the 1.2 million GWh net increase in load, with gas following at 20 percent. Fuel oil leapt to 17 percent. Nuclear, being either on or off, contributed 5 percent of the increase. Note however, that across the six ISOs, wind

[p] "Raw Load" is the peak system load reported by PJM during the BC. "Outage Effective Load" is the raw load plus generation outages seen at the peak of the BC. "Net Effective Load" is the outage effective load net of coincident transmission interchange. "Minimum Effective System Load" is outage effective load net of the Capacity Benefit Margin Import Capacity and the Capacity Emergency Import Transfer Limit; this limit is shown to illustrate the best-case scenario for operating the PJM system during the BC without coal-fired assets, and does not indicate actual conditions experienced by the system. Data from NETL analysis utilizing data from S&P Global Market Intelligence and publicly available data from PJM Interconnection.

generation declined over 144,000 GWh. Accounting for the reduction in wind yields nearly 1.4 million GWh of additional generation needed, of which coal provided over 55 percent, fuel oil nearly 22 per cent, natural gas 18%, and nuclear over 4% (Exhibit 1-17).

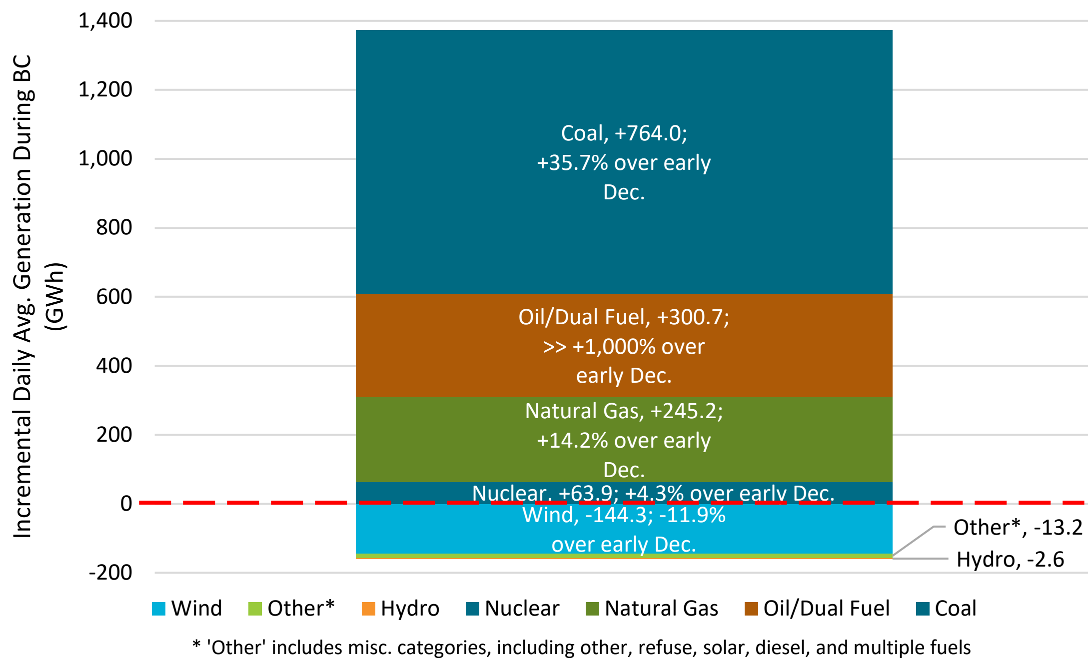
Exhibit 1-15. Six-ISO load change comparison December 1-26, 2017 to Bomb Cyclone (December 27,2017 – January 8, 2018)

RTO/ISO	Total Daily Avg. Load (GWh) 12/1 to 12/26	Total Daily Avg. Bomb Cyclone Load (GWh) 12/27 to 1/8	Delta Daily Avg. Load (GWh)	% Delta Avg. GWh Load
PJM	2,334,041	2,833,454	499,413	21.4%
MISO	1,692,145	2,040,515	348,369	20.6%
ERCOT	949,142	1,038,023	88,882	9.4%
SPP	706,587	819,208	112,622	15.9%
NYISO	353, 199	452,003	98,804	28.0%
ISO-NE	282,556	348,155	65,559	23.2%
Total	**6,317,670**	**7,531,359**	**1,213,690**	**19.2%**

Exhibit 1-16. Fuel-based power generation resilience to load changes from December 1-26, 2017 to Bomb Cyclone (December 27,2017 – January 8, 2018)

Fuel	GWh Delta	% Incremental Share of Net Delta
Coal	763,986	62.9%
Natural Gas	245,227	20.2%
Nuclear	63,915	5.3%
Hydro	(2,591)	-0.2%
Wind	(144,342)	-11.9%
Coal/Oil	20,677	1.7%
Dual Fuel	70,646	5.8%
Residual Oil	209,398	17.3%
Other	(13,226)	-1.1%
Total	**1,213,690**	—

Exhibit 1-17. Fuel based power generation resilience during the Bomb Cyclone, six ISOs



1.4 Comparison to the Polar Vortex

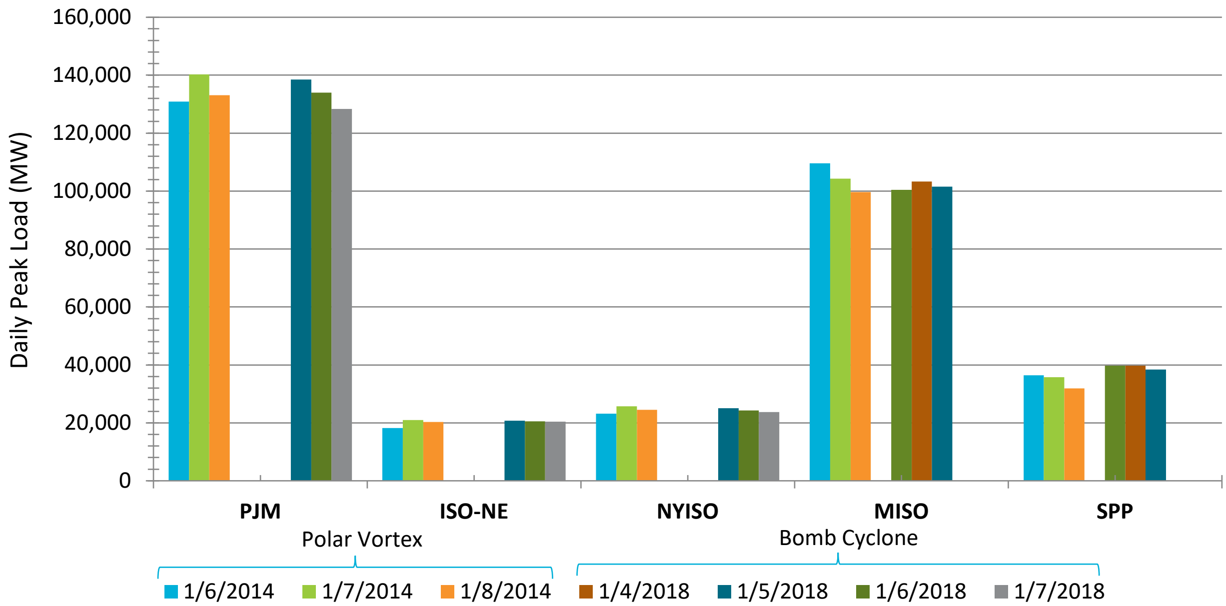
A similar event transpired in January 2014, which saw two distinct weather events, occurring at the beginning and end of the month, the first of which is known as the "Polar Vortex." Natural gas regularly traded above $20/MMBtu in New England, well above the annual average of $5.50/MMBtu, with elevated prices occurring throughout the rest of the nation as well. [10]

In PJM in January 2014, the event was particularly severe due to equipment failures (from the cold temperatures) and unavailability of fuel. Generation forced outages exceeded 10 percent of installed capacity during both 2014 events with a record effective 22 percent forced outage rate (40,200 MW out of 183,000 MW was unavailable) occurring simultaneously with the all-time system winter peak on January 7, well exceeding the 7 percent average winter outage rate normally seen. Natural gas fired generators accounted for 47 percent of the out of service capacity in PJM during this event. [11] In addition to equipment failure, the inability to obtain fuel to start up and/or run the units accounted for 24 percent of the outages. The contemporary PJM report also revealed that over 35 percent of the gas units were unavailable, compared to 18 percent of the coal units. [11]

North American Electric Reliability Corporation (NERC) also analyzed the Polar Vortex. It noted that installed capacity across the Eastern Interconnect and ERCOT was 40 percent natural gas, 31 percent coal, and 19 percent nuclear. With respect to outages, NERC found that while nuclear was mostly unaffected and coal outages were 26 percent of the total, natural gas units composed 55 percent of total outages. This finding led to NERC's conclusion that system planners need to pay particular regard to the performance of natural gas units during extreme weather events. [12]

To bring focus to comparisons of the Polar Vortex with the recent BC, NETL compared similar three-day peak demand periods, January 6-8, 2014, with three consecutive days between January 4-7, 2018 (depending on ISO (Exhibit 1-18)).

Exhibit 1-18. Daily peak load, 2014 v. 2018[q]



Across the five-ISO footprint in 2014, coal generation contributed almost half of total output. Coal and nuclear together provided in excess of 67 percent of generation, gas and oil 33 percent, and renewables less than 0.1 percent, on average (Exhibit 1-19).

[q] Data from ABB Velocity Suite for 2014 Data and ISO Websites for 2018 Data.

Exhibit 1-19. Peak generation mix comparison, 2014 v. 2018, five-ISO footprint[r]

Fuel	Avg. Contribution from 1/6/2014 to 1/8/2014	Avg. Contribution from 12/28/17 to 1/8/18	Net Change
Coal	47.8%	37.8%	-10%
Natural Gas/Oil	33.0%	31.2%	-1.8%
Nuclear	19.1%	20.0%	0.9%
Renewables/Other*	0.1%	11.0%	10.9%
Total	100.0%	100.0%	0.0%

*Renewables/Other includes: Biomass, Wind, Solar, Geothermal, Waste Heat, and other non-traditional generating sources

Due to retirements since 2014, the installed coal and nuclear capacity has fallen, to less than 40 percent in 2018, so that coal and nuclear together compose 57 percent of output in 2018. Remarkably, the share of natural gas did not rise over the four-year interval, despite a 4 percent increase in installed natural gas-fired capacity. Over the five-ISO footprint, the difference was closed with non-intermittent renewables, the vast majority of which are wood-based.[s] Wind and solar capacity increased by 19.6 GW (nameplate); however, only 2.6 GW of that increase is anticipated by the regions at peak in planning studies based on historical peak period performance.[t]

Comparing gas prices for the peak demand day of January 7, 2014, to January 4, 2018, (Exhibit 1-20Exhibit 1-20) reveals peak gas prices two-three times higher in ISO-NE, PJM, and NYISO in 2018 than in 2014. Comparison of electricity prices is more nuanced, as the January 7, 2014, record outage rate (and severe snowstorm, which knocked out transmission) in PJM produced electricity price spikes that had knock-on effects in neighboring NYISO (Exhibit 1-21). Otherwise, electricity price spikes were roughly similar between the period for PJM, ISO-NE, and NYISO. Power prices were lower in MISO and SPP during the 2018 event. An inference to be drawn, then, is that as gas capacity (and therefore gas demand) increases with insufficient deliverability, peak gas prices surge. Very little pipeline capacity has been added in the Northeast (Exhibit 1-22). As a result, flows of natural gas to the Northeast have been static (Exhibit 1-23).[u] In economic terms, the supply of natural gas to the Northeast is essentially fixed by aggregate pipeline throughput.

[r] Data from ABB Velocity Suite for 2014 Data and ISO Websites for 2018 Data. Over both periods, particularly the 2017-2018 period, a preponderance (>75 percent) of generation from sources in this category came from biomass-firing and cogeneration resources.

[s] There is only 89 MW of wood and municipal solid waste facilities planned across the area, with 51 MW of additional capacity planned for ISO-NE.

[t] For a discussion of this, see NETL 2017, *Tracking New Energy Infrastructure*, NETL Pub. 21047, https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=2212.

[u] The EIA has a very broad definition of the Northeast in its state-to-state data, Finer analysis is necessary to determine net flows to New York and New England.

Exhibit 1-20. Regional natural gas spot prices, 2014 vs. 2018

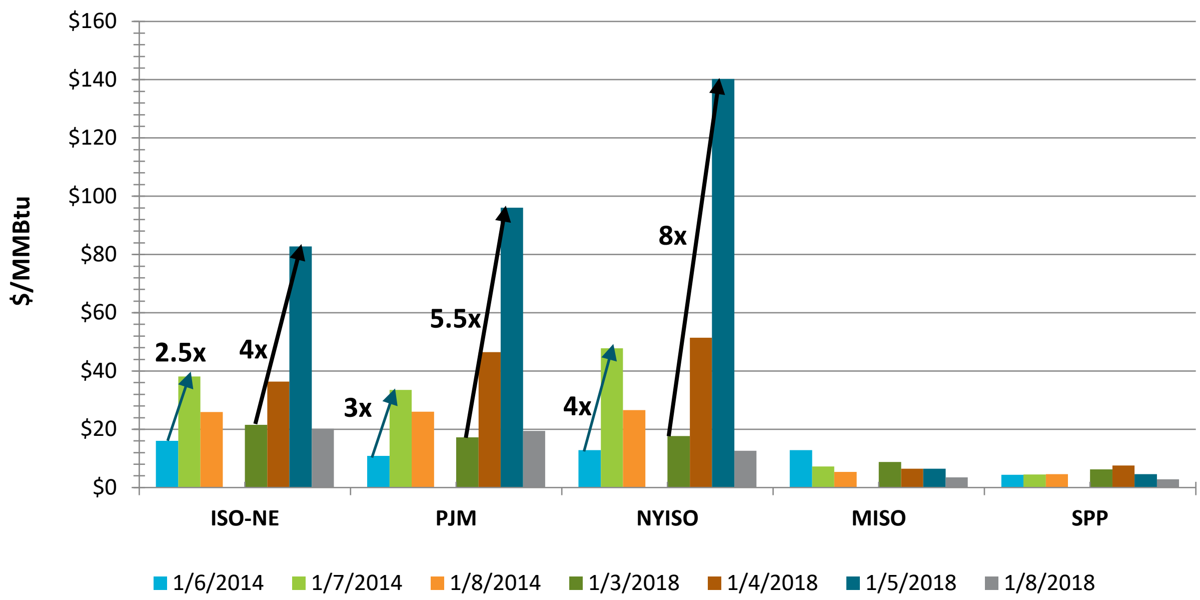


Exhibit 1-21. Daily load weighted average marginal electricity price, 2014 vs. 2018

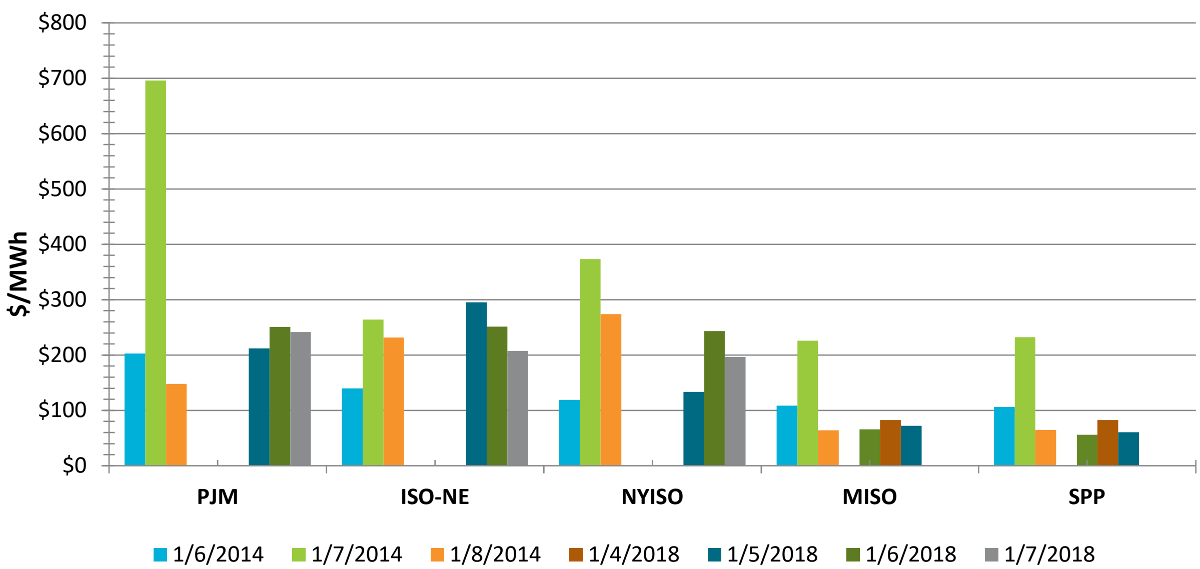


Exhibit 1-22. Natural gas pipeline miles and capacity, 2000-2020[v]

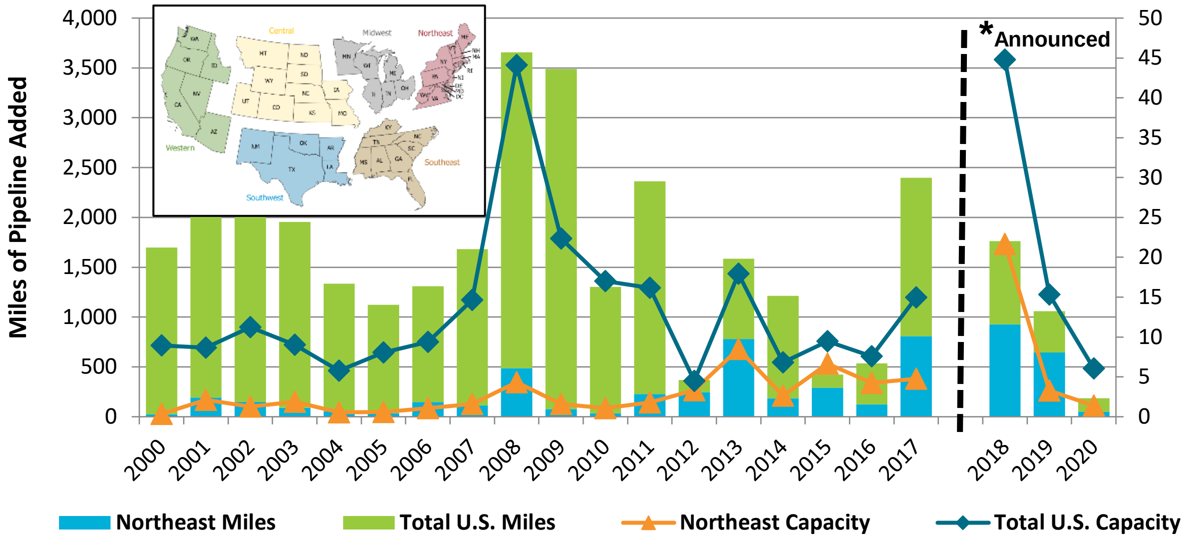
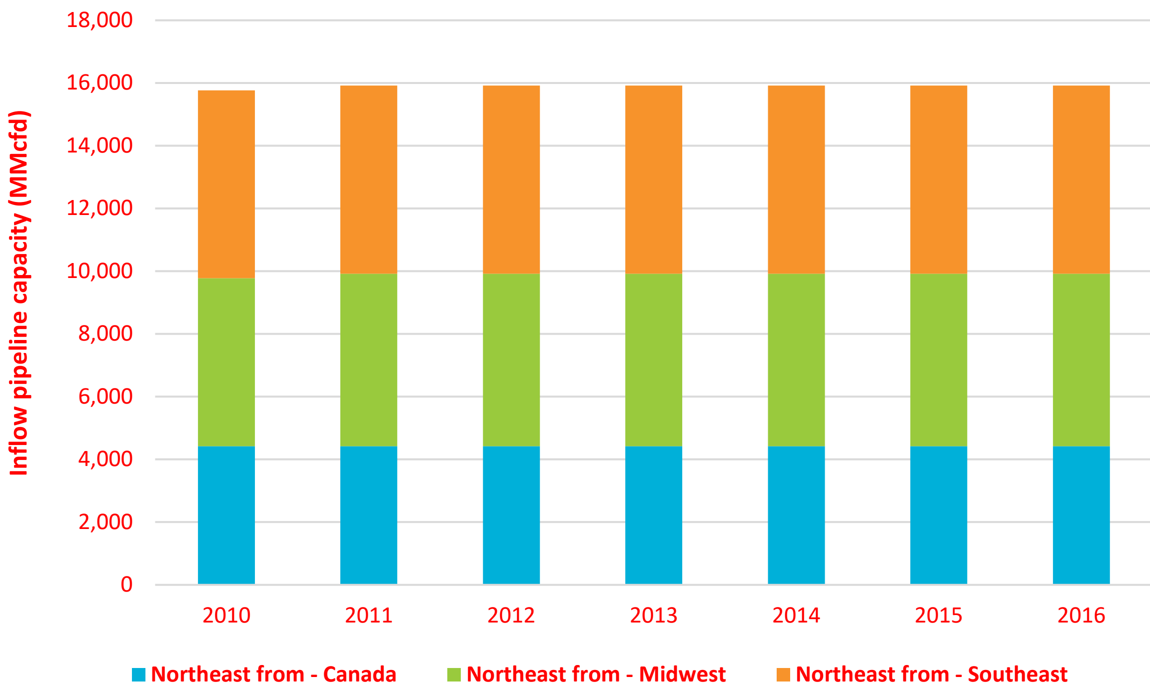


Exhibit 1-23. Natural gas pipeline capacity by year - Inflow to Northeast[w]



Northeast includes VA, WV, MD, DC, DE, PA, NJ, NY, CT, RI, MA, NH, VT, ME

[v] Data from EIA. [24]

[w] Data from EIA State-to-state Pipeline capacity. [24]

2 THE PROSPECT OF FURTHER LARGE-SCALE RETIREMENTS

Generally, the retirement of coal and nuclear generation would reduce reserve margins unless and until sufficient gas-fired power generation capacity is built and adequately served by firm pipeline capacity. However, the tendency to overestimate the ongoing contribution with age of these already mature generating assets is not fully considered in many projections. To the extent that electricity generation projections ignore this factor, the asset replacement scale and lead-time to maintain a diverse electricity fuel mix will be greatly underestimated.

2.1 UNCERTAINTY IN BASELOAD RETIREMENT PROJECTIONS

Based on the analysis presented here, the extent of oncoming coal and nuclear retirements may be underestimated. Through 2025, announced coal retirements total 31 GW across the United States. [13] EIA projects 41 GW of coal and 10 GW of nuclear retirements by 2025.[x] [14] However, neither the currently announced retirements nor the EIA projection adequately captures the risk. The EIA projection includes high capacity factors for remaining coal and nuclear units, even though most units would be over 60 years of age by 2040.

As the age of the coal fleet rises (Exhibit 2-1 and Exhibit 2-2), and the challenges of low gas prices and subsidized, mandated, and/or reduced cost of intermittent renewables continue, the coal units will experience repeated cycling. For instance, the policy-induced 6.6 GW solar growth in California between 2011 and 2017 has led to price collapses during daylight peak as well as induced cycling for California gas units and neighboring Desert Southwest coal units (Exhibit 2-3 and Exhibit 2-4).

[x] No-CPP case.

Exhibit 2-1. Age distribution of baseload units, 2017

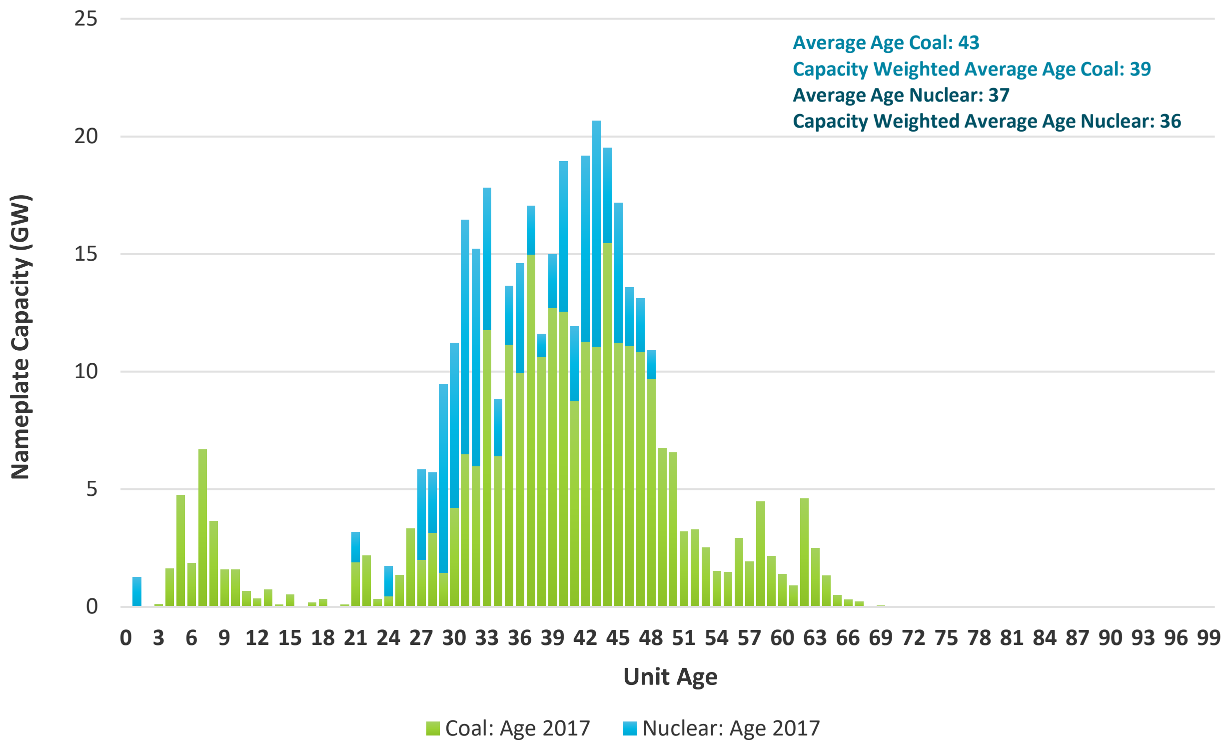


Exhibit 2-2. Unit age in 2040, per AEO 2017

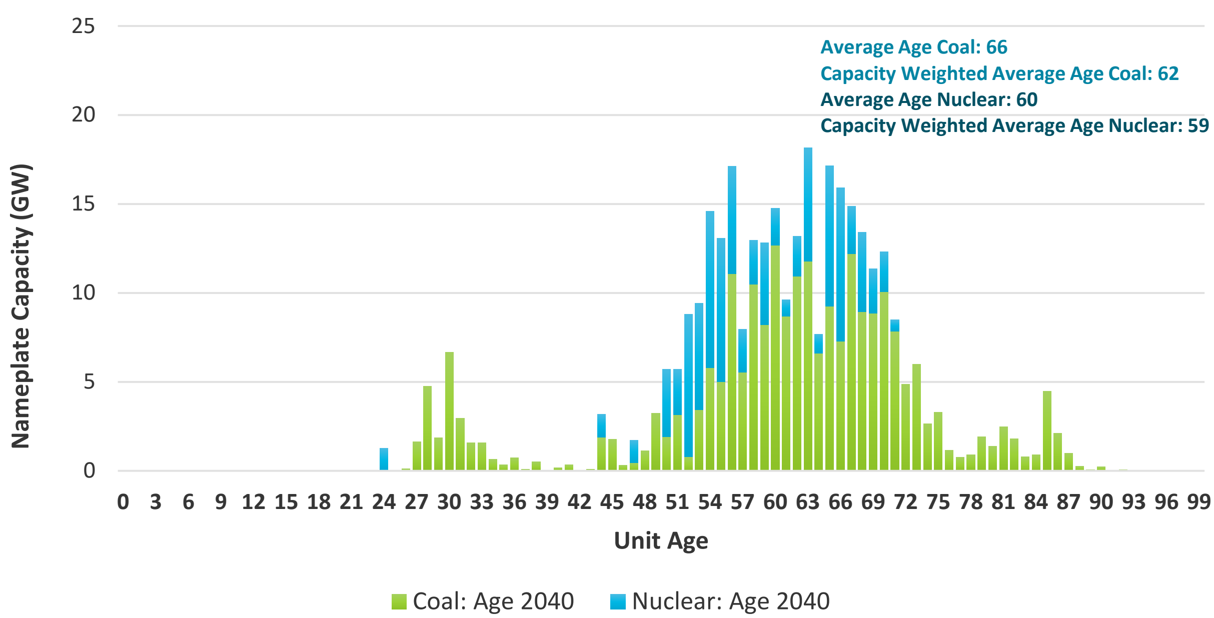
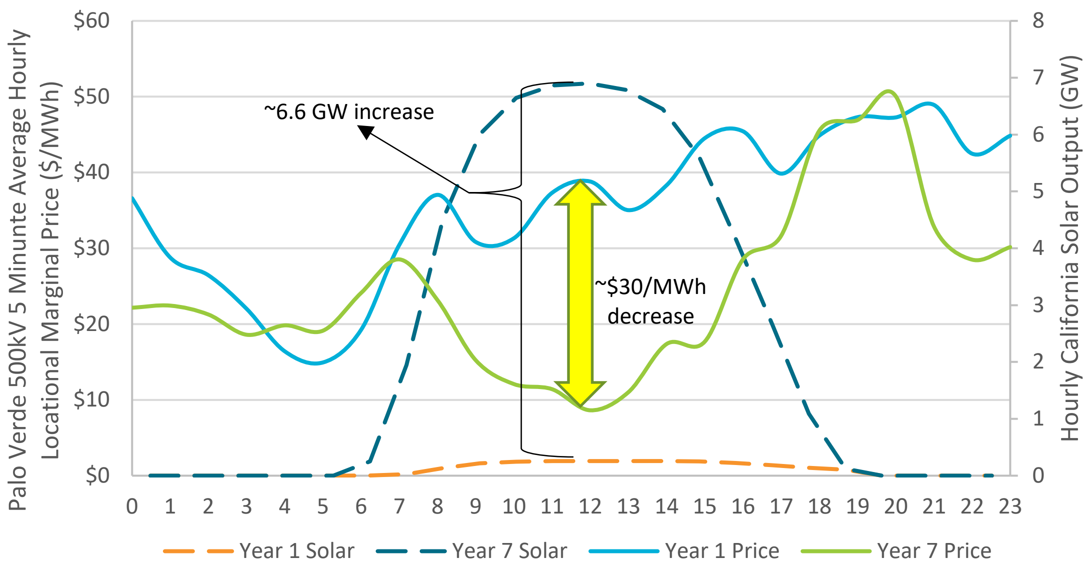
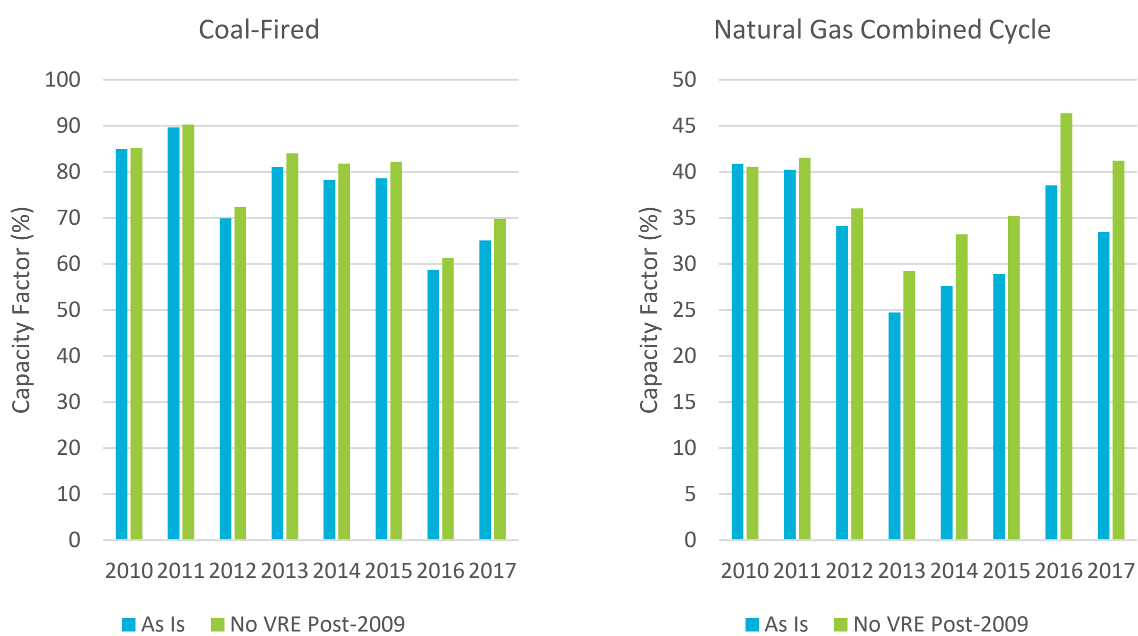


Exhibit 2-3. California solar additions and Palo Verde Prices [y]



Year 1: 4/1/2010 to 3/31/2011
Year 7: 4/1/2016 to 3/31/2017

Exhibit 2-4. Reduced capacity factors in the Western Interconnect [z]



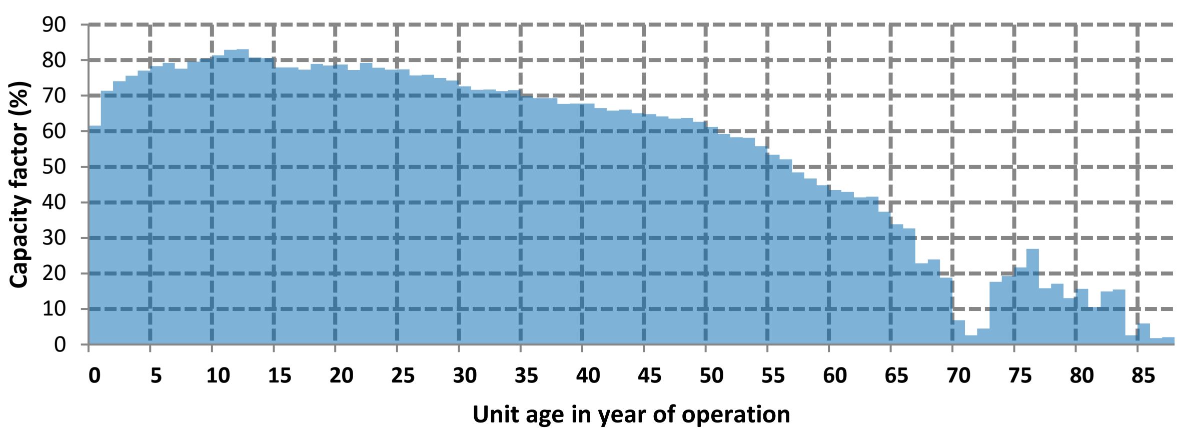
[y] Data from ABB Velocity Suite; Query period 4/1/2010 to 3/31/2017. [14]

[z] Data from NETL simulations using ABB PROMOD IV with and without Variable Renewable Energy (VRE) additions.

Early work on cycling damage minimized the cost, but innovative work by Hanson et al., which internalizes a damage function, shows that as cycling increases, economic damage escalates, leading to premature retirement. [15] This result follows from analyzing the fleet from the perspective of performance versus age. General Electric, ARUP, and others have identified that conventional unit efficiencies decrease by an unrecoverable 0.15-0.55 percent per year, meaning higher operating costs, and reductions in dispatch. [16, 17]

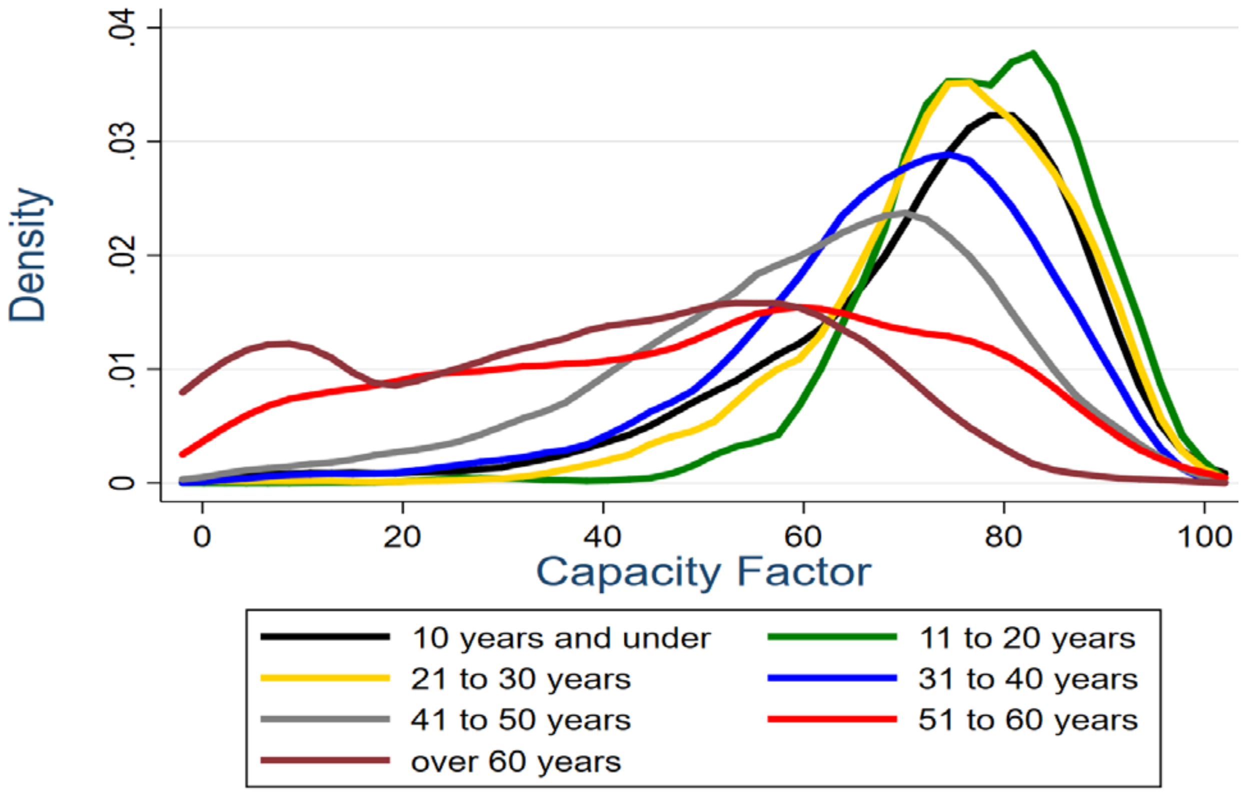
NETL has found declining average capacity factors after units reach thirty years of age, with utilization falling more precipitously after age 50 (Exhibit 2-5). Data show that, at advancing age, capacity factors fall (Exhibit 2-6). EIA held a Coal Fleet Aging Meeting on this topic in June 2016 (an adjunct meeting to its Annual Energy Outlook (AEO) 2017 Coal Working Group).[aa] The combined effects of aging, cycling, and lack of investment is an active area of investigation.

Exhibit 2-5. Average capacity factor for coal units by age of each units in year of operation 1998-2017



[aa] A summary of the meeting can be found here: https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/Final_Coal_Fleet_Aging_Meeting_Notes_081716.pdf

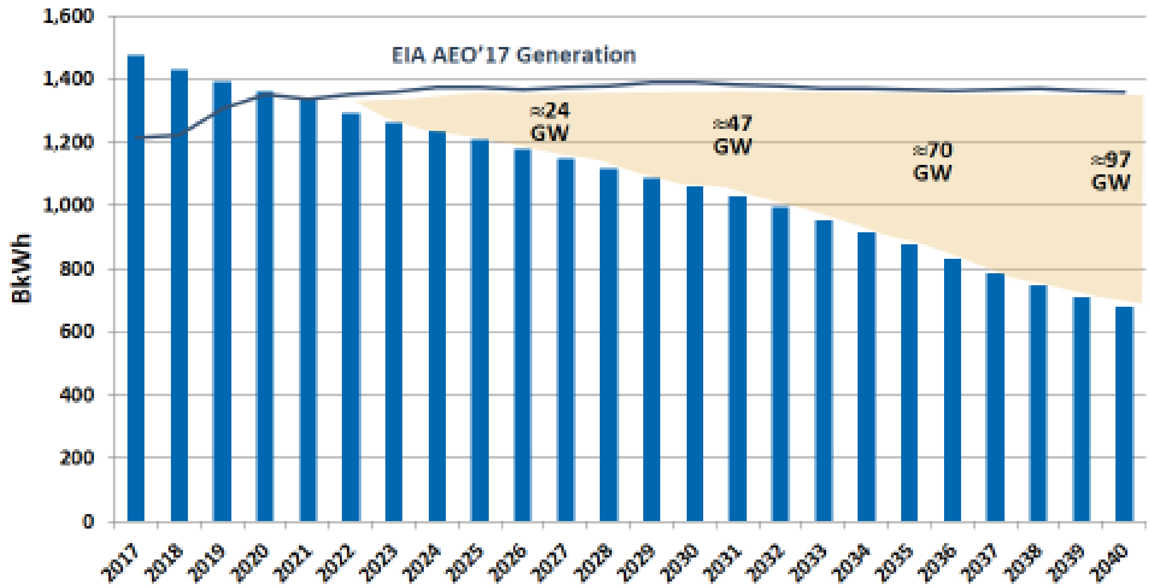
Exhibit 2-6. Kernel density plots of capacity factor by age range (1998 to 2017), weighted by nameplate capacity[bb]



EIA projections result in an average 72 percent average capacity factor for the remaining aging coal fleet. Achieving these baseload-like capacity factors would require substantial capital investment to keep aging units competitive, but since New Source Review significantly limits that investment, the projected capacity factor is not realistic. [18] Moreover, this disconnect gives rise to a hidden generation and capacity gap. The gap advances with the length of the projection period reaching, by 2025, 200 billion kWh compared to the EIA projection (Exhibit 2-7). That would be equivalent to 24 GW of new generation at 80 percent capacity factor and 29 GW at 65 percent capacity factor. More pressingly, it would also equate to 35 GW of retirements of existing units.

[bb] Kernel density estimation uses a non-parametric method to estimate the density function of a variable. One advantage of kernel densities over histograms is multiple distributions can be plotted on top of one another in a density plot; another advantage is density plots tend to result in smoother graphs than histograms. For more information on kernel density estimation, see: https://www.stata.com/manuals13/rkdensity.pdf. Date from ABB Velocity Suite. [14]

Exhibit 2-7. Implicit capacity gap due to aging [cc]



Therefore, by 2025, under these conditions, as much as 75 GW of coal could be retired. In addition, while EIA projects 10 GW of nuclear retirements by 2025, the aging nuclear units also face political and economic challenges. One source estimates from 30-50 GW of nuclear could face retirement. [19] FirstEnergy has announced the likely closures of its Bruce Mansfield coal station in Pennsylvania, as well as the likely premature retirement of its three-plant nuclear fleet in Pennsylvania and Ohio, as it seeks to exit restructured markets (PJM) that in its view do not value reliability nor resilience, and return to wholly regulated status. [20] Reliability in places such as NYISO could also be compromised; the Indian Point nuclear plant is facing retirement as the state proposes an offshore wind farm as direct replacement. As many as 100 GW of baseload retirements may then result in economic distress and give rise to severe reliability, let alone resilience, issues.

In 2015, NETL advised FERC that up to 50 GW of coal could retire within the Eastern Interconnect due to the combined effect of regulation and markets.[dd] [21] That estimate is in line with the calculation above, and resulted from a best estimate equation that considers production cost, emission control cost, and life extension cost.[ee] Eighty-six

[cc] Data from ABB Velocity Suite and AEO 2017 No CCP case generation; [14] [15] missing generation estimate GW @80 percent average C.F. for new units to meet 2040 demand.

[dd] Figures in the referenced presentation were based on *Coal Fleet Transition: Retirement Impacts in the Eastern Interconnection*. [28]

[ee] NETL's "Best Estimate" of coal unit retirements ranked coal units using projected results from the Annual Energy Outlook data broken out by Electricity Market Module (very close to NERC 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 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 coal units in its EMM and the cumulative capacity was summed according to

percent of the units that have retired or have announced retirement since this analysis were identified as High Risk, validating the method.

2.2 Alternatives for Reliability and Resilience with Baseload Retirements

To maintain reliability and resilience, the loss of coal and nuclear generation would have to be replaced with other reliable and resilient generation sources and their associated infrastructure (e.g. pipelines, transmission).

For natural gas to meet this gap, gas-fired generation would have to be built, with equally sufficient pipeline capacity. ISO-NE generators, in particular, have not availed themselves of firm capacity.[ff] [22] ISO-NE recognizes the reliability issue. Recently, it released its *Operational Fuel-Security Analysis*, which across a variety of scenarios sees insufficient reserve capacity, precarious fuel supplies, and the prospect of increasing intermittent renewable additions driving more coal and oil-fired unit retirements, heightening the risk of power outages during the winter. [23] In addition, planned gas capacity is not the same as capacity that will be built. Preliminary NETL analysis indicates that, if all planned gas capacity is built in MISO and PJM, then reserve margins vault to an uneconomic 40 percent level. However, if only those plants presently under construction are built, then, with impending coal and possible nuclear retirements, reserve margins would turn negative. [24] Rationally, a sufficient amount of gas-fired generation needed to maintain adequate reserve margins would have to be built, with equally sufficient firm pipeline capacity, which has traditionally not been subscribed to (contracted for) by power generation. In addition, due to the timeframe required for permitting, development, and construction, these projects must be well underway prior to potential unit retirements to ensure their availability.

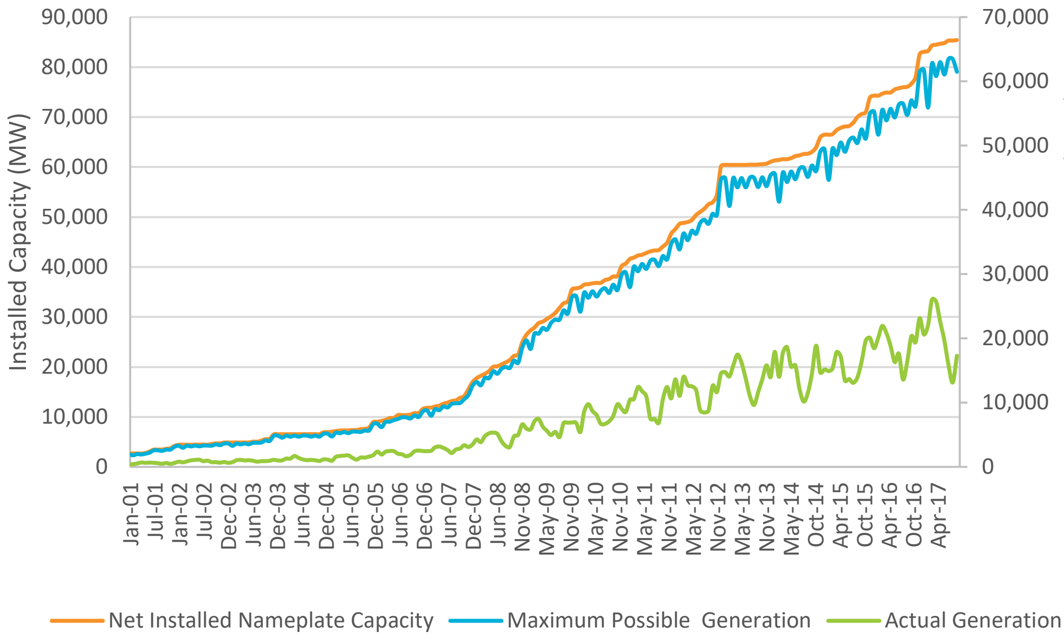
Intermittent renewable capacity additions must be accompanied by energy storage or back-up natural gas (again with firm pipeline capacity) to meet the reliability and resiliency gap that will be left with baseload retirements. As wind capacity and generation grow, even with improvements in capacity factors, the absolute gap between fully loaded theoretical output and actual output widens (Exhibit 2-8). Actual output is also variable on a seasonal basis, most dramatically between spring and summer. The distance, or excess between peak and trough monthly wind output, is itself highly variable, ranging from 33 percent to 98 percent. (Exhibit 2-9). While capacity factors, recently, in winter months are in the low 30s (Exhibit 2-10), the above analysis of the

ranking. Units with announced retirements are moved to the top of the retirement ranking and were categorized as compared to cumulative retirements in each EMM.

[ff] Also see, John Brewer, Paul Myles, Kirk Labarbara, and C. Elise Logan, 2017, *Ensuring Reliable Natural Gas-Fired Power Generation with Fuel Contracts and Storage*, DOE/NETL-2017/1816, www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=2535.

ISOs showed that reliance on wind output would be risky. At least three times as much wind is necessary to replace a coal plant during cold weather months, but wind plants cannot be "ramped up" or dispatched by system operators in response to demand increases.

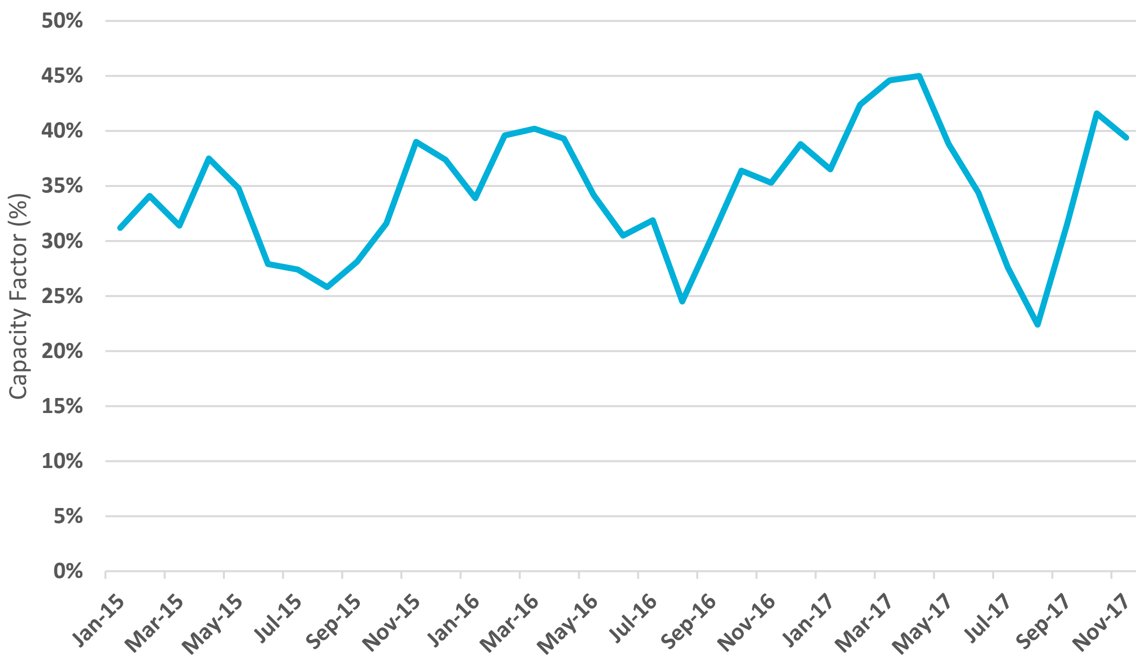
Exhibit 2-8. Monthly U.S. wind output vs. installed capacity[gg]



[gg] Data from EIA, Electric Power Monthly. [29]

Exhibit 2-9. Peak vs. trough wind generation [hh]

Exhibit 2-10. Monthly wind capacity factors, 2015-2017



[hh] Data from EIA, Table 10.2c, NETL calculations. [28]

3 AREAS OF FURTHER STUDY

In subsequent volumes, NETL anticipates performing deeper analysis that includes unit-level data not available for this report. This includes employing the methodology described in Section 2.1 for rigorous identification of at-risk baseload plants and examining the impact and need for advanced technology to meet reliability and resilience in both near and long-term time horizons.

4 REFERENCES

[1] U.S. Department of Energy (DOE), "Fossil Fuels Fight the Freeze," DOE, 2018.

[2] U.S. Census Bureau, "U.S. Census Bureau, 2012-2016 American Community Survey 5-Year Estimates, House Heating Fuel (ID: B25040), 2016 estimate," U.S. Census Bureau, 2016.

[3] U.S. Department of Energy (DOE), "Grid Resiliency Pricing Rule," October 10, 2017, 82 Fed. Reg. 46,940.

[4] Federal Energy Regulatory Commission (FERC), "Docket Nos. RM18-1-000 (Grid Reliability and Resilience Pricing) and AD18-7-000 (Grid Resilience in Regional Transmission Organizations and Independent System Operators), Order Terminating Rulemaking," FERC, January 8, 2018.

[5] ISO New England, "Operational Fuel-Security Analysis," ISO-NE, January 17, 2018.

[6] NGI, "Weekly Gas Price Index," 12 January 2018. [Online]. Available: http://www.naturalgasintel.com/articles/113053-thawing-temps-drop-weekly-natural-gas-spot-prices-as-record-storage-pull-rallies-futures.

[7] National Infrastructure Advisory Council, "Critical Infrastructure Resilience Final Report and Recommendations," 9 September 2009. [Online]. Available: https://www.dhs.gov/publication/niac-critical-infrastructure-resilience-final-report. [Accessed 23 February 2018].

[8] Energy information Administration (EIA), "Today in Energy," EIA, January 23, 2018.

[9] PJM Interconnection, "PJM Cold Snap Performance : Dec. 28, 2017 to Jan. 7, 2018," 26 February 2018. [Online]. Available: http://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx. [Accessed 26 February 2018].

[10] EDF, "Dysfunctional gas market cost New England electric customers $3.6 billion," 2017. [Online]. Available: http://blogs.edf.org/markets/2017/10/11/dysfunctional-gas-market-cost-new-england-electric-customers-3-6-billion/. [Accessed February 2018].

[11] PJM Interconnection, "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events," PJM, https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx, 2014.

[12] North American Electric Reliability Corporation (NERC), "Polar Vortex Review," September 2014.

[13] ABB, "ABB Velocity Suite," ABB, December 2017.

[14] Energy Information Administration (EIA), "Annual Energy Outlook," EIA, 2017.

[15] D. Hanson, D. Schmalzer, C. Nichols and P. Balash, " Donald Hanson, David Schmalzer, Christopher Nichols, and Peter Balash, 2016, “The Impacts of Meeting a Tight CO2 Performance Standard on the Electric Power Sector," *Energy Economics,* vol. 60, pp. 476-485, 2016.

[16] D. R. Dreier, Jr, "Upgradable Opportunities for Steam Turbines, GE Power Generation, GER-3696D," GE Power Generation, 1996.

[17] I. Staffel and R. Green, "How Does Wind Farm Performance Decline with Age?," *Renewable Energy,* vol. 66, pp. 775-786, 2014.

[18] U.S. Department of Energy (DOE), "Staff Report to the Secretary on Electricty Markets and Reliability," 24 August 2017. [Online]. Available: https://www.energy.gov/downloads/download-staff-report-secretary-electricity-markets-and-reliability. [Accessed 20 February 2018].

[19] M. Cooper, "Renaissance in Reverse: Competition Pushes Aging U.S. Nuclear Reactors to the Brink of Economic Abandonment," Vermont Law School, July 2013.

[20] Block News Alliance, "Beaver County plants could be headed for premature closure, as future fades," *Pittsburgh Post-Gazette,* January 25, 2018.

[21] P. Balash, M. Hanley, C. Nichols and T. Tarka, "A Grid in Transition, Near Term Risks and Reliability Concerns," NETL, March 10, 2015.

[22] ABB, "ABB Velocity Suite, Intelligent Query - Natural Gas Pipelines Index of Customers – Contract View," ABB, 2018.

[23] ISO New England, "Operational Fuel-Security Analysis," 17 January 2018. [Online]. Available: http://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf. [Accessed February 2018].

[24] National Energy Technology Laboratory (NETL), "Resilience and Reliability," DOE/NETL, 2018 (forthcoming).

[25] Energy Information Administration (EIA), "Movements by Pipeline, Tanker, Barge and Rail between PAD Districts," 31 January 2018. [Online]. Available: http://www.eia.gov/dnav/pet/pet_move_ptb_a_epc0_tnr_mbbl_m.htm. [Accessed February 2018].

[26] Energy Information Administration (EIA), "Natural Gas Data," EIA, 2018.

[27] Energy Information Administration (EIA), "Annual Energy Review," EIA, 2009.

[28] Energy Information Administration (EIA), "Electric Power Monthly," EIA, January 24, 2018.

[29] Energy Information Administration (EIA), "Monthly Energy Review," EIA.

[30] National Energy Technology Laboratory (NETL), "Coal Fleet Transition: Retirement Impacts in the Eastern Interconnection, DOE/NETL 4001-100814," DOE/NETL, 2015.

[31] ISO New England, "Winter Reliability Solutions for 2015/2016 to 2017/2018 Key Project," 2018. [Online]. Available: https://www.iso-ne.com/committees/key-projects/implemented/winter-reliability-solutions. [Accessed February 2018].

[32] PJM Interconnection, "Data Miner," 2018.

[33] J. Brewer, C. E. Logan, K. Labarbara, R. Wallace, P. Myles, J. Adder and T. Tarka, "ISO New England Dual Fuel Capabilities to Limit Natural Gas and Electric Interdependencies," 22 April 2016. [Online]. Available: https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=2495. [Accessed 20 February 2018].

NETL POC:
Peter C. Balash, Ph.D.
Peter.Balash@netl.doe.gov

www.netl.doe.gov
Albany, OR • Anchorage, AK • Morgantown, WV • Pittsburgh, PA • Sugar Land, TX
(800) 553-7681

NATIONAL ENERGY TECHNOLOGY LABORATORY