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Coal Fleet Transition: Retirement Impacts in the Eastern Interconnection

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Disclaimer

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Acronyms and Abbreviations

ACI	Activated carbon injection
AEO	Annual Energy Outlook
B	Billion
Bcf	Billion cubic feet
BES	Bulk electric system
CO2	Carbon dioxide
CPP	Critical Peak Pricing
CT	Conventional turbine
DCLM	Direct Controlled Load Management
DOE	U.S. Department of Energy
DR	Demand response
DSI	Dry sorbent injection
FGD	Flue gas desulfurization
EE	Energy efficiency
EPA	U.S. Environmental Protection Agency
ESPA	Energy Sector Planning and Analysis
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council, Inc.
GW	Giga-watt
GWh	Giga-watt hour
IC	Internal combustion
IGCC	Integrated gasification combined cycle
ISO	Independent System Operator
ISO-NE	ISO New England
lbs/year	Pounds per year
LMP	Locational marginal price
LTRA	Long Term Reliability Assessment
MATS	Mercury and Air Toxics Standards
MEMP	Market Efficiency Modeling Practices
MISO	Midcontinent Independent System Operator
MRO	Midwest Reliability Organization
MW	Mega-watt
MWh	Mega-watt hour
NEB	Canadian National Energy Board
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NG	Natural gas
NOx	Nitrous oxides
NPCC	Northeast Power Coordinating Council
NYISO	New York ISO
O&M	Operation and maintenance
PJM	PJM Interconnection, L.L.C.
RTO	Regional Transmission Organization
SCED	Security constrained economic dispatch
SCR	Selective catalytic reduction
SERC	SERC Reliability Corporation
SNCR	Selective non-catalytic reduction
SO2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
ST	Steam turbine
TWh	Tera-watt hour
U.S.	United States

Executive Summary

When the United States (U.S.) Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) take effect on April 16, 2015, Eastern Interconnection and other interconnections, as well as their component Independent System Operators (ISO)/Regional Transmission Organizations (RTO), will face many changes in their electric generating fleet compositions. The MATS target air-pollutants such as mercury, arsenic, and metals from power plants, and particularly impact coal- and petroleum-fired electric generating units. (1) When faced with the decision to either install emissions control technologies to achieve MATS compliance or retire plants, the owners of many marginal and aging coal- and petroleum-fired generators have opted to retire the plants rather than expend capital to continue operation.

This report examines the impact of announced retirements on the mix of available generating capacity, prices, resource availability, and air emissions in the Eastern Interconnection. The report uses a security constrained economic dispatch (SCED) model – Ventyx's PROMOD IV 11.1 – of the bulk electric system (BES) to model the interconnection. The first case, "No-Retirements," details the results of BES operation without retirements that have occurred since October 2012 and been announced through April 2014. The second case, "Retirements," shows the results with these retirements included.[1] These retirements netted with Certain Capacity additions would result in a seven percent net reduction of overall generating capacity over the study period.

The analysis found:

- In both cases, **the Eastern Interconnection would experience price increases** and **become increasingly reliant on electricity imports** from other regions during periods of peak demand. These **impacts are exacerbated in the Retirements case**, particularly for prices during periods of peak demand. The report also finds that, **in both cases, as the Eastern Interconnection becomes increasingly reliant on imports from Canada, both Midcontinent Independent System Operator (MISO) and Independent System Operator – New England (ISO-NE) reach their tie line capacity limits for imports**. This could have negative impacts on reliability if parts of the Eastern Interconnection are prevented, by transmission constraints, from importing enough electricity to serve load during periods of peak demand.
- **In the Retirements case, significant capacity additions would be required above those units considered certain in queue**. Incremental additions would be required as early as 2020 to meet peak demand.
- In the No-Retirements case, the Eastern Interconnection is not expected to need any additional capacity.

[1] The Retirements case was developed by aggregating announced retirements from multiple sources (PJM Deactivation List, (19) SNL, (22) Ventyx, (2) and news releases).

The following sections provide a more detailed summary of the modeling results.

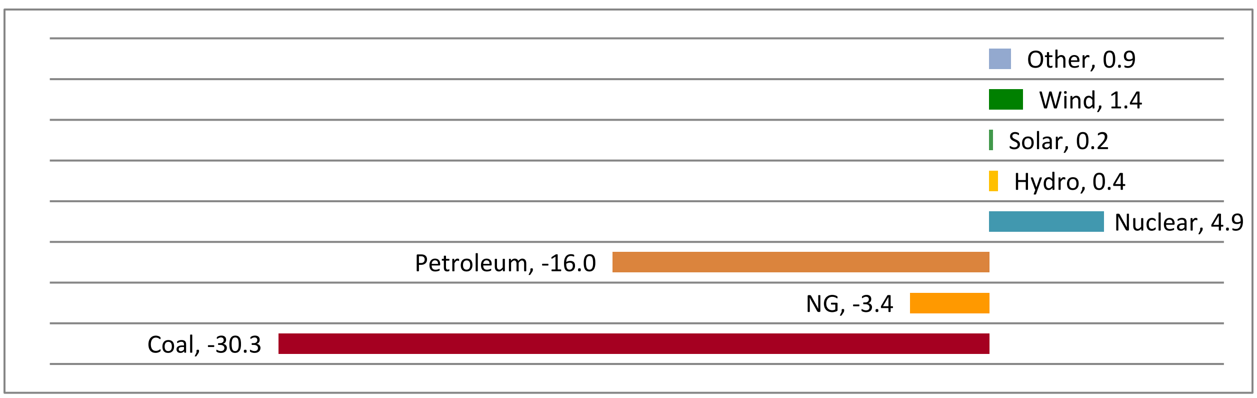
Methodology

The Eastern Interconnection region of the BES is modeled using the SCED model: PROMOD. The model is limited to Certain Capacity additions, which allow for the identification of potential shortfalls within the Eastern Interconnection and provide a basis for calculating the relative cost impact of the Retirements case against a scenario where existing assets do not retire. Certain Capacity includes generating units listed within the Active Generation Queue that are permitted and under construction. Speculative generating units in the Active Generation Queue are omitted due to their uncertain nature. These units include generating units that are proposed, pending approval, or under a feasibility study.

Changes in Generating Capacity Mix

Based on announced unit retirement plans and Certain Capacity additions between 2014 and 2025, the Eastern Interconnection[2] will see a net loss of 41.9 GW of generating capacity, roughly 7 percent of the Eastern Interconnection's total generating capacity in 2014. This constitutes a net loss of 30.3 GW of coal-fired generation, 16 GW of petroleum-fired generation, and 3.4 GW of natural gas-fired generation. The Eastern Interconnection will also see a net gain of 4.9 GW of nuclear capacity and small gains in wind, solar, hydro, and other forms of generation (Exhibit ES-1).

Exhibit ES-1 Cumulative change (GW) of the generation mix for 2014-2025[3]



Source: NETL using Ventyx Velocity Suite Generating Unit Capacity Query (2)

Price Impacts

The anticipated loss of generating capacity combined with a projected one percent compound annual increase in demand in the Eastern Interconnection over the time period analyzed in this report shows that for the Retirements case, the average on-peak locational marginal prices (LMP)[4] are projected to increase by 70 percent to $58/MWh. In the No-Retirements case, the

[2] For the purposes of this report, the term Eastern Interconnection refers only to the U.S. portions of the interconnection.

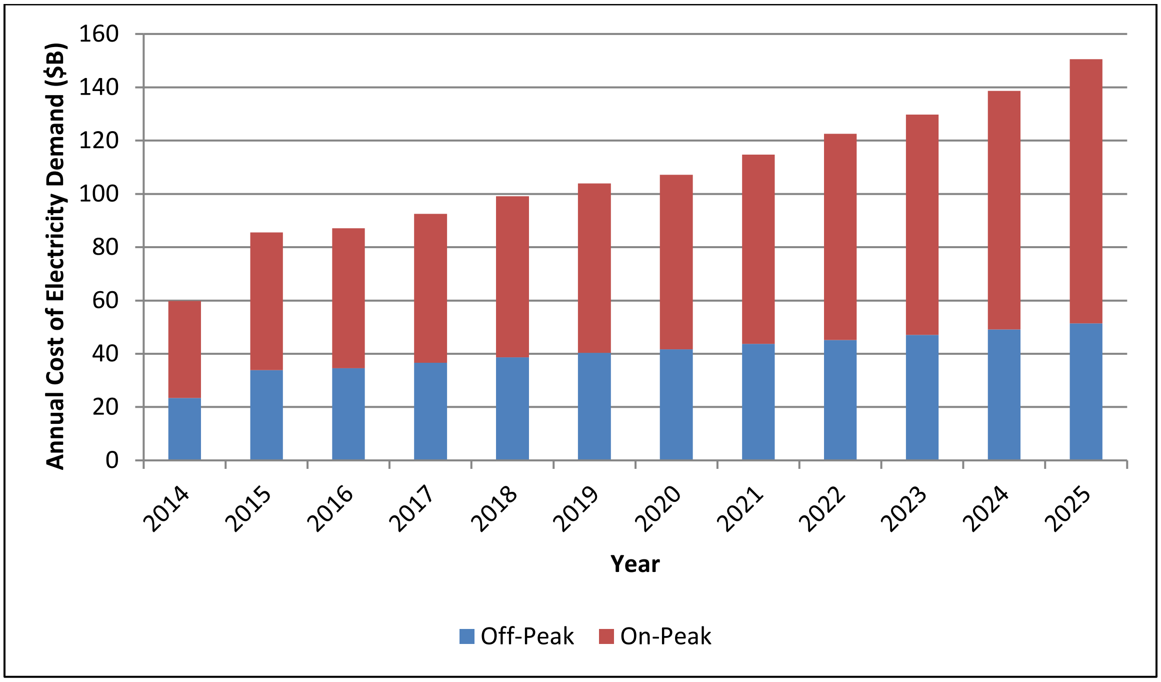
[3] Other generation includes the cumulative change of other (0.12 GW), landfill gas (0.05 GW), renewable (0.01 GW), and biomass (0.73 GW).

[4] For more information on LMP, see the Power Market Primers published by NETL: http://www.netl.doe.gov/research/energy-analysis/publications/details?pub=2bd05cd5-38fd-45ee-81e4-10b33c71018a.

increase is only 40 percent, to $47/MWh. This correlates to a price difference of 19 percent between the two cases in 2025.

The annual cost of electricity to meet total demand for the Eastern Interconnection is higher in the Retirements case than in the No-Retirements case. As shown in Exhibit ES-2, in the Retirements case, the cost increases from $60 billion in 2014 to approximately $150 billion in 2025, compared to approximately $120 billion in 2025 in the No-Retirements case. The difference in the two cases is primarily the result of increased cost to meet on-peak demands in the Retirements case, which increases by nearly $63 billion over the period compared to $13 billion in the No-Retirements case.

Exhibit ES-2 Annual cost of electricity demand in Retirements case (2014-2025)



Reserve Margins and Meeting Peak Demand

The Eastern Interconnection is expected to experience decreasing reserve margins across the period evaluated in this report. In the No-Retirements case, reserves would not fall below the North American Electric Reliability Corporation (NERC) targeted planning reserve level despite decreasing margins, nor would incremental capacity additions be required in order to meet peak demand. In the Retirements case, however, reserves are projected to drop below the NERC targeted planning reserve level during peak hours[5] by the summer of 2021 unless sufficient incremental capacity[6] is added. Exhibit ES-3 below shows that the Eastern Interconnection reserve levels continue to fall, remaining below the planning reserve level during peak demand periods.

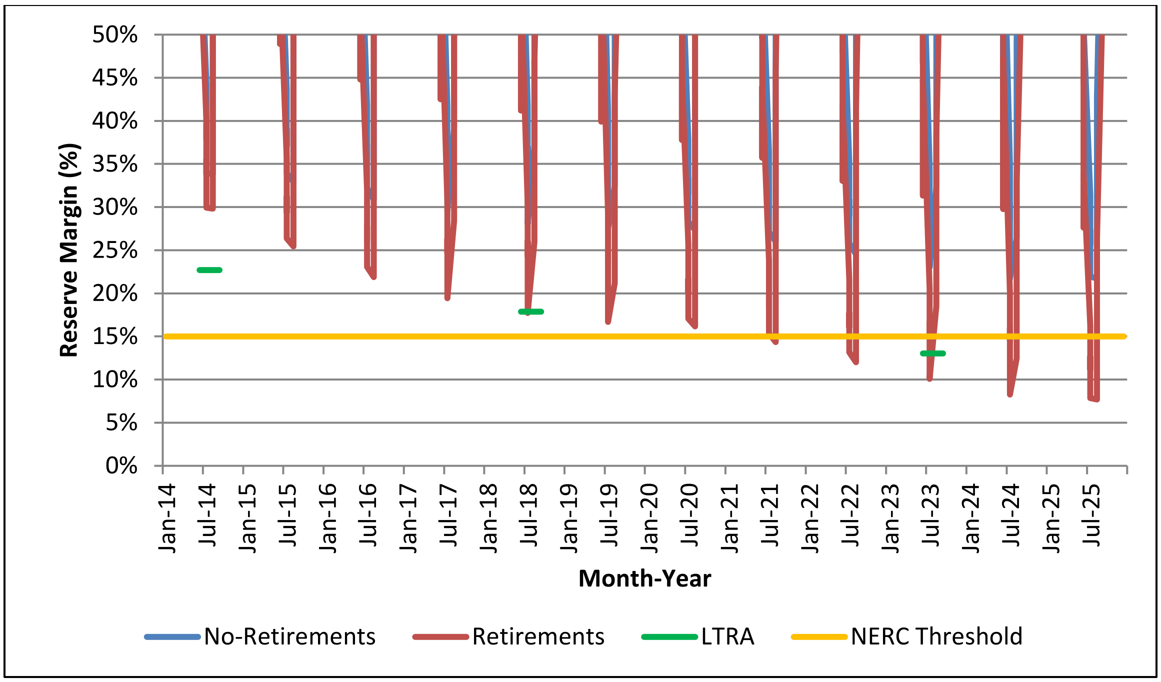
[5] The NERC targeted reserve level for the Eastern Interconnection is 15 percent. (12)

[6] This capacity would be in addition to Certain Capacity units already in the generation queue.

The Eastern Interconnection would require nearly 16 GW of incremental capacity additions by 2025 in order to satisfy peak demand in the Retirements case. Furthermore, over 44 GW of incremental capacity would be required on an annual basis to meet the NERC targeted planning reserve level. These additions, needed to meet peak demand and the NERC targeted planning reserve level, bring the total capacity additions needed to 60 GW.[7]

As noted above, these additions are in excess of Certain Capacity in the queue and exclude any Speculative Capacity. To provide context, the combined generation queues in the Eastern Interconnection currently include 111 GW of Certain[8] and Speculative Capacity with in-service dates between 2014 and 2025. (3) However, according to the Federal Energy Regulatory Commission (FERC) 2011 RTO/ISO Performance Metrics Report, (4) only 12-15 percent of projects within the queue ultimately result in an operating plant, meaning that the likely generation total is between 13 and 17 GW – less than the incremental capacity needed to meet demand.

Exhibit ES-3 Eastern Interconnection minimum monthly reserve margin (2014-2025)



Transmission Imports

The results of the model indicate that the Eastern Interconnection would be increasingly reliant on transmission imports from Canada to meet peak demand. In both cases, imports increase by about 21 percent over the period, with the maximum amount of imports reaching approximately 10 GW. Even though MISO and ISO-NE will receive imports, they will reach their tie line

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[7] Generation required to satisfy the NERC reliability planning requirements was calculated by determining the quantity of generation required to raise the minimum annual reserve margin to planning requirement via backward calculation through the NERC reserve margin calculation, i.e., Generation Required = [(NERC planning requirement – Minimum Annual Reserve Margin)*Net Internal Demand] – Net Internal Demand, where Net Internal Demand = Total Internal Demand – Dispatchable, Controllable Demand Response. (12)

[8] In this instance, certain generation includes both existing-certain and planned-certain generation.

capacity, thus creating a potential for significant reliability issues, particularly for MISO where imports may provide the main method of relieving a 5-7 GW RTO projected capacity shortfall by 2016/2017. (5)

Generation Utilization and Fuel Consumption

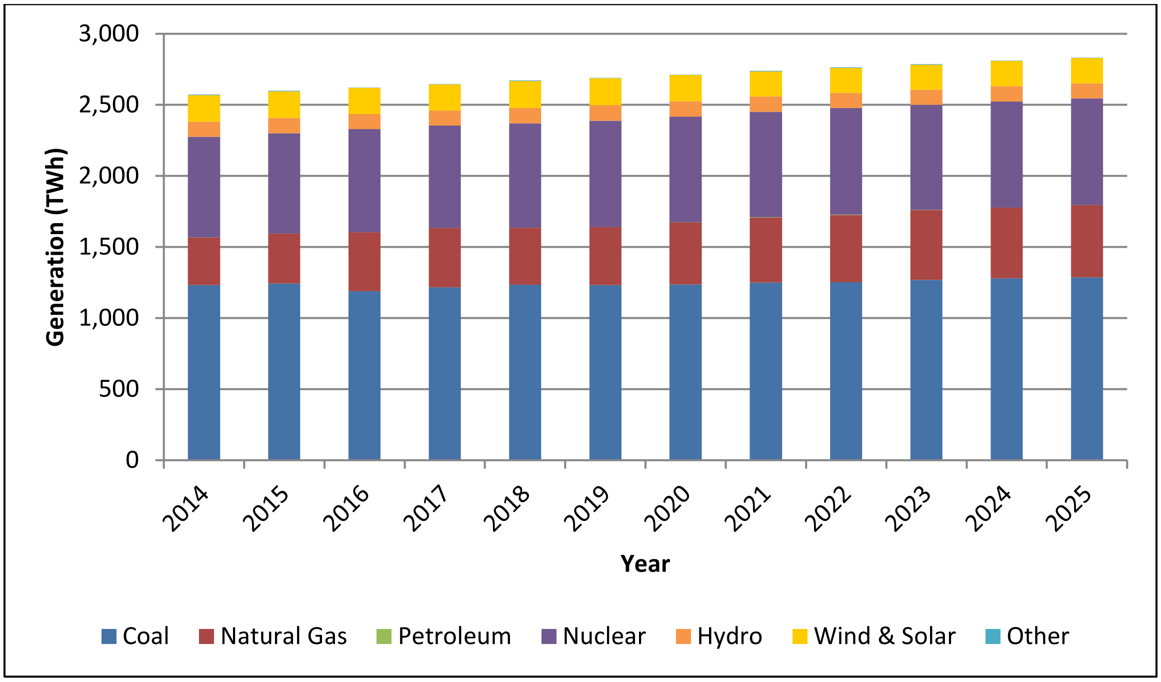
Although available capacity differs under the Retirements and No-Retirements cases, generation dispatch remains fairly consistent. Under both cases, coal-fired and nuclear generation continue to service the majority of load in the Eastern Interconnection. In the Retirements case as seen in Exhibit ES-4, for example, 72 percent of demand within the Eastern Interconnection would still be served by coal-fired and nuclear generation, with natural gas-fired generation providing only a small portion of the overall mix.

In each case, generation from nuclear increases slightly. Generation from coal experiences overall growth under both cases, although that growth is more modest in the Retirements case. Natural gas generation is the reverse – showing greater increases over the period under the Retirements case.

Capacity factors for natural gas-fired generation increase under both cases, although to a greater extent under the Retirements case. For natural gas-fired combined cycle units, annual capacity factors increase from 24 to 29 percent under the No-Retirements case, and from 25 to 35 percent under the Retirements case. Capacity factors for steam coal units also increase more under the Retirements case, from 57 to 67 percent, compared to the No-Retirements case, where it only increases from 54 to 59 percent.

Coal consumption grows slightly under both cases, increasing by 17 percent to reach 767 Mtons of annual consumption under the No-Retirements case, and increasing by 7 percent over the period to reach 739 Mtons for the Retirements case. Natural gas consumption shows a greater increase in both cases: rising by 32 percent under the No-Retirements case and 56 percent under the Retirements case.

Exhibit ES-4 Eastern Interconnection generation by fuel type in Retirements case (2014-2025)



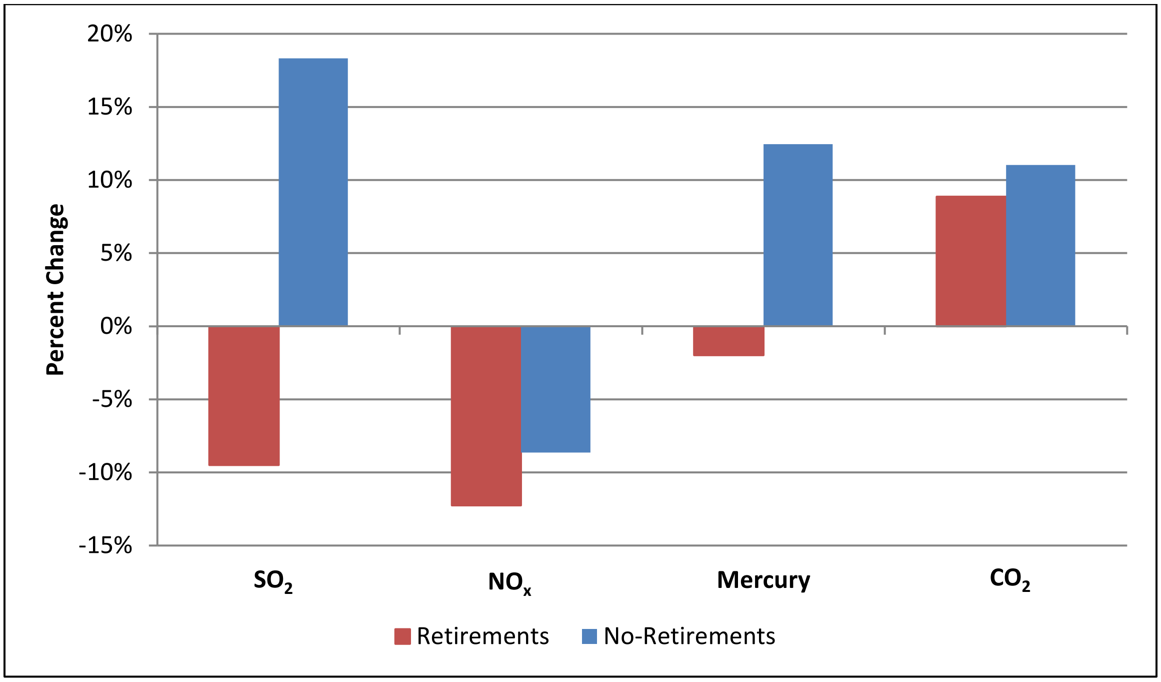
Emissions Profile

The MATS rule targets criteria air-emissions from power plants. It was found that in the Retirements case, where any non-MATS compliant power plants would be retired, criteria air emissions experience a net decrease of between 2 percent (Mercury) and 12 percent (NO_x) over the period, as seen in Exhibit ES-5. The bulk of this decrease occurs in the short-term following retirements, after which emissions remain steady or grow slightly over the remainder of the period.

NO_x emissions also decline under the No-Retirements case, by nearly 9 percent over the period. For SO_2 and Mercury under the No-Retirements case, emissions increase by 18 and 12 percent, respectively.

CO_2 emissions, which are not covered under MATS, increase steadily for both cases over the period, with the emissions in the No-Retirements case increasing slightly more: 11 percent versus 9 percent for the Retirements case.

Exhibit ES-5 Change in emissions from 2014-2025



1 Overview and Methodology

1.1 Overview

The bulk power system is in a state of transition. Factors such as cheap and abundant shale gas, renewable portfolio standards, regulatory and policy changes, and anemic demand due to the recent "Great Recession" – to name only a few – have changed the dispatch order, impacted capacity markets, and generally injected uncertainty into what the market will value in the near future. (6) (7)

One of the many changes impacting not only the Eastern Interconnection, but other interconnections, as well as individual Independent System Operators (ISO)/Regional Transmission Organizations (RTO), is the United States (U.S.) Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), which targets reduced emissions from coal- and petroleum-fired electric generating units. (8) The stringent reduction levels and short compliance time set forth in MATS (units must be compliant by April 16, 2015, or obtain a one-year extension), combined with the aforementioned market and policy uncertainty, have led to a decision by operators to retire many marginal and aging coal- and petroleum-fired generators rather than incur costs to install emissions control technologies required for MATS compliance.

This report evaluates the potential impacts of widespread coal-fired capacity retirements on the bulk power system in the Eastern Interconnection by examining two potential cases. The first case, "No-Retirements," details results of power system operations considering units that have retired since October 2012 and those that have announced retirement plans through April 2014 as continuing in operation. The second case, "Retirements," shows the results with these retirements occurring, as expected.[9] This report highlights the comparison of these two cases, and their impacts on the Eastern Interconnection's ability to meet demand and the associated costs in each case. This is done using a bottoms-up simulation of the entire Eastern Interconnection, as modeled in Ventyx's PROMOD IV 11.1: an electric market simulation tool. (9)

1.2 Methodology

Since the ultimate goal of this report is to provide a bottoms-up analysis of the generation shortfalls and power system impacts of retirements beginning at the ISO/RTO level and ending at the national level, it was decided to model the entire Eastern Interconnection as the simulation area. Each of the component regions was modeled using the same methodology and summarized in its own report.

Both cases were simulated using PROMOD IV 11.1 (9) and were constructed in close accordance with the PJM Market Efficiency Modeling Practices (MEMP). (10) PROMOD 11.1 is a security-constrained economic dispatch modeling program that utilizes known power system information to identify the most economic utilization of the power system. PROMOD inputs include power plant characteristics for each grid-connected unit, such as heat rates, operation and maintenance (O&M) and fuel costs, interconnection location, and load profiles for each power

[9] The Retirements case was developed by aggregating announced retirements from multiple sources (PJM Deactivation List, (26) SNL, (22) Ventyx, (2) and news releases).

system balancing area. With respect to the simulation area, the PJM Interconnection, L.L.C. (PJM) MEMP recommends modeling only a target ISO/RTO and its immediate neighbors. However, since the target area of this simulation was the U.S. portion of the Eastern Interconnection, the entire interconnection was simulated, inclusive of Canadian system areas.

Power demand and interruptible generation values for the models were drawn from the load forecasting reports generated by each ISO/RTO or from FERC Form 714 reports in the absence of an ISO/RTO report. (11)[10] Load forecasts for the Canadian system areas were similarly drawn from Canadian utility load forecasting reports or from a combination of the NERC Long Term Reliability Assessment (LTRA) and the Canadian National Energy Board's (NEB) Canada's Energy Future 2013 Report, in the absence of a utility forecast. (12) (13)[11] Load forecasts for both U.S. and Canadian areas include embedded assumptions for implemented energy efficiency programs. This report makes no assumptions about additional energy efficiency penetration beyond the levels included in these forecasts.

Fuel price projections were taken from the Energy Information Administration's Short Term Energy Outlook (for near-term prices through December 2015) (14) and 2014 Annual Energy Outlook (for long-term prices beyond December 2015). (15)

The simulations also include announced generator emissions control projects with respect to those adjusted emissions rates that were effective on the anticipated project in-service date.[12]

A key difference in the methodology used for these cases and the MEMP was the inclusion of Speculative Capacity[13], as opposed to just Certain Capacity, to maintain reserve margins and the aforementioned simulation area. Both Certain Capacity and Speculative Capacity are defined in Exhibit 1-1. Whereas the MEMP recommends including Speculative Capacity from interconnection queues on a fuel type and zonal percentage basis to maintain reserve margins, these simulations did not include Speculative Capacity so that the quantity of additional capacity required could be identified.[14] This allows for the identification of potential shortfalls within the Eastern Interconnection and provides a basis for calculating the relative impact of the Retirements case against a scenario where existing assets do not retire.

[10] Load forecast reports from PJM, NYISO, and ISO-NE. FERC Form 714 reports were used for SPP, SERC, and MISO. (11)

[11] Load forecast reports from Independent System Operator Ontario, Manitoba Hydro, Hydro-Québec, and Nova Scotia Power were used. The LTRA and NEB reports were used to bridge gap years between the utility forecasted years and the end of the modeled time period.

[12] Announced emissions control projects and their status are tracked on a bi-monthly basis for NETL. This tracking product was used as the basis for the 41 emission control projects within the Eastern Interconnection that were included in these cases A list of these projects can be found in Appendix C.

[13] Speculative Capacity takes into consideration the time it takes for a power plant to go through the proposal, feasibility and permitting stages. According to Alstom, new power plant construction can range from 2 years for a combined cycle plant, 3-4 for a coal plant, and 10 years for a new nuclear plant once construction begins. (25) Prior to the start of construction, plants must also progress through the regulatory permitting process and the PJM Generation Interconnection Process, normally concurrent processes which can take 18 months or longer. (24) When combined, this corresponds to an effective earliest in-service date of 2017 for a combined cycle plant announced in 2014.

[14] MEMP recommends including aggregated speculative active queue capacity for each component transmission zone of PJM based on the composition of the active queue capacity by fuel type in that zone to maintain reserve margins. For example, if the Duke Energy Ohio/Kentucky zone requires an additional 1,500 MW to maintain reserve margins and 25 percent of the speculative queue for the zone is gas-fired, then 375 MW (1,500 * 0.25) of gas-fired capacity would be added by the MEMP. (10)

Exhibit 1-1 Types of capacity

Future Capacity Classification	Definition
Certain Capacity	"Certain" capacity includes generating units listed within the Active Generation Queue that are permitted and under construction. Certain capacity includes two types of capacity, existing and planned. Existing-certain capacity is that which has completed construction, but is not yet delivering power to the electric grid. Planned-certain capacity is that which is currently under construction. Throughout this report, unless otherwise noted, certain capacity is considered to be the aggregate of existing and planned certain capacity.
Speculative Capacity	New speculative units include generating units that are proposed, pending approval or under a feasibility study.

2 Eastern Interconnection Overview

The Eastern Interconnection will see the largest magnitude of impacts from MATS in terms of retiring capacity and new additions of the four North American electric system interconnections, shown in Exhibit 2-1. The Eastern Interconnection consists of the following ISOs/RTOs which span portions of both the U.S. and Canada:

- In the U.S.:
  - Florida Reliability Coordinating Council, Inc. (FRCC)
  - Independent System Operator-New England (ISO-NE)
  - New York ISO (NYISO)
  - PJM Interconnection, L.L.C. (PJM)
  - SERC Reliability Corporation (SERC)
  - Southwest Power Pool, Inc. (SPP)
- In the U.S. and Canada:
  - Midcontinent Independent System Operator (MISO)
  - Midwest Reliability Organization (MRO)
- In Canada:
  - Hydro-Quebec
  - Independent Electricity System Operator (Ontario)
  - Maritimes

Exhibit 2-1 NERC interconnections

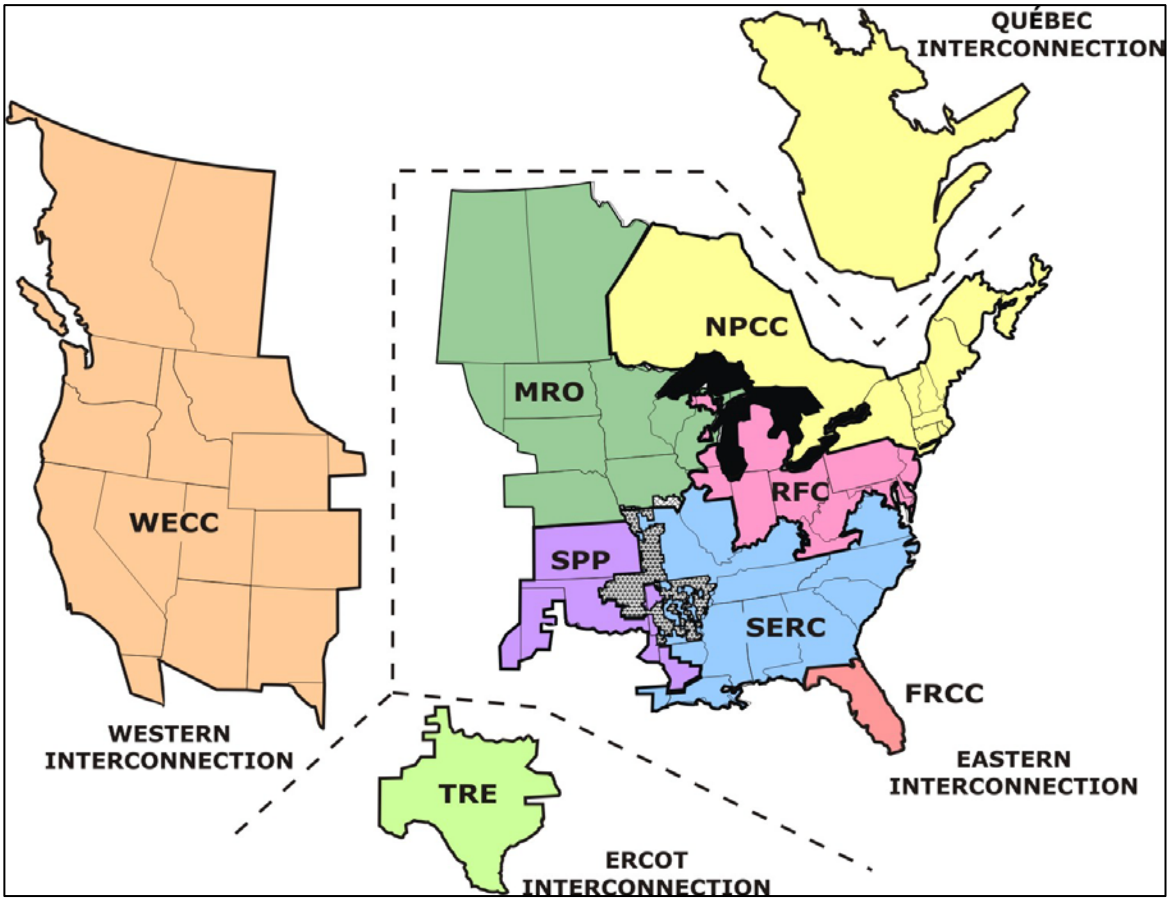


Image used with permission from NERC

For the purposes of this report, the Quebec Interconnection in Canada was also considered part of the Eastern Interconnection. While the simulations forming the basis of this report were executed for the entirety of the Eastern Interconnection, spanning both the U.S. and Canada, the results presented are singularly for the U.S. portions of the interconnection.

From 2014 to 2025, the Eastern Interconnection will witness a net loss of generating capacity equivalent to 12 percent of its total 2014 generating capacity. This loss comes from the retirement of fossil fuel-fired generation, as seen in Exhibit 2-2. Over the studied period, natural gas-fired generation additions in the Eastern Interconnection will be less than the amount of retiring natural gas-fired generation. By 2025, the Eastern Interconnection is expected to experience a net loss of over 30 GW of coal-fired generation as a result of regulatory and market pressures, which will need to be replaced by other generation sources since the amount of new natural gas-fired generation coming online will not be sufficient to replace both coal- and natural gas-fired retirements.

During this same period, peak summer load in the Eastern Interconnection is projected to increase by 10 percent. While callable demand response (DR) resources may be available to offset a portion of these peak summer loads, the combination of expected load increases and net capacity losses places the Eastern Interconnection in a potentially precarious situation.

Exhibit 2-2 Eastern Interconnection capacity changes (2014-2025)[15]

	New (GW)	Retired (GW)	Net Change (GW)
Natural Gas-Fired Generation	19.96	23.33	-3.37
Coal-Fired Generation	1.96	32.24	-30.28
Petroleum-Fired Generation	0.001	16.04	16.04

Source: NETL using Ventyx Velocity Suite Generating Unit Capacity Query (2)

2.1 Capacity Changes

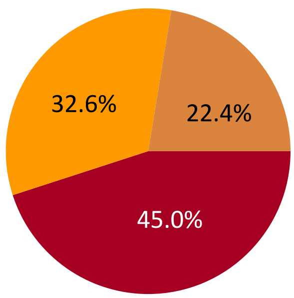
Nearly 72 GW, or 12 percent, of the Eastern Interconnection's 2014 generating capacity will retire in the 2014-2015 period. Coal makes up 45 percent of the generation in the Eastern Interconnection that will be retired, and petroleum makes up another 22.4 percent, which combines for 67.4 percent of the retirements (Exhibit 2-3). When natural gas retirements, 32.6 percent of the retiring generation, are included, all of the retirements will come from fossil sources: natural gas, coal, and petroleum. A majority of these retirements are occurring due to regulatory and economic pressures, particularly from MATS and low natural gas prices.

Of the 31.1 GW of capacity that is planned to be added in the Eastern Interconnection between 2014 and 2025, 64.2 percent will be natural gas-fired, while another 6.4 percent will be coal-fired (Exhibit 2-4). Wind, hydroelectric, nuclear, and other sources make up the bulk of the remaining capacity additions.

The cumulative change in net generation displayed in Exhibit 2-5 shows that there is a net loss of nearly 50 GW of coal, natural gas, and petroleum-fired generation, and only a net increase in capacity of 7.8 GW from other sources coming online through 2025.

[15] Capacity is counted on a January 1, 2014, through December 31, 2025, basis.

Exhibit 2-3 Retiring Eastern Interconnection generation (2014-2025) [71.6 GW]



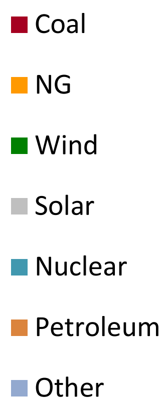


Exhibit 2-4 New Eastern Interconnection generation (2014-2025) [31.1 GW][16]

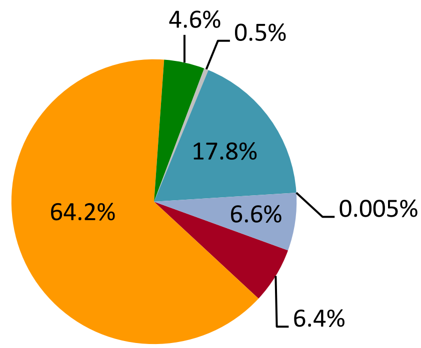
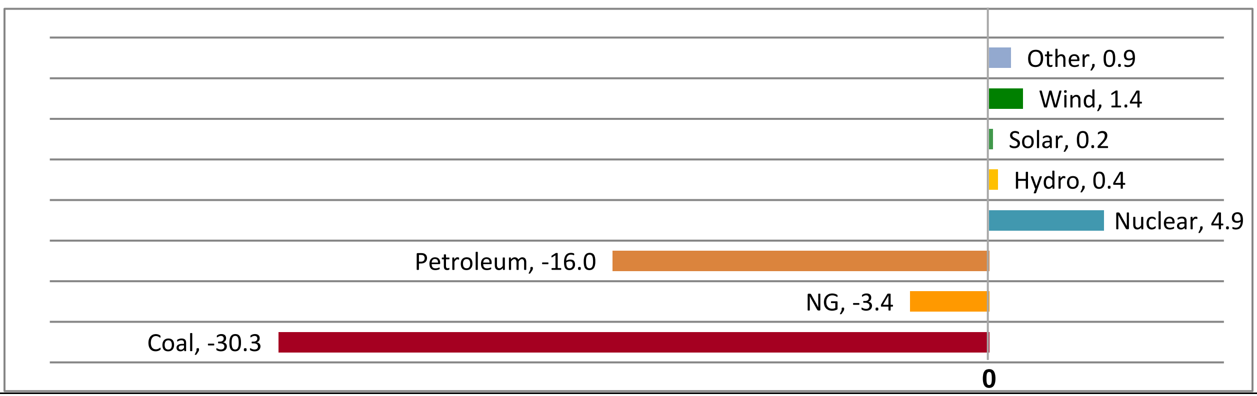


Exhibit 2-5 Cumulative change (GW) of the generation mix for 2014-2025[17]



Source: NETL using Ventyx Velocity Suite Generating Unit Capacity Query (2)

Exhibit 2-6 shows a set of snapshots of the generating capacity mix in the Eastern Interconnection between 2014 and 2025. In 2014, 38.3 percent of the 608.5 GW of capacity in the Eastern Interconnection is natural gas-fired, while 33.1 percent is coal-fired. Nuclear is the next largest category, at 13.9 percent.

As MATS takes effect in 2015, the retirement of coal and petroleum-fired units leads to an 11.6 GW reduction in electricity generating capacity in the Eastern Interconnection by 2016. Between 2016 and 2020, there is an additional 6.5 GW reduction in generating capacity.[18]

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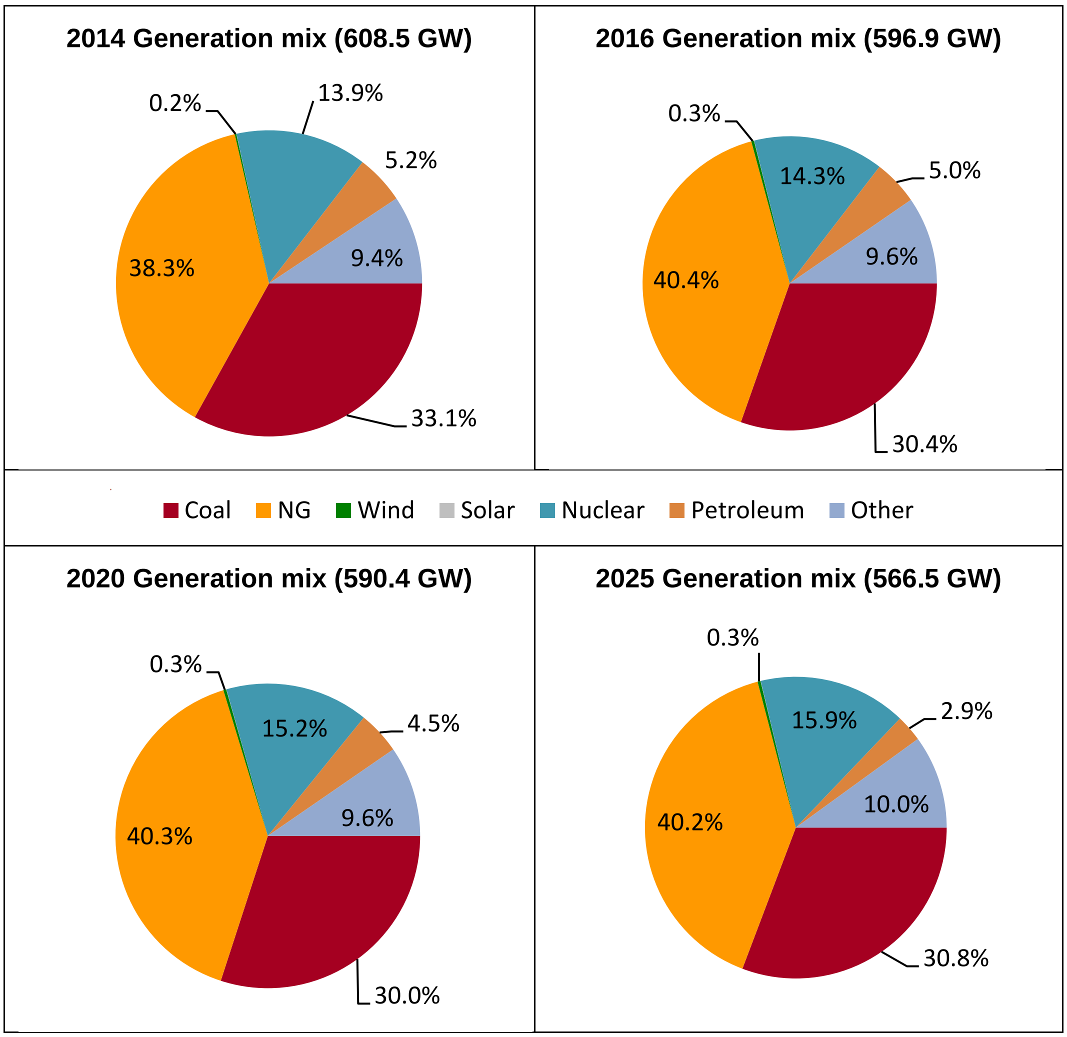
[16] Other new generation includes the addition of hydroelectric (0.38 GW), biomass (0.73 GW), landfill gas (0.05 GW), other (0.86 GW), and renewables (0.01 GW).

[17] Other generation includes the cumulative change of other (0.12 GW), landfill gas (0.05 GW), renewable (0.01 GW), and biomass (0.73 GW).

[18] The cases developed for this report only consider generating capacity that is certain to enter service during the period. Planned-certain units include generating units that are permitted and under construction. New speculative units include generating units that are proposed, pending approval or under a feasibility study.

There is a further reduction in generation between 2020 and 2025 of 23.9 GW. In all, the Eastern Interconnection will lose 3 percent of its capacity by 2020, and 7 percent by 2025. However, capacity additions beyond the 2020 period are speculative at this point and may not occur, thus they are excluded from this report. Some of this lost capacity may be made up by units which are listed as Speculative in the queue, or which have not yet been placed into the queue. Despite the net losses in fossil fuel-fired generation, by 2025 they still make up the bulk of generating capacity. Between 2014 and 2025, natural gas-fired generation's contribution to the generation mix increases by roughly 2 percent, while petroleum- and coal-fired generation's contribution each decrease by about 2 percent.

Exhibit 2-6 Eastern Interconnection fleet capacity profile (%) for 2014-2025 period[19]

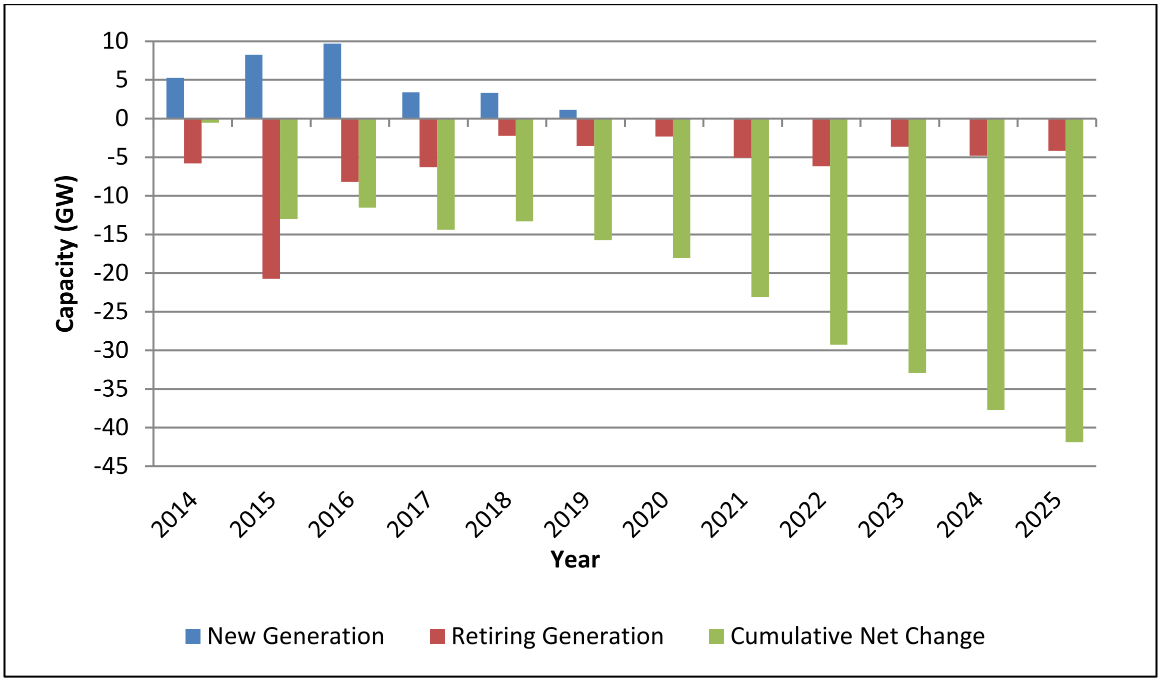


Source: NETL using Ventyx Velocity Suite Generating Unit Capacity Query (2)

[19] Capacity in service on December 31 for each profiled year.

Exhibit 2-7 shows the annual capacity additions and retirements from 2014-2025 in the Eastern Interconnection. As shown, most capacity additions occur before 2017, after which they taper off until 2020. This reflects the timeline for constructing new plants once they have progressed enough to be considered Certain Capacity. In contrast, following the 2015 spike, retirements are projected to continue steadily throughout the period, as aging plants are taken offline.

Exhibit 2-7 Eastern Interconnection capacity changes (2014-2025)

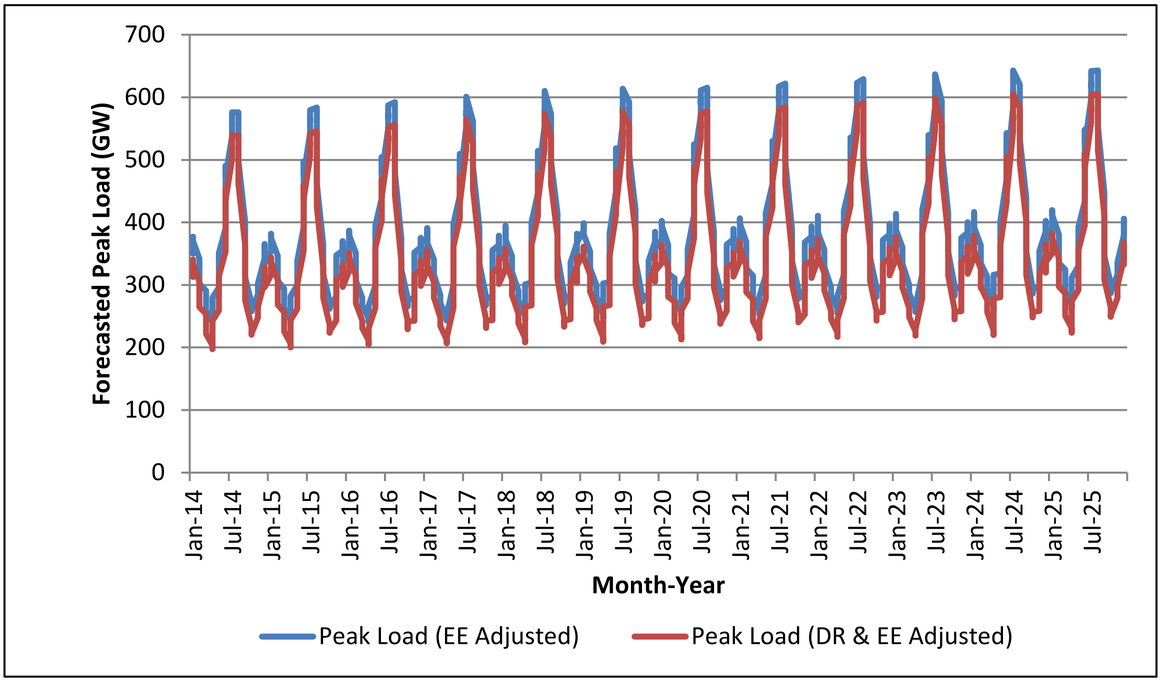


Concurrent with the loss of generating capacity due to retirements, the Eastern Interconnection peak load is expected to increase by 10 percent across the projected period. Forecasted peak load, as shown in Exhibit 2-8, spikes during the summer months (June through August) when demand is at its highest; however, callable DR can reduce peak summer loads by an average of 6 percent across the interconnection when necessary through 2025, if all DR fully responds when called. (16)[20]

The combination of expected load increases and net generation losses puts the Eastern Interconnection in a precarious situation where capacity additions will be required to replace retiring capacity and to meet demand increases over the next decade. The following section describes these requirements and quantifies some of the potential impacts of this situation.

[20] The NERC regions comprising the Eastern Interconnection all operate various demand response programs that incentivize the reduction of electricity demand during peak demand periods. Due to FERC Order 745 being vacated on May 23, 2014, however, the market rules of the RTOs and ISOs within the Eastern Interconnection may change, resulting in lower DR participation rates.

Exhibit 2-8 Eastern Interconnection monthly load profile (2014-2025)[21]



3 Findings

This section discusses the results from the two modeled cases, Retirements and No-Retirements, in regards to pricing impacts, capacity shortfalls, and generation and emissions profiles. Section 3.1 examines the projected effects of the two cases on on-peak locational marginal prices (LMP), as well as annual and seasonal costs of demand. Section 3.2 discusses the projected impacts on the Eastern Interconnection's operating reserve margins and ability to meet peak demand. Section 3.3 shows the expected changes in generation dispatch, capacity factors, and fuel consumption under each case. Finally, Section 3.4 describes the projected emissions profile of the two cases modeled.

3.1 Pricing

Peak and off-peak electricity pricing was explored in each case through 2025. As will be shown throughout this section, peak pricing in the Retirements case is exacerbated by the type and quantity of capacity available during peak periods, resulting in electricity prices that are up to 40 percent higher (for on-peak summer demand) than the prices projected in the No-Retirements case.

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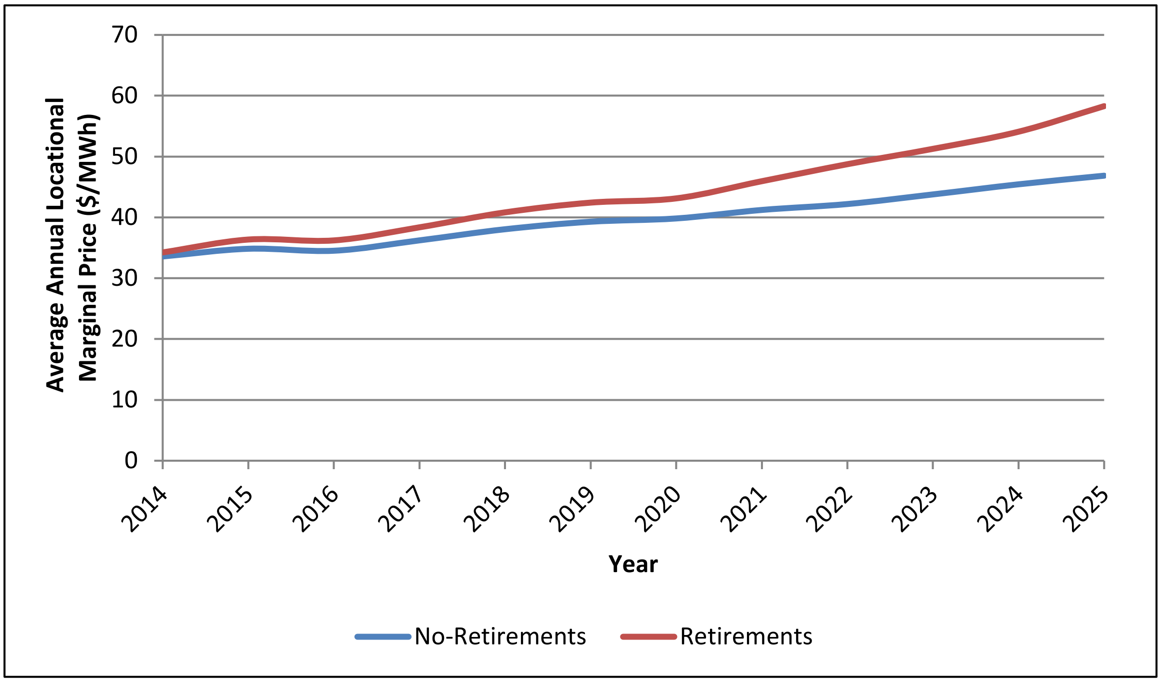
[21] Peak load in both cases is adjusted for reductions in electricity use expected due to projected impacts from Energy Efficiency (EE) and conservation programs.

3.1.1 Locational Marginal Pricing[22]

Approximately 98.6 GW of retirements from thermal power generation units in concert with an increase in demand over the study period will cause a sharp increase in average on-peak[23] electricity prices within the Eastern Interconnection in the Retirements case, as shown in Exhibit 3-1. In the No-Retirements case, price increases are solely the result of demand growth, whereas in the Retirements case, prices increase further based on the type and availability of remaining generation, which is discussed further in Section 3.1.3. For both the No-Retirements and Retirements cases, average on-peak electricity prices are projected to increase by 40 percent, from \$33.6/MWh to \$46.9/MWh, and 70 percent, from \$34.2/MWh to \$58.3/MWh, respectively, from 2014 to 2025.

Exhibit 3-1 Eastern Interconnection average annual on-peak LMP (2014-2025)



3.1.2 Annual Costs of Demand[24]

Exhibit 3-2 and Exhibit 3-3 show the on-peak and off-peak[25] costs of electricity for the No-Retirements and Retirements cases, respectively. The cost of electricity to meet both on-peak and off-peak demand is higher in the Retirements case than in the No-Retirements case with the maximum annual cost reaching approximately \$150 billion in 2025 compared to approximately \$120 billion in the No-Retirements case, from a starting point of nearly \$60 billion in 2014.

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[22] For this report, locational marginal pricing is defined as the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received. The delivery/receiving point is considered to be the entirety of the Eastern Interconnection.

[23] On-peak is defined as weekdays, except NERC holidays, from the hour ending at 8:00 a.m. until the hour ending at 11:00 p.m.

[24] $Cost\ of\ Demand = \sum_1^{8760} LMP_i * D_i$, where D is demand.

[25] For this report, off-peak is defined as all NERC holidays and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 7:00 a.m.

Thus, the cost of demand under the Retirements case rises 50 percent more than under the No-Retirements case. Described another way, the total cost of producing 2.8 billion MWh supplied to meet 2025 demand in the Eastern Interconnection is $150 billion in the Retirements case, equivalent to an average electricity production of $53.57/MWh.

Breaking these down to on-peak and off-peak costs, the annual on-peak cost of demand increases by $36.8 billion in the No-Retirements case and $62.8 billion in the Retirements case. The annual off-peak cost of demand increases by $12.5 billion and $14.8 billion in the No-Retirements and Retirements cases, respectively.

Exhibit 3-2 Annual cost of electricity demand in No-Retirements case (2014-2025)

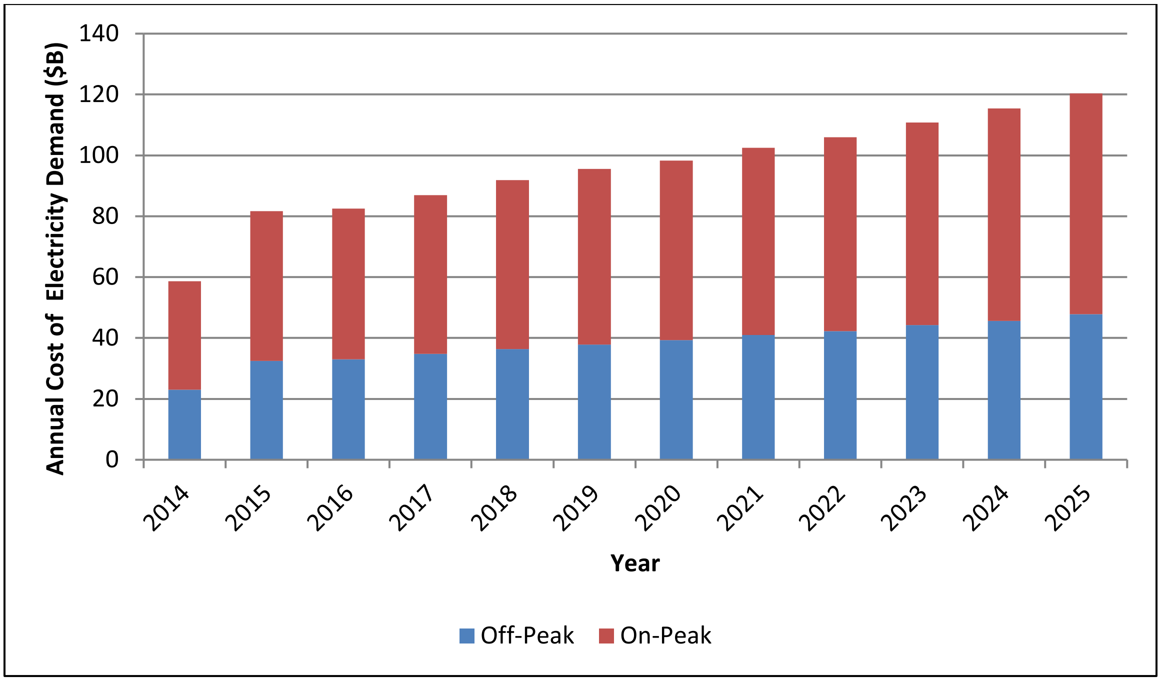
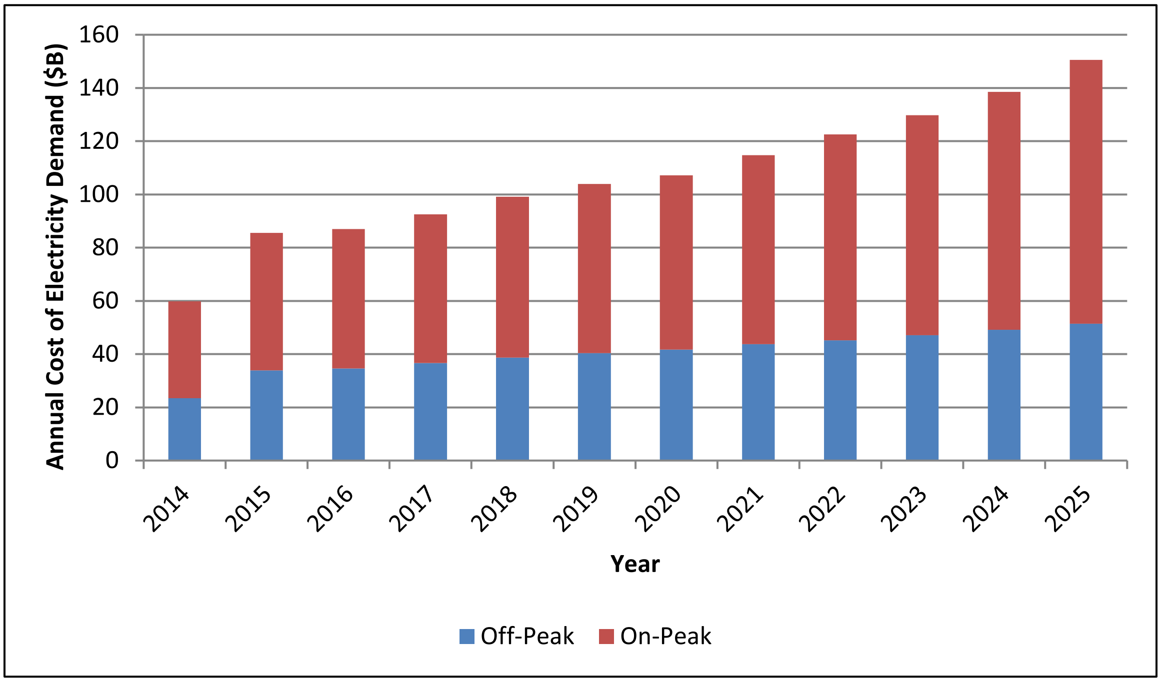


Exhibit 3-3 Annual cost of electricity demand in Retirements case (2014-2025)



3.1.3 Seasonal Costs of Demand[26]

Further examining the apportionment of annual electricity costs between the two cases, it becomes apparent that a large portion of the increased cost of meeting annual demand in the Retirements case can be attributed to increased peak prices in the summer months.

When comparing the cost of annual on-peak and off-peak demand for the summer months (Exhibit 3-4 and Exhibit 3-5) to the annual cost of electricity, the summer months are 47 percent of the total on-peak and off-peak costs in 2025 in the No-Retirements case. Summer peak is approximately 56 percent of the total on-peak and off-peak costs in 2025 in the Retirements case. As seen when comparing the two cases for the annual cost of electricity demand, the Retirements case has a higher cost with the maximum of both on-peak and off-peak reaching $83.6 billion compared to $56.8 billion in the No-Retirements case due to utilization of higher cost capacity to meet demand in the Retirements case.

[26] $Cost\ of\ Demand = \sum_{1}^{8760} LMP_i * D_i$, where D is demand. Calculation followed NERC planning seasons.

Exhibit 3-4 Cost of annual summer demand in No-Retirements case (2014-2025)

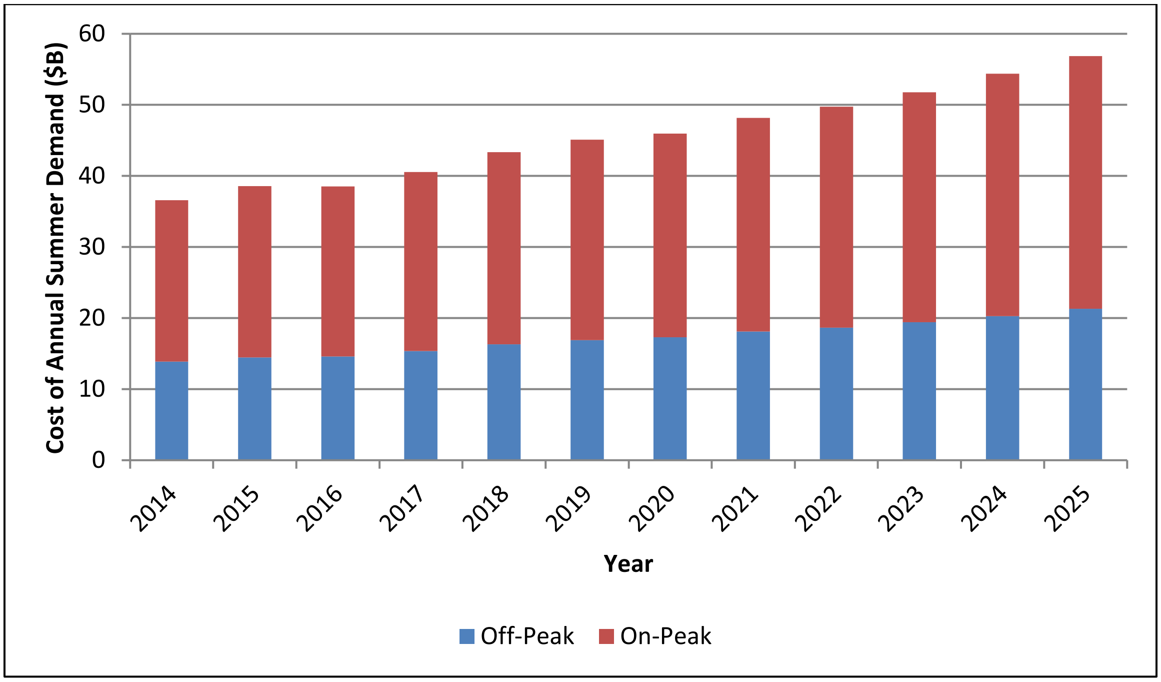
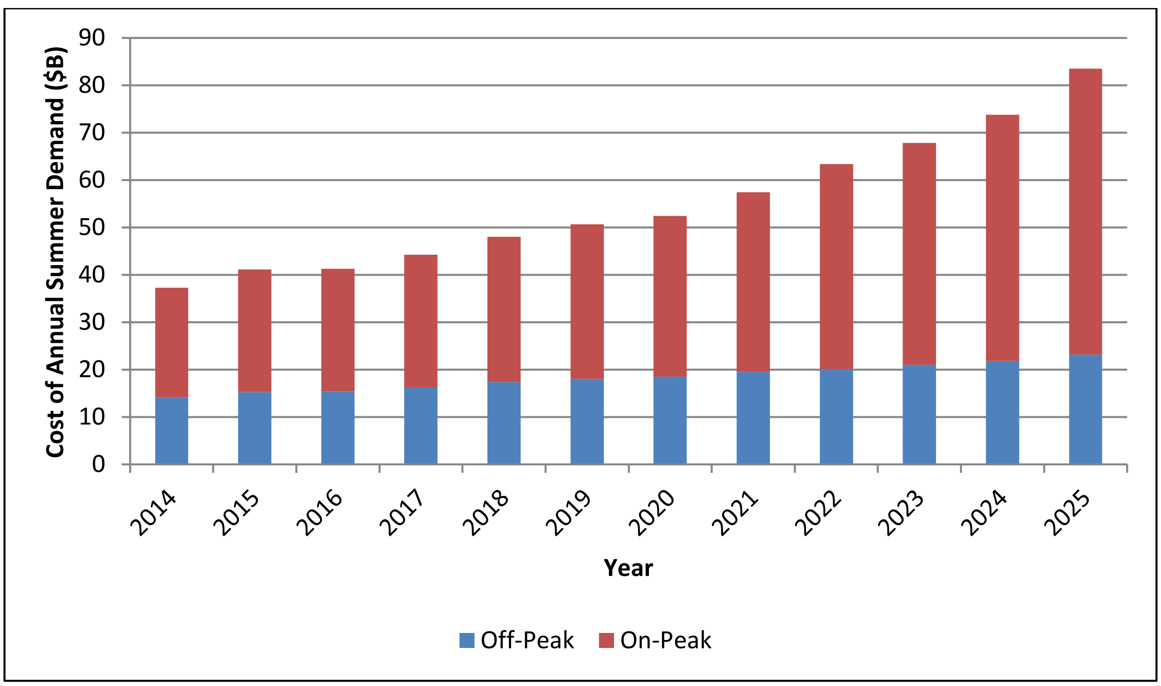


Exhibit 3-5 Cost of annual summer demand in Retirements case (2014-2025)



3.2 Capacity

NERC assigns an annual planning reserve margin for each of its subregions, which it uses as an indicator of whether capacity additions are keeping up with demand growth. (12) The reserve margin is the difference between available capacity and peak demand. The planning reserve margin is the reserve margin targeted by NERC as necessary for maintaining a reliable bulk power system: a "cushion" to ensure that the system can meet peak demand in the face of unexpected outages, extreme weather conditions, or other challenges.[27]

The NERC subregions within the Eastern Interconnection have annual planning reserve margins that range from 11 to 20 percent for the 2014-2015 period. NERC does not maintain a target reserve level for the Eastern Interconnection as a whole. Using a load weighted average of these levels to create a composite measure for the entire interconnection produces a reserve level of 15 percent. (12)

Throughout the projection period, it is expected that the Eastern Interconnection will increasingly rely on imports from Canada to meet peak demand. In both the No-Retirements and Retirements cases, the Eastern Interconnection will require an increasing amount of imports to meet peak demand each year starting in 2014, with most of the imports supplied from Canada to MISO. In both cases, MISO and ISO-NE would reach their tie line capacity limits for imports.

In each case, it should be underscored that only Certain Capacity additions from the queue are accounted for in meeting reserve requirements and peak demand. If Speculative Capacity moves forward and becomes certain, it could reduce the need for incremental capacity, although based on analyses from the 2011 FERC RTO/ISO Metrics Report, (4) some capacity is still likely to be needed. This is described in more detail in Section 3.2.2.

3.2.1 Operating Reserve Margin

Exhibit 3-6 shows the monthly Eastern Interconnection reserve margins for both cases through 2025. As shown, the Eastern Interconnection is expected to experience decreasing reserve margins across the period in this report in both cases. In the Retirements case, coincident reserves are projected to drop below the NERC targeted planning reserve level of 15 percent by the 2021 summer peak, and continue to drop, reaching eight percent in late July 2025. Reserves will never fall below the NERC targeted planning reserve level in the No-Retirements case.

Unless sufficient Certain Capacity becomes available in the future, beyond that included in the simulations modeled in this report, coincident Eastern Interconnection reserve levels can be expected to fall below the planning reserve level annually during peak demand periods by an increasing amount. While it is highly unlikely that market prices would fail to incentivize new generation, periods of low or zero capacity margin projected in this modeling underscore the magnitude and period of new capacity additions required. Because new capacity will be needed within a short period, generation that can go through planning, siting, and construction relatively quickly, such as natural gas-fired plants, would be favored over generation with longer lead times.

For comparison against the modeled cases, Exhibit 3-6 also shows projections from NERC's LTRA[28] for the summer months of 2014, 2018, and 2023 as well as the 2014-2015, 2018-2019, and 2023-2024 winter months. (12) In summer 2023, the LTRA predicts a 13 percent reserve

[27] For more information on reserve margins, see NETL's Power Market Primers, available at: http://netl.doe.gov/research/energy-analysis/publications/details?pub=2bd05cd5-38fd-45ee-81e4-10b33c71018a.

[28] The LTRA is published annually and provides projections of capacity and peak demand over a ten-year period for every subregion within NERC.

margin, which is lower than the NERC targeted reserve level, but marginally higher than the 12.2 percent projected in the Retirements case (see detailed look in Exhibit 3-7). Throughout the projection, reserve margin levels in the No-Retirements case remain above the NERC planning reserve level, reaching a low reserve level of 17.1 percent in 2025.

Exhibit 3-6 Eastern Interconnection operating minimum monthly reserve margin (2014-2025)

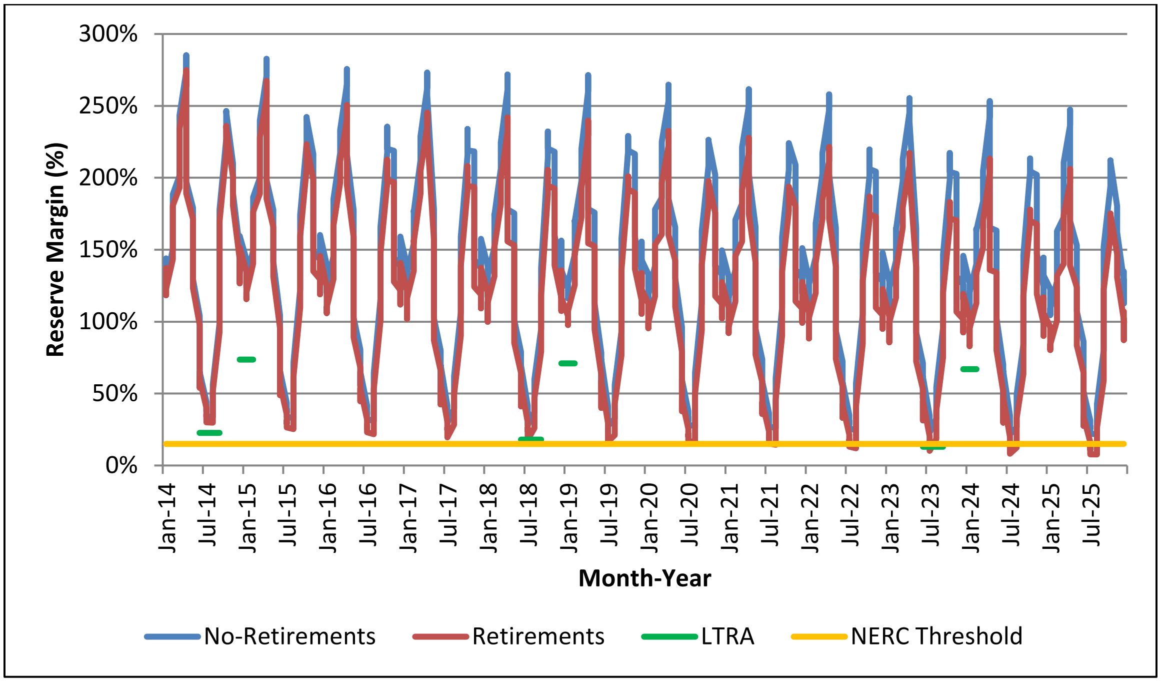
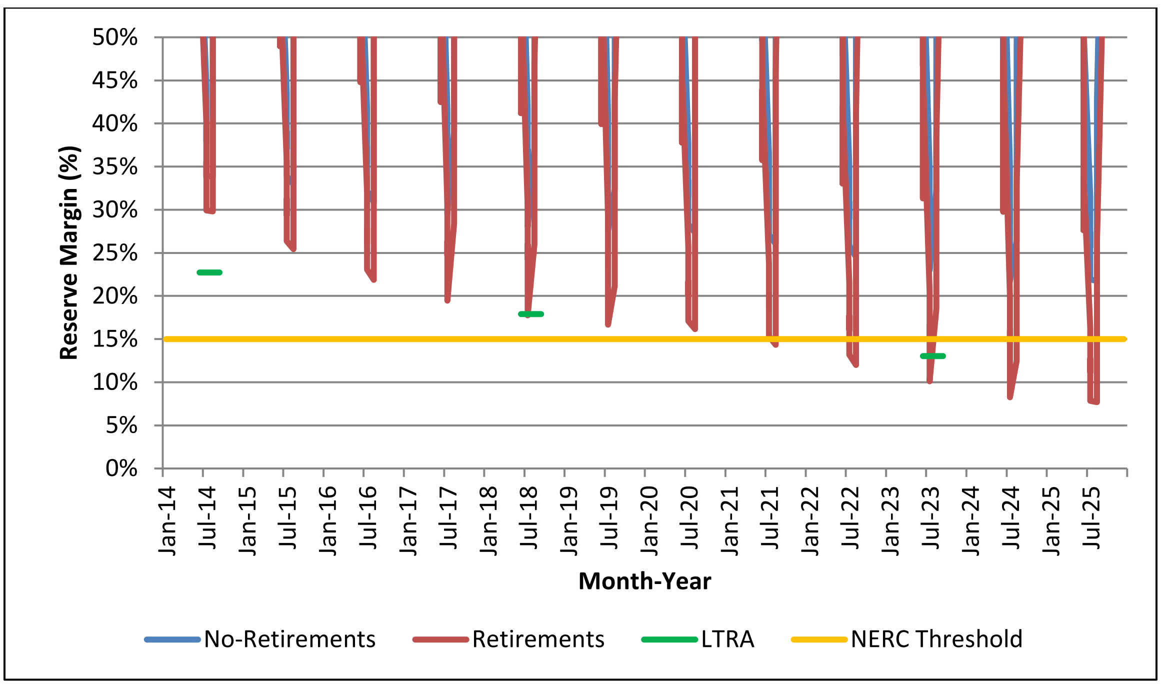


Exhibit 3-7 Eastern Interconnection operating minimum monthly reserve margin – detailed look (2014-2015)



3.2.2 Generation Shortfall

Although the Eastern Interconnection will suffer a net loss of nearly 50 GW of generating capacity from 2014 to 2025, sufficient generation will be online to meet peak demand through 2019 as indicated in Exhibit 3-8. Beginning in 2020, however, additional generation will be required to meet peak demand when considering generation retirements.[29,30] Incrementally, this additional generation needed, or generation "shortfall," projected by the model will sum to 15.9 GW by 2025, exceeding the net generation lost to retirements over the period.

In addition to meeting peak demand, the Eastern Interconnection is also required to maintain an additional capacity reserve to meet NERC reliability planning requirements. Exhibit 3-9 shows the incremental capacity required on an annual basis that is needed to meet these requirements; through 2025, this capacity totals 44.2 GW, which is in addition to the generation needed to meet peak demand.[31] Comparatively, the combined generation queues in the Eastern Interconnection currently include 111 GW of Certain[32] and Speculative Capacity with in-service dates between 2014 and 2025. (17) However, according to the FERC 2011 RTO/ISO Performance Metrics Report[33], (4) only 12-15 percent of projects within the queue ultimately result in an operating plant, meaning that the likely generation total is between 13 and 17 GW. This may or may not be sufficient to fulfill the incremental generation needed to meet demand. Without retirements, the Eastern Interconnection would not expect any additional generation needs to meet peak demand or NERC planning requirements.

[29] Generation required to satisfy peak demand was calculated by balancing the quantity of generation and the peak system demand on an annual basis. The incremental values were determined by netting the annual requirement with the incremental sum for each preceding year. It is critical to note that the dispatched shortfall capacity did not exist within the model, but was created by the model to balance load and generation. In reality, peak demand shortfall capacity may represent Speculative Capacity that will be certain and in service by 2020, but is not included in the current model because it is has not reached certainty.

[30] Although interconnection level reserve margins never fall below 0 percent, meaning that there is an interconnection level generation shortfall, internal transmission constraints create localized shortfalls within the component areas. Because the system is highly integrated, a shortfall in one area that creates a loss-of-load situation has the potential to create a cascading loss-of-load across the interconnection if improperly managed, such as occurred during the Northeast Blackout of 2003.

[31] Generation required to satisfy the NERC reliability planning requirements was calculated by determining the quantity of generation required to raise the minimum annual reserve margin to planning requirement via backward calculation through the NERC reserve margin calculation, i.e., Generation Required = [(NERC planning requirement – Minimum Annual Reserve Margin)*Net Internal Demand] – Net Internal Demand, where Net Internal Demand = Total Internal Demand – Dispatchable, Controllable Demand Response. (12)

[32] In this instance, certain generation includes both existing-certain and planned-certain generation.

[33] On August 26, 2014, FERC released an information request under Docket AD14-15-000 to receive new data to provide an update to this report to cover 2008 through 2014.

Exhibit 3-8 Required generation to meet peak demand (2014-2025)

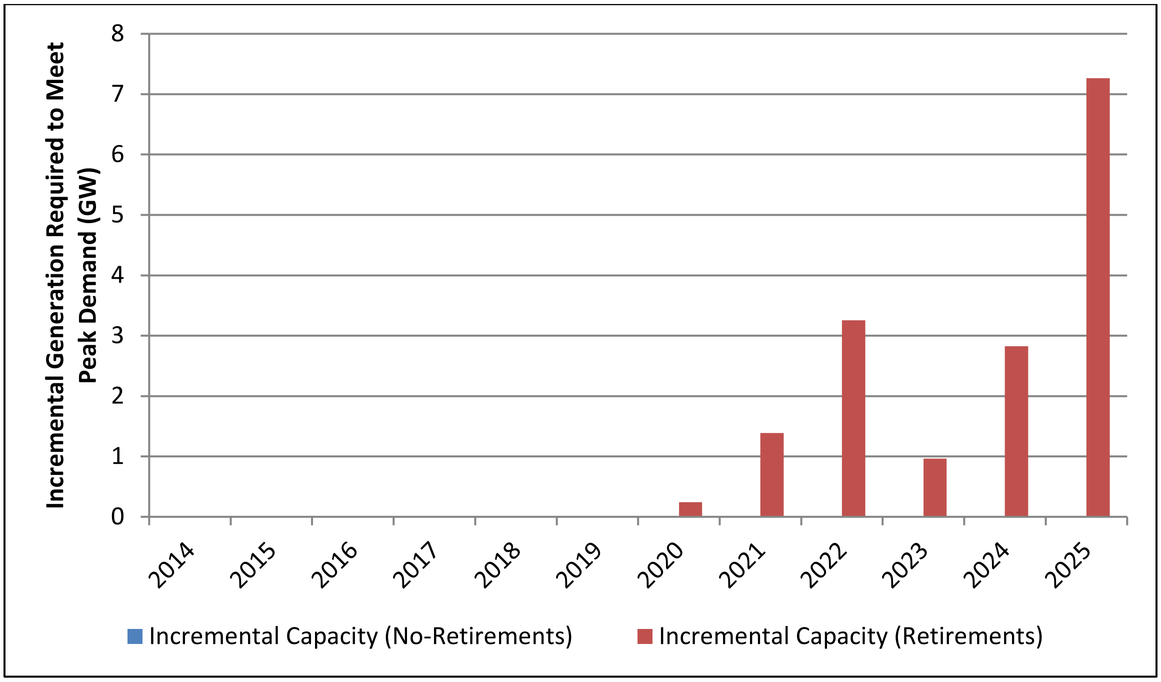
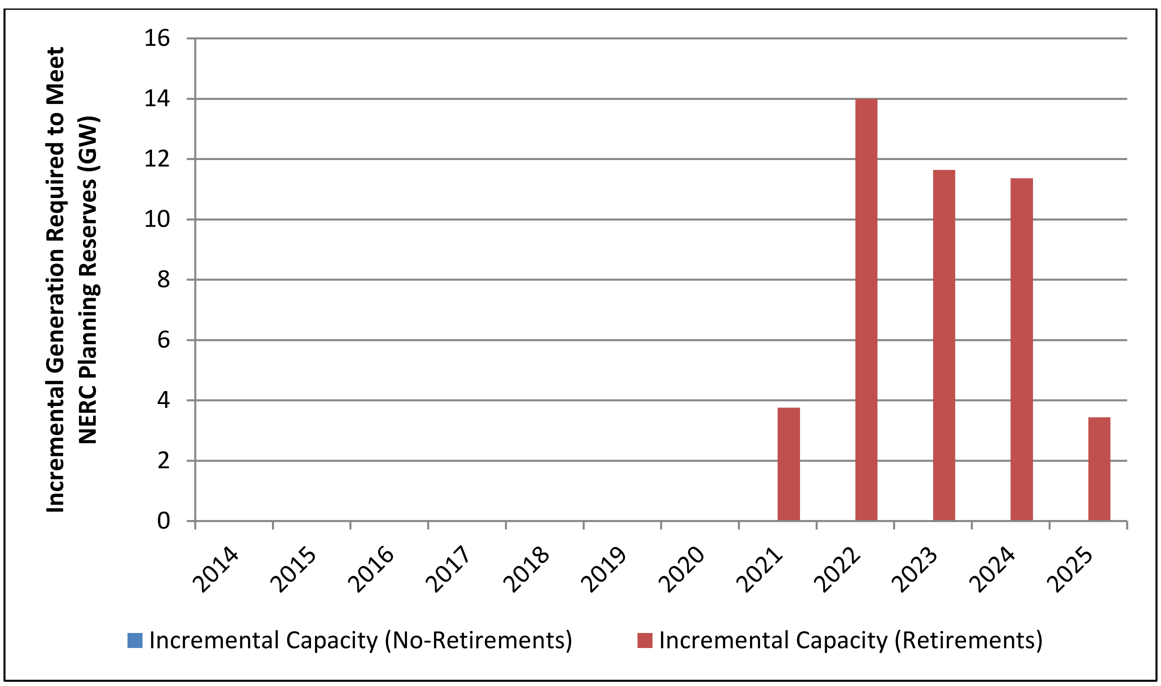


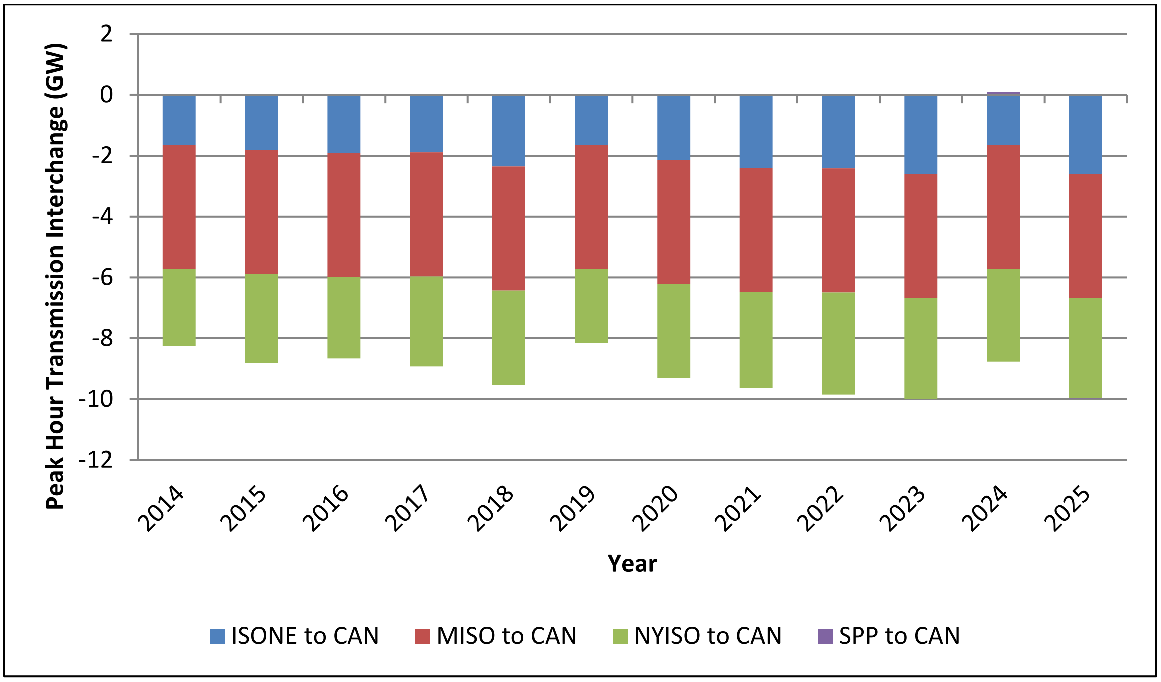
Exhibit 3-9 Additional Eastern Interconnection generation required to meet NERC planning reserve requirements (2014-2025)



3.2.3 Transmission Needs

Throughout the projection period, it is expected that the Eastern Interconnection will increasingly rely on imports from Canada to meet peak demand. In the No-Retirements case, as shown in Exhibit 3-10, the Eastern Interconnection will require an increasing amount of imports to meet peak demand each year starting in 2014, with most of the imports supplied from Canada to MISO. Even though the majority of the peak hour transmission interchange will be imports, SPP will export a small amount (less than 1 GW) to Canada in 2024. Eastern Interconnection peak hour imports were simulated to reach a maximum of 10 GW in 2025, with 41 percent coming to MISO from Canada. [34,35,36]

Exhibit 3-10 Eastern Interconnection summer peak capacity interchange in No-Retirements case (2014-2025)



As in the No-Retirements case, the Eastern Interconnection will increasingly rely on transmission imports to meet peak demand in the Retirements case, as shown in Exhibit 3-11. Both cases increase imports from approximately 8 GW to 10 GW. Comparing 2014 and 2025, peak imports will increase slightly less, 20.6 percent, than peak imports in the No-Retirements case, 20.8 percent. However, peak imports under the Retirements case actually peak in 2023, at 10.3 GW, which is slightly more than the peak of 10.0 GW in the No-Retirements case. As in the No-Retirements case, the majority of imports in the Retirements case will be from Canada to MISO (40-55 percent from 2014-2025). Even though MISO will be receiving imports from

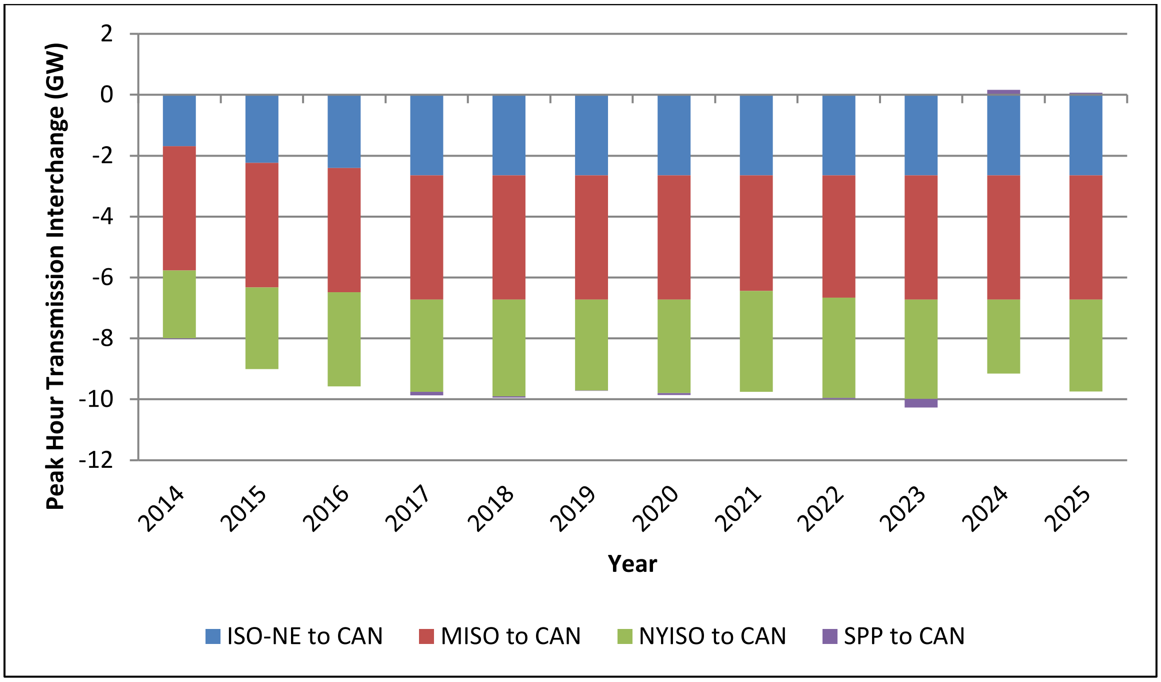
[34] The transmission results of the model consider the inter-area interchange limits as defined by the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group. (20) These limits, however, are based on physical system conditions and do not account for reductions placed on the system by operators or regulatory requirements. For example, PJM has placed an artificial 6,500 MW capacity import limit on its system for the 2017/18 capacity market year in an effort to reduce the risk that cleared imports may be curtailed by transmission system operators outside of PJM. (18)

[35] Positive interchange represents exports from the Eastern Interconnection, while negative interchange represents imports to the Eastern Interconnection.

[36] The analysis performed to determine the amount of imports and exports to and from the Eastern Interconnection in the No-Retirements and Retirements cases does not include fuel requirement estimates for incremental generation required to meet demand or NERC planning reserve requirements. It accounts for existing and anticipated transmission interchange limits; i.e., transmission is considered prior to shortfall generation.

Canada, they will reach their tie line capacity limit, which could have the potential to create reliability issues. MISO has previously stated that under announced retirements their system will experience a 5-7 GW capacity shortfall in 2016/2017, meaning that wheel-through imports, which pass through MISO to reach load beyond it, may be consumed within MISO rather than at their intended destination. (5) ISO-NE will also reach its tie line capacity. In the Retirements case, imports to SPP will be seen more throughout the projection, and SPP will export to Canada in 2024 and 2025. Most of the difference between the two cases in 2023 can be attributed to imports from Canada to SPP under the Retirements case.

Exhibit 3-11 Eastern Interconnection summer peak capacity interchange in Retirements case (2014-2025)



3.3 Generation

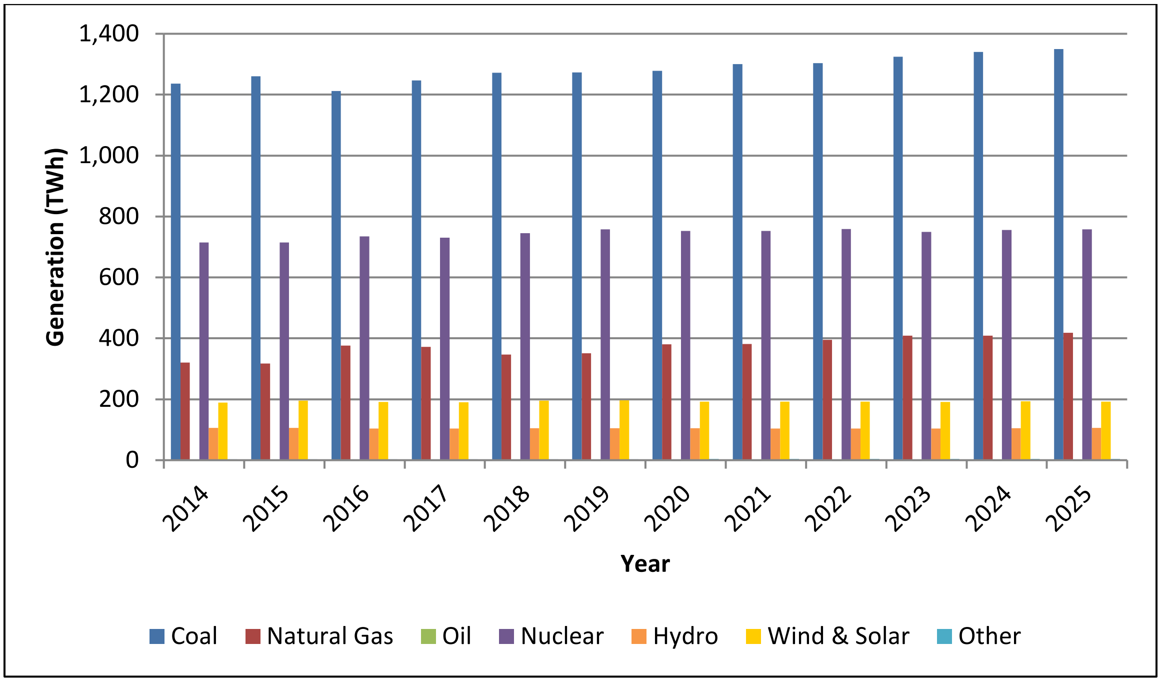
As shown in Exhibit 3-12 and Exhibit 3-13 below, although available capacity would differ under the Retirements and No-Retirements cases, generation dispatch remains fairly consistent. Under both cases, coal-fired and nuclear generation continue to service the majority of the Eastern Interconnection's loads, with nuclear continuing to operate at high capacity factors and coal plants dispatching more. In the Retirements case, remaining coal plants increase their capacity factors by a greater extent to offset generation lost from retiring plants. Generation from coal also grows in both cases, although the growth is more modest in the Retirements case: 4 percent compared to 9 percent in the No-Retirements case. Natural gas also grows more under both cases, although the increase is greater under the Retirements case.

Under the No-Retirements and Retirements cases, coal consumption increases by 17 percent and 7 percent, respectively. Natural gas consumption shows a more dramatic rise – by 32 percent under the No-Retirements case and 56 percent under the Retirements case.

3.3.1 Generation Profile

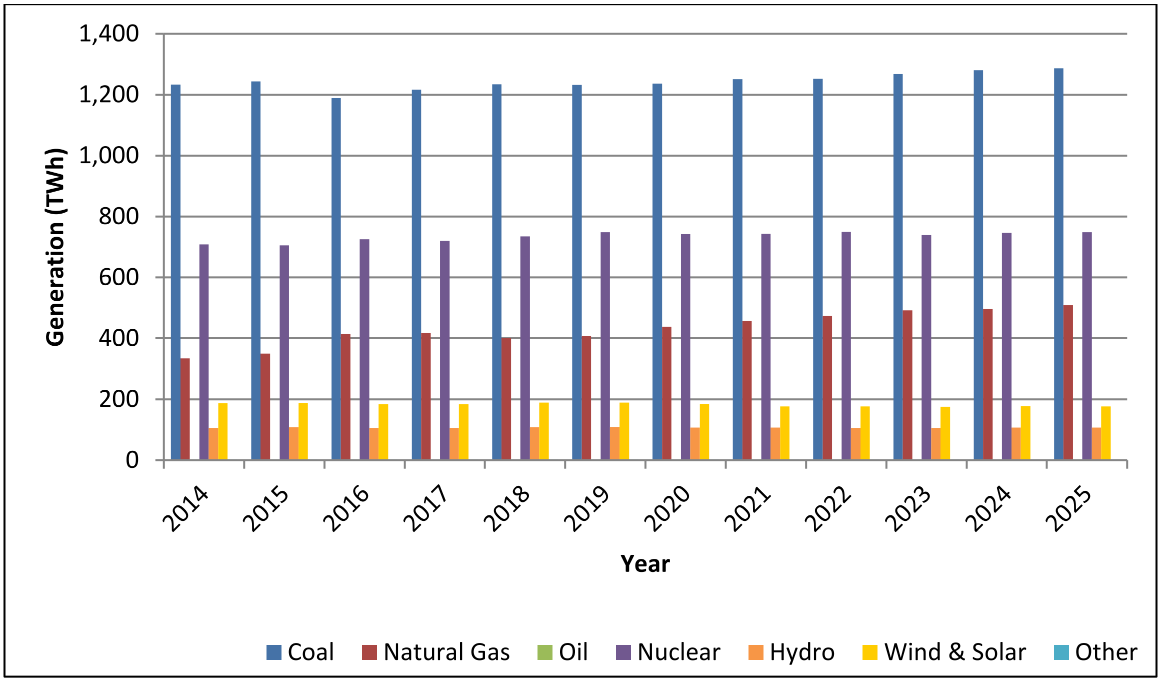
As shown in Exhibit 3-12, coal-fired and nuclear generation will service the majority of the Eastern Interconnection demand each year, on a tera-watt hour (TWh) basis, in the No-Retirements case with over 47 percent from coal and over 27 percent from nuclear. Over the projected period, natural gas-fired generation is projected to provide about 12-15 percent of demand, which is more than the combined contributions of wind and solar, hydroelectric, petroleum-fired, and "other" generators. Coal-fired contributions will increase across the projection, by 9 percent overall, but experience a slight decrease in 2016. Natural gas-fired contributions will see slight decreases in certain years, but overall will rise from 320 TWh to 418 TWh over the 2014-2025 period. Nuclear generation will also increase slightly, from 714 TWh to 759 TWh, while hydroelectric and wind and solar generation remain consistent.

Exhibit 3-12 Eastern Interconnection generation by fuel type in No-Retirements case (2014-2025)



The Retirements case is consistent with the No-Retirements case, in that coal-fired and nuclear generation will continue to service the majority of the Eastern Interconnection's load, even after generation retirements reduce the amount of coal-fired capacity in the system – coal's contribution to load service is reduced by approximately 3 percent, from 48 to 45 percent, as shown in Exhibit 3-13. Natural gas generation will provide up to 18 percent by 2025, while nuclear will contribute 26 percent. Natural gas generation will increase across the projection period, from 334 TWh in 2014 to 508 TWh in 2025, while hydroelectric and wind and solar generation remain consistent. As in the No-Retirements case, nuclear generation will increase slightly, from 705 TWh in 2014 to 749 TWh in 2025. Coal-fired generation will fluctuate, reaching a low of 1,189 TWh in 2016, and then experience an overall increase to 1,287 TWh in 2025. Therefore, even in the face of MATS, coal-fired generation will both increase and remain the dominant source of electricity generation in the Eastern Interconnection through 2025.

Exhibit 3-13 Eastern Interconnection generation by fuel type in Retirements case (2014-2025)



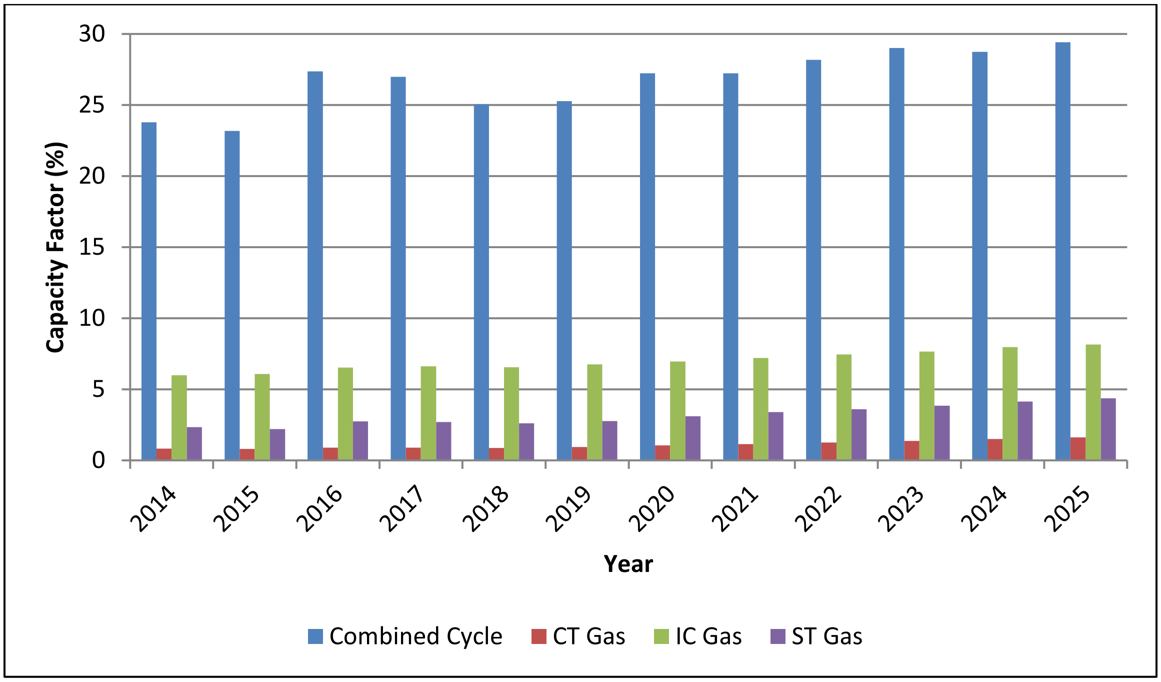
3.3.2 Capacity Factor Changes

3.3.2.1 Annualized Capacity Factor Changes

Annualized capacity factors for natural gas-fired generation increase under both cases, although to a greater extent under the Retirements case. Annualized capacity factors for steam coal units also increase under both cases, and similar to natural-gas fired generation, more under the Retirements case. Similarly, weekly capacity factors for both steam coal- and natural gas-fired generation increase across the period under both cases, although the increase is greater under the Retirements case.

In the No-Retirements case, shown in Exhibit 3-14, capacity factors for all types of gas-fired generation increase during the projected period. Capacity factors for combined cycle generation, the most utilized form of gas-fired generation, increase from 23.8 percent in 2014 to 29.4 percent in 2025. Other forms of gas-fired generation, which are mainly used as peaking capacity, are expected to have slightly increased capacity factors, from between 0.8 and 6 percent in 2014 to between 1.6 and 8.2 percent in 2025. The growth in the capacity factors of each of these unit types is a direct result of the anticipated 10 percent load growth simulated in the model during the projected period.

Exhibit 3-14 Eastern Interconnection fleet capacity factors for gas-fired generation in No-Retirements case (2014-2025)

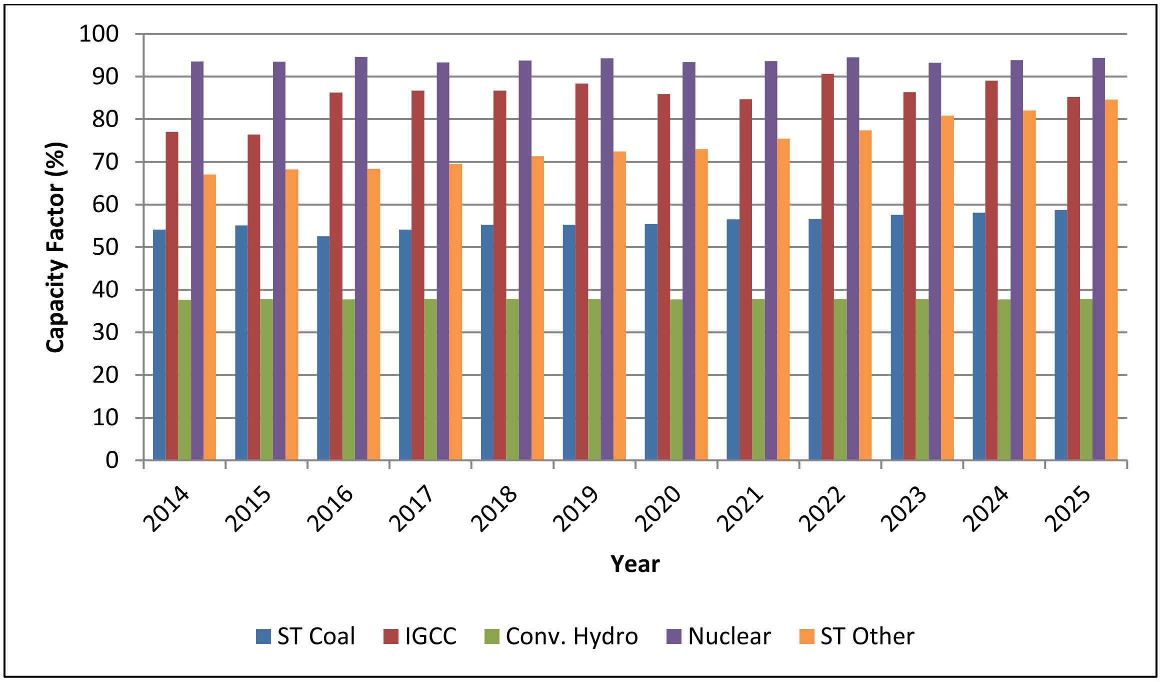


Under the No-Retirements case, capacity factors for other forms of generation are much higher than for gas-fired units, as shown in Exhibit 3-15. These other types of generation – nuclear, coal-fired, and hydroelectric – are more likely to be used for baseload generation than natural gas. The capacity factor for nuclear units is expected to remain at 93-95 percent across the projection period; similarly, the conventional hydroelectric generation capacity factor will remain near 37 percent.[37] Integrated gasification combined cycle (IGCC) has a fluctuating projected capacity factor of 77-90 percent.[38] Steam coal, the most common type of coal plant, is projected to have a capacity factor that increases from 54 to 59 percent over the 2014-2025 time period, while steam "other" (bio-gas, landfill gas, etc.) is projected to increase from 67 to 85 percent.

[37] This is consistent with the average hydroelectric fleet capacity factor reported from 2008 to 2013 in Table 6.7B of the Electric Power Monthly. (23)

[38] Currently, there is only one IGCC, Edwardsport (618 MW), operating in the U.S. The model includes Edwardsport and a second proposed 580 MW IGCC at Lima, OH, which is proposed to enter service in 2016.

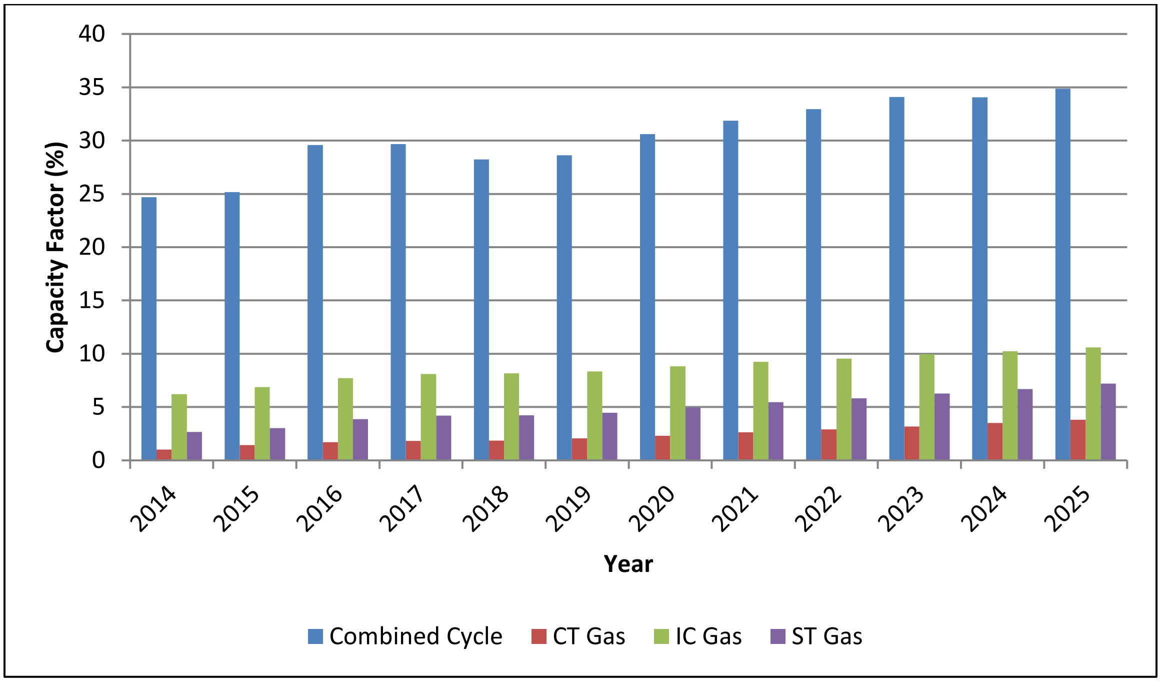
Exhibit 3-15 Eastern Interconnection fleet capacity factors for remaining generation types in No-Retirements case (2014-2025)[39]



As shown in Exhibit 3-16, the Retirements case predicts that capacity factors for gas-fired generation will see a greater increase than predicted in the No-Retirements case. This is consistent with the findings discussed above on the increased share of overall generation from natural gas-fueled plants as coal-fired units retire. The capacity factor for combined cycle generation is projected to increase from 24.7 percent in 2014 to 34.9 percent in 2025. Gas-fired generation used as "peakers" are expected to have increased capacity factors as well, from between 1 and 6.2 percent in 2014 to between 3.8 and 10.6 percent in 2025, depending on the generation type.

[39] Petroleum-fired generation was omitted from Exhibit 3-15 and Exhibit 3-16, because it had capacity factors of less than 1 percent across the projection in both cases.

Exhibit 3-16 Eastern Interconnection fleet capacity factors for gas-fired generation in Retirements case (2014-2025)



Under the Retirements case, capacity factors for most other forms of generation remain much higher than for gas-fired units, despite the increase in gas-fired generation capacity factors, as shown in Exhibit 3-17. These other types of generation – nuclear, coal, and hydroelectric – will continue to be used more to supply baseload generation than natural gas. The capacity factor for nuclear units is expected to remain at 93-95 percent across the projection, as it did under the No-Retirements case; similarly, the conventional hydroelectric generation capacity factor will stay at 37 percent. IGCC has a projected capacity factor of 73-89 percent, which is less than what was predicted in the No-Retirements case. This difference between the simulations is the result of transmission constrained operations caused by retirements, which are amplified in this instance because of the limited number of IGCC units. The capacity factor for steam coal is projected to increase from 57 percent to 67 percent over the 2014-2025 period, a greater increase than that projected under the No-Retirements case. This projected increase in steam coal capacity factors is consistent with the increase projected by the Energy Information Administration in their 2014 Annual Energy Outlook. (15) The capacity factor for the category comprised of “other” (bio-gas, landfill gas, etc.) types of steam generation is also projected to increase from 68 to 90 percent. Exhibit 3-18 shows the Eastern Interconnection’s fleet capacity factors for all generation types for both cases in 2025.

Exhibit 3-17 Eastern Interconnection fleet capacity factors for remaining generation types in Retirements case (2014-2025)

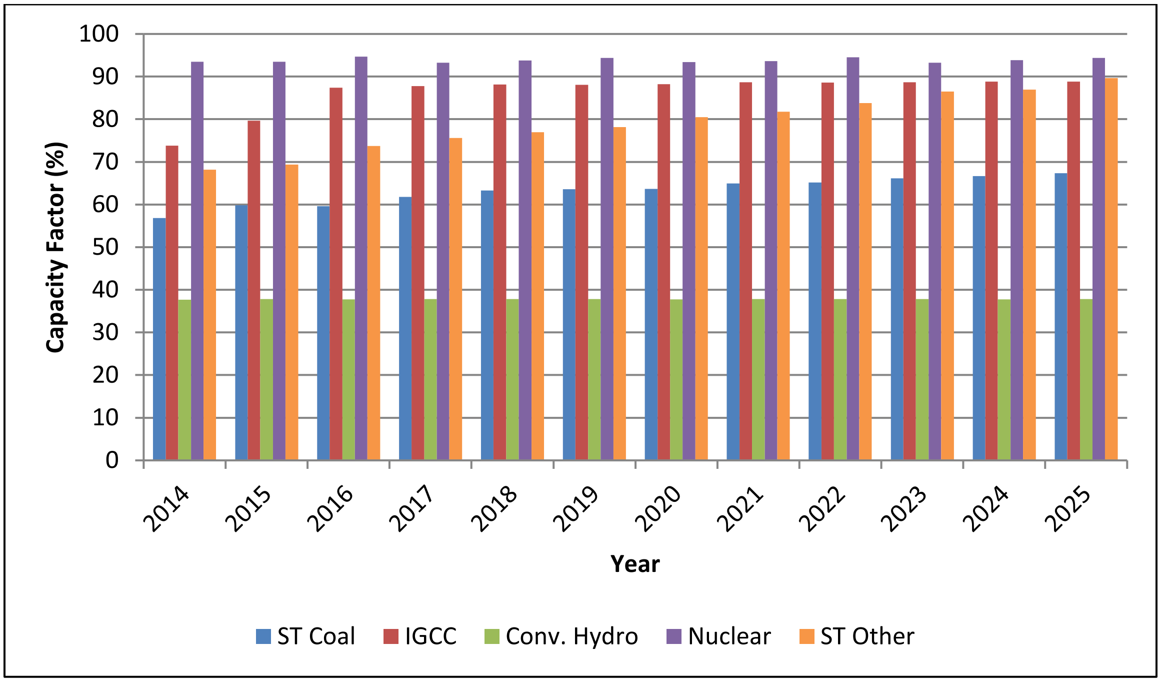
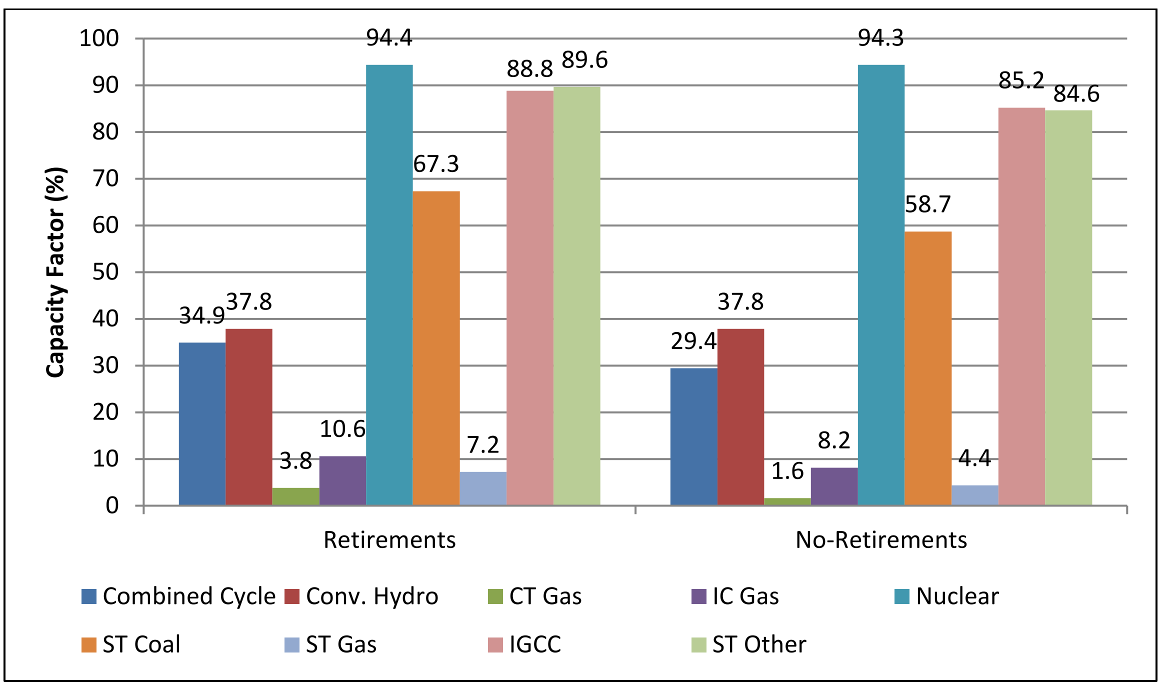


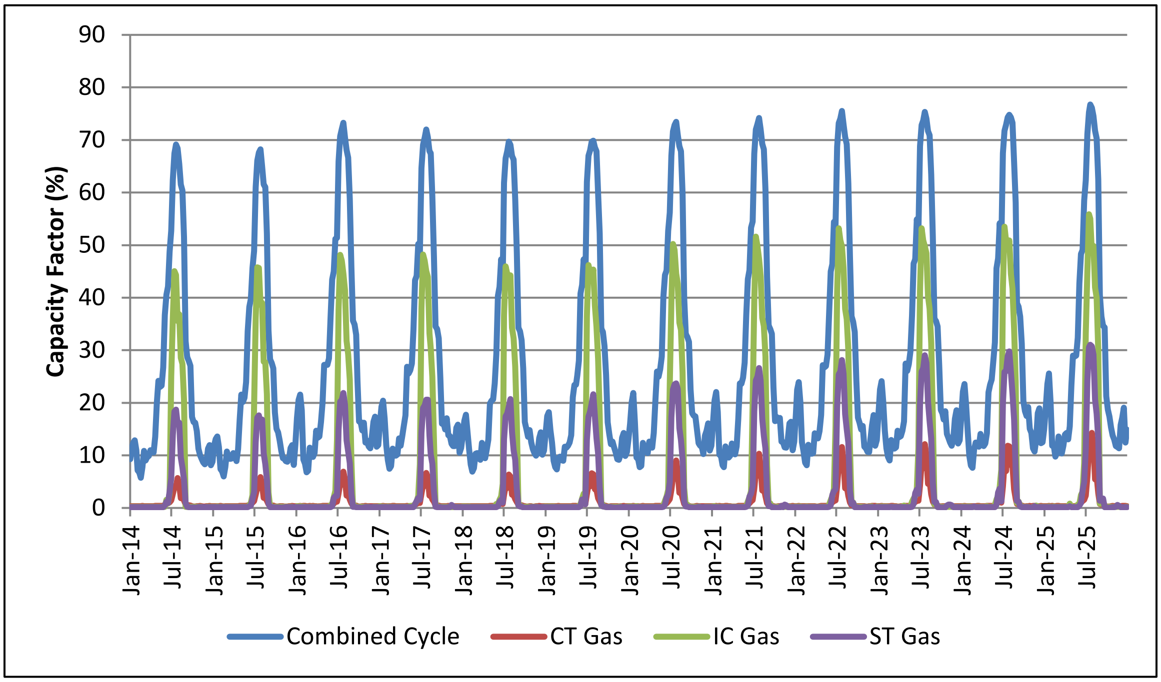
Exhibit 3-18 Eastern Interconnection fleet capacity factors for generation types in both cases for 2025



3.3.2.2 Weekly Capacity Factor Changes

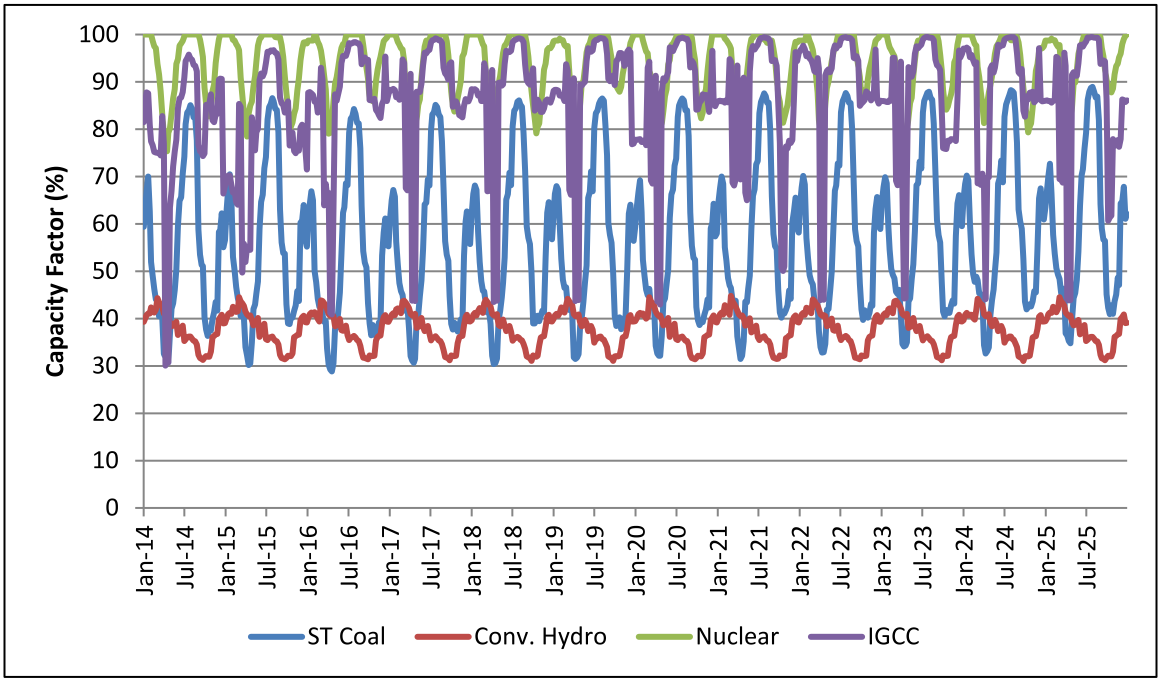
In the No-Retirements case, shown in Exhibit 3-19, capacity factors for all types of gas-fired generation are relatively flat for most of the year, increasing primarily during periods of increased demand. On a weekly basis, capacity factors for combined cycle generation, the most utilized form of gas-fired generation, increase from 6-20 percent during non-peak weeks to 68 percent during the summer peak weeks of 2014 and 76 percent during the summer peak weeks of 2025. Other forms of gas-fired generation, which are mainly used as peaking capacity, also experience similar increases in utilization during summer peak weeks. The growth in the capacity factors of each of these unit types during peak demand weeks is indicative of their utilization as peaking capacity.

Exhibit 3-19 Eastern Interconnection fleet weekly capacity factors for gas-fired generation in No-Retirements case



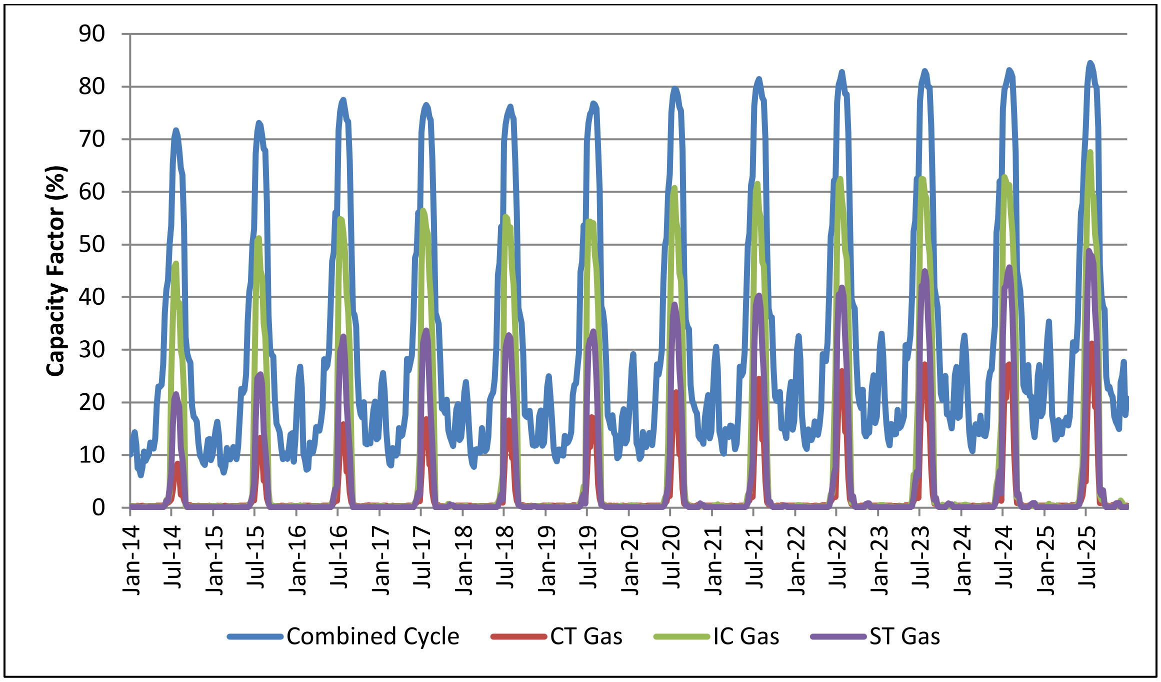
Under the No-Retirements case, capacity factors for other forms of generation are much higher than for gas-fired units, as shown in Exhibit 3-20. These other types of generation – nuclear, coal-fired, and hydroelectric – are primarily used as year-round baseload generation. Petroleum was not included, as its capacity factor remained at 0 percent even during peak weeks. Capacity factor reductions in coal-fired units during non-peak demand periods are directly related to reductions in demand and operational shifting. Reductions in nuclear capacity are related to scheduled refueling outages during the simulation period. The capacity factor for nuclear units is expected to remain near 100 percent across the projection period, although it drops to as low as 75 percent during spring, when most refueling outages are scheduled. Reductions in hydroelectric capacity factors are related to seasonal changes in available potential. Thus, conventional hydroelectric generation cycles between over 40 percent during the early spring to just above 30 percent in late summer. Steam coal, the most common type of coal plant, is projected to shift peak week capacity factors from 85 to 89 percent over the 2014-2025 period and 31 to 35 percent at minimum demand.

Exhibit 3-20 Eastern Interconnection fleet weekly capacity factors for remaining generation types in No-Retirements case (2014-2025)



As shown in Exhibit 3-21, the Retirements case predicts that peak week capacity factors for gas-fired generation would see a greater increase than predicted in the No-Retirements case. This is consistent with the findings discussed above on the increased share of overall generation from natural gas-fueled plants as coal-fired units retire. The peak capacity factor for combined cycle generation is projected to increase from 72 percent in 2014 to 84 percent in 2025. Gas-fired generation used as peakers are expected to have increased peak week capacity factors as well, from between 8 and 38 percent in 2014 to between 29 and 68 percent in 2025, depending on the generation type.

Exhibit 3-21 Eastern Interconnection fleet weekly capacity factors for gas-fired generation in Retirements case



Under the Retirements case, capacity factors for most other forms of generation remain much higher than for gas-fired units, despite the 35 percent increase in gas-fired generation capacity factors, as shown in Exhibit 3-21. These other types of generation – nuclear, coal, and hydroelectric – continue to be used more to supply year-round baseload generation than natural gas. The exception is steam petroleum, which is increasingly used as a peaker over the period. The major difference between the two cases is the marked growth in peak week coal-fired capacity factors. In the No-Retirements case, peak week coal capacity factors increase from 85 percent in 2014 to 89 percent by 2025, while in the Retirements case, the increase is more significant, growing from 87 percent in 2014 to 94 percent by 2025 (Exhibit 3-22). Capacity factors for nuclear and hydroelectric remain nearly constant between the two cases.

Exhibit 3-23 shows a comparison of the peak week capacity factor for the Eastern Interconnection's fleet for all generation types for both cases in 2025. The differences in peak week capacity factors becomes clear as it can be seen that only nuclear and hydroelectric capacity are unaffected by changes in the rest of the fleet because they are physically constrained from increasing output.

Exhibit 3-22 Eastern Interconnection fleet weekly capacity factors for remaining generation types in Retirements case (2014-2025)

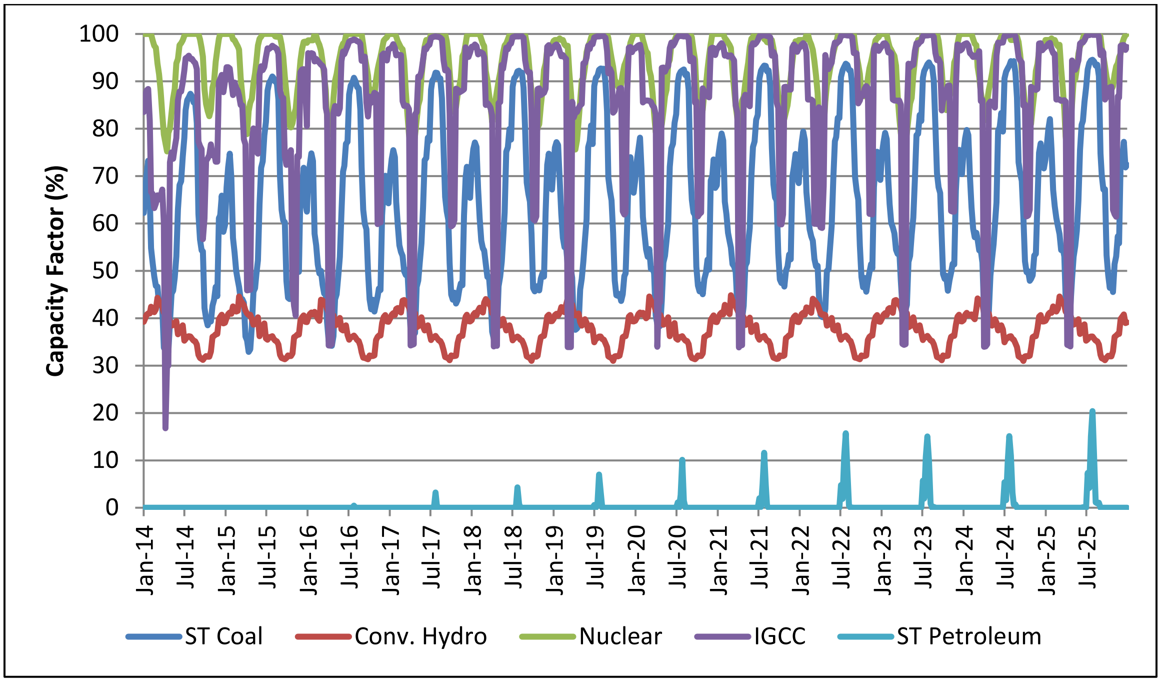
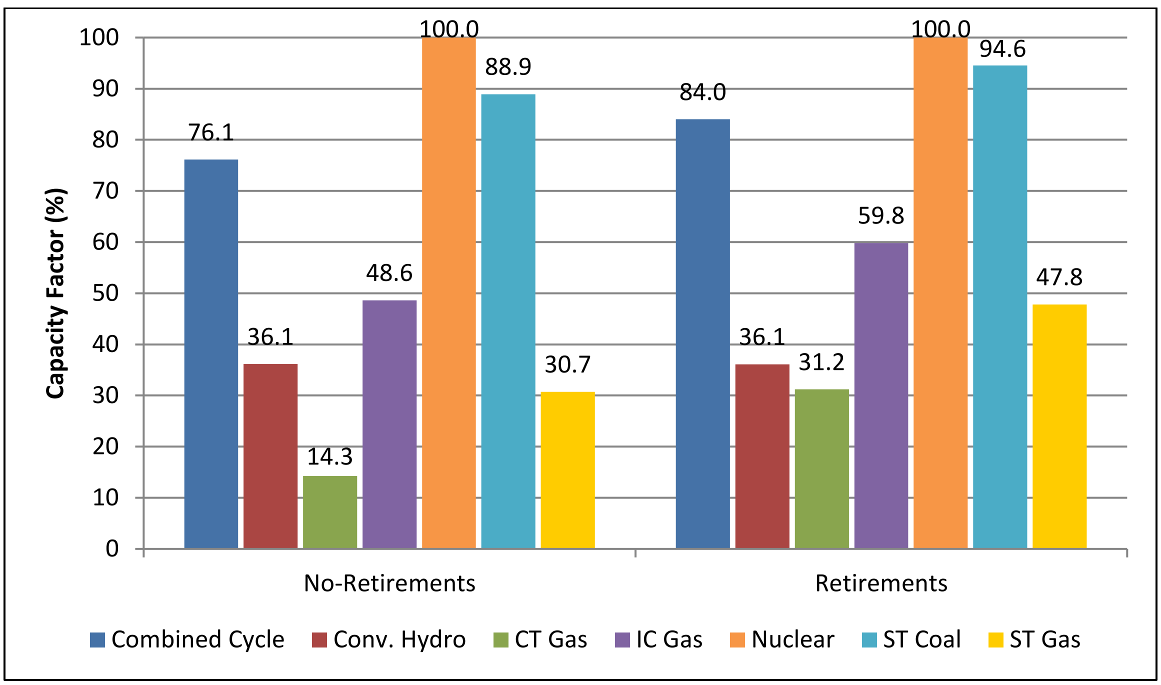


Exhibit 3-23 Eastern Interconnection fleet peak week capacity factors for generation types in both cases for 2025



3.3.3 Fuel Consumption

From 2014-2025, coal and natural gas consumption for power generation increase, as seen in Exhibit 3-24 and Exhibit 3-25. Without retirements, coal consumption would be expected to increase as a greater number of units are dispatched to meet load growth with some operating at low efficiencies. With retirements however, retirement-driven coal consumption differences between the cases are offset by increases in natural gas consumption. Natural gas generators are the most likely source of replacement power for retiring coal-fired units, so the increase in natural gas consumption is due to coal retirements and favorable fuel price economics for natural gas-fired generators. Under the No-Retirements and Retirements cases, coal consumption increases by 17 percent and 7 percent, respectively. Natural gas consumption rises 32 percent under the No-Retirements case and 56 percent under the Retirements case.

Exhibit 3-24 Coal consumption (2014-2025)

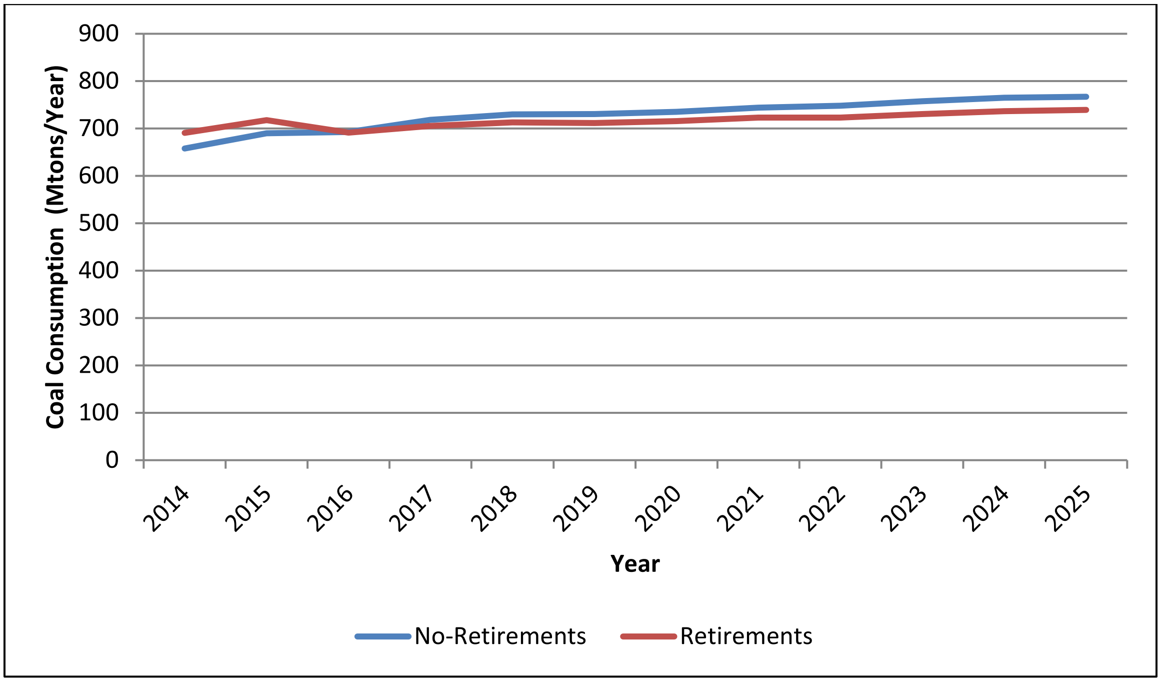


Exhibit 3-25 Natural gas consumption (2014-2025)

3.4 Emissions Profile

The MATS rule targets criteria air-emissions from power plants. It was found that in the Retirements case, where any non-MATS compliant power plants would be retired, criteria air emissions experience a net decrease by between 2 percent (Mercury) and 12 percent (NO_x) over the period. The bulk of this decrease occurs in the short-term as retirements occur, after which emissions remain steady or grow slightly over the remainder of the period.

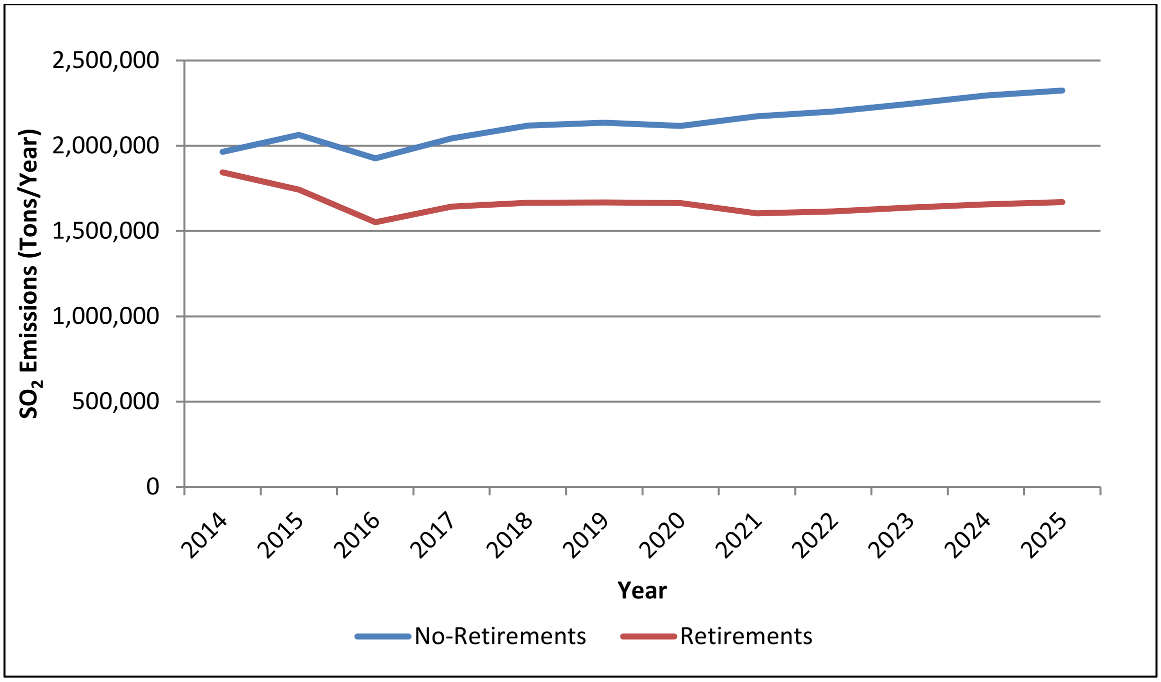
NO_x emissions also decline under the No-Retirements case, by nearly 9 percent over the period. For SO_2 and Mercury under the No-Retirements case, emissions increase by 18 and 12 percent, respectively.

CO_2 emissions, which are not covered under MATS, increase steadily for both cases over the period, with the emissions in the No-Retirements case increasing slightly more: 11 percent versus 9 percent for the Retirements case.

3.4.1 SO_2 Emissions

As shown in Exhibit 3-26, under the No-Retirements case, SO_2 emissions increase by 18 percent, while they decrease 9 percent in the Retirements case since many of the retiring units lack emissions controls. Under the No-Retirements case, SO_2 emissions increase throughout the projection but experience decreases in 2016 and 2020. Emissions for the Retirements case project a sharp decline from 2014-2016 (1,844,158 tons/year to 1,551,733 tons/year) when the majority of retirements occur. Following the sharp decline, increases are projected in 2017 and 2022. Because of coal- and petroleum-fired generation retirements, after 2015, SO_2 emissions in the Retirements case never exceed 1,700,000 tons/year.

Exhibit 3-26 Eastern Interconnection annual SO_2 emissions (2014-2025)



3.4.2 NO_x Emissions

NO_x emissions, while not directly called out under MATS, will decrease by 1 percent under the No-Retirements case and by 12 percent under the Retirements case, as shown in Exhibit 3-27. The decrease is a result of coal-fired unit retirements, installation of control technologies to meet environmental regulations, and increased natural gas utilization. Under the No-Retirements case, NO_x emissions decrease throughout the projection but experience increases in 2015, 2017, and 2021. Similar to what was seen with SO_2 emissions, for the Retirements case, NO_x emissions project a sharp decline from 2014-2016 (49,913 tons/year to 39,820 tons/year) with an increase in 2017 followed by a decline in 2020. Even though NO_x emissions increase from 2020-2025 in the No-Retirements case, over the period of projection, they are actually decreasing by 1 percent.

3.4.3 Mercury Emissions

Mercury emissions in the No-Retirements case increase across the projection by 12 percent, with a decrease seen in 2016. Mercury emissions predict a 1 percent decrease for the Retirements case as a result of coal- and petroleum-fired power plant retirements. As shown in Exhibit 3-28, Mercury emissions never exceed 30,500 lbs/year in the Retirements case after 2015, while the No-Retirements case reaches a maximum of 35,580 lbs/year in 2025.

3.4.4 CO_2 Emissions

In the No-Retirements and Retirements cases, CO_2 emissions decline slightly in 2016, then gradually increase through the remainder of the period. Overall, emissions increase by 10 percent under the No-Retirements case and 8 percent under the Retirements case, as shown in Exhibit 3-29.

Exhibit 3-27 Eastern Interconnection annual NO_x emissions (2014-2025)

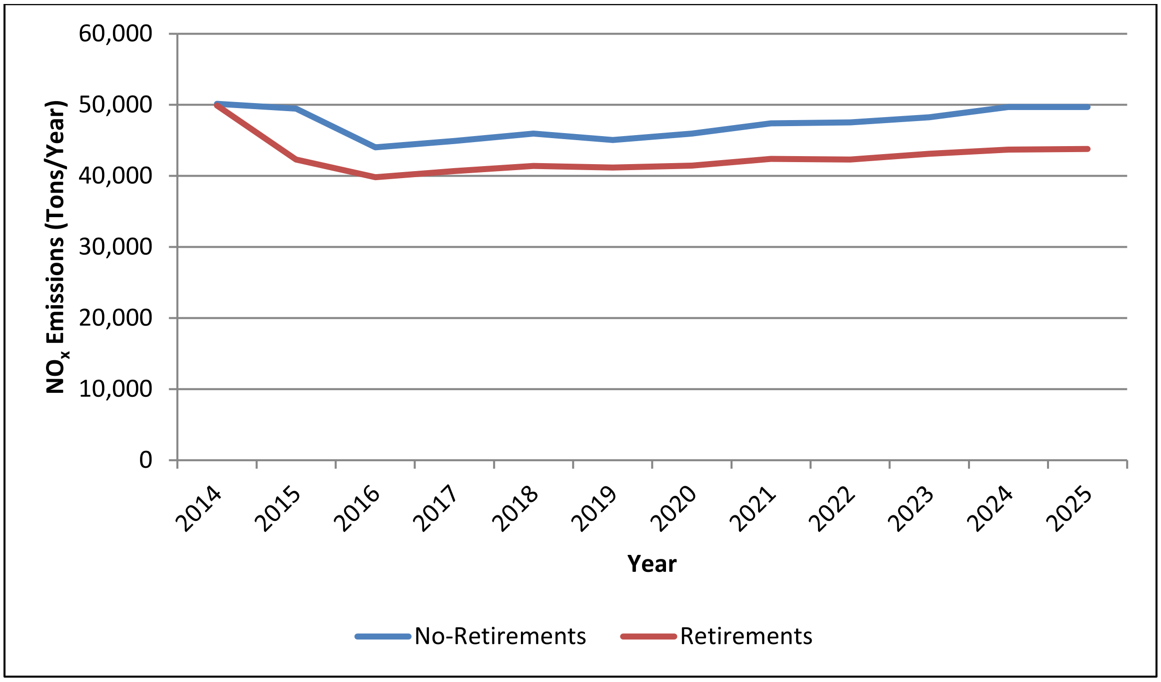


Exhibit 3-28 Eastern Interconnection annual mercury emissions (2014-2025)

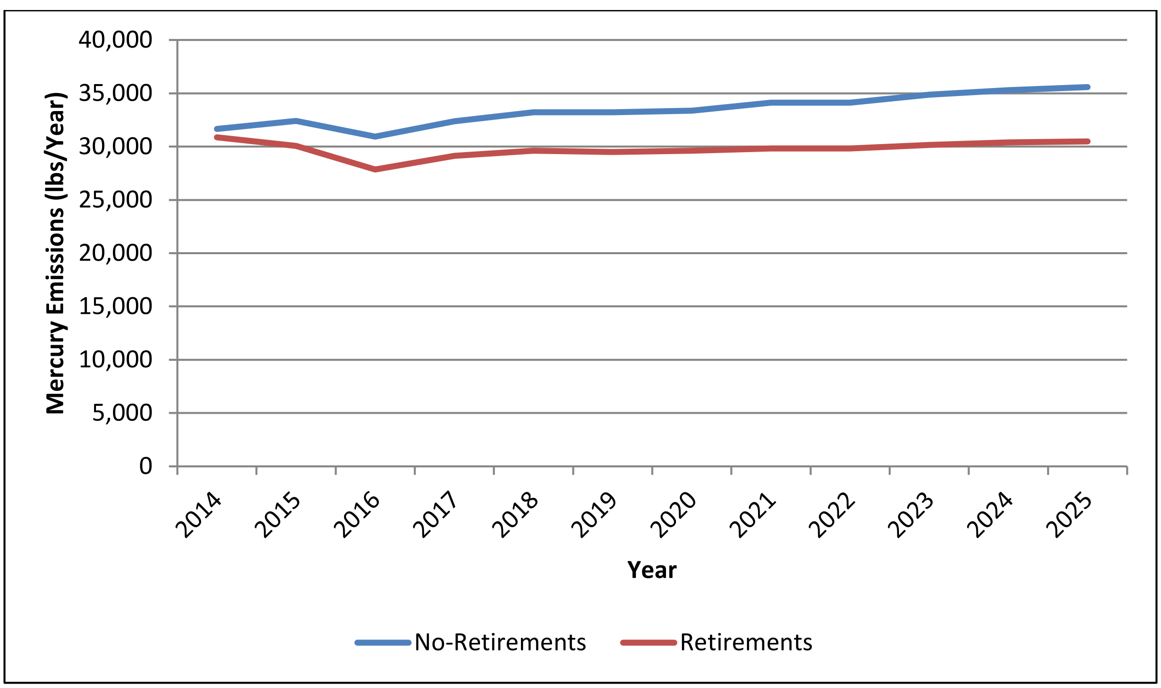
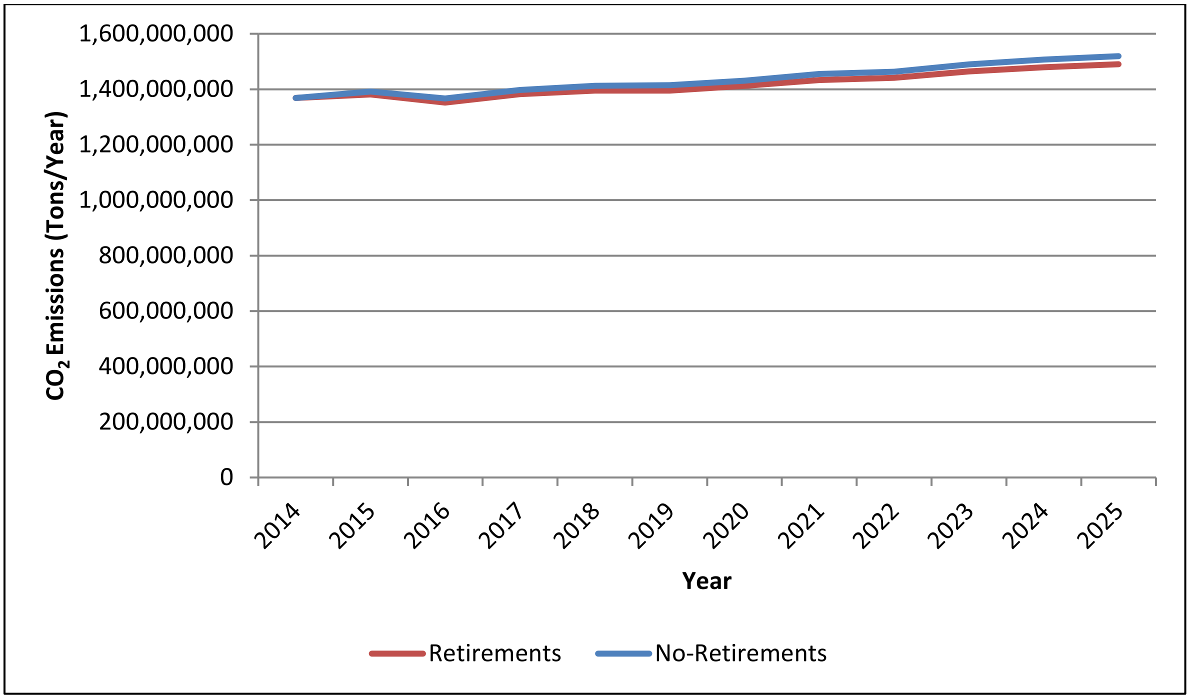


Exhibit 3-29 Eastern Interconnection annual CO_2 emissions (2014-2025)



4 Conclusions

When the U.S. EPA MATS takes effect in 2015, the Eastern Interconnection and the other U.S. interconnections will face many changes in their electric power systems. These changes are in part due to the owners and operators of many marginal and aging coal- and petroleum-fired generators opting to retire the plants rather than expend capital to continue operation.

This report has found that MATS-related retirements result in a net loss of 30.3 GW of coal-fired and 16 GW of petroleum-fired electricity generating capacity over the study period. These retirements are projected to have the desired outcome of reducing air emissions such as SO_2, NO_x, and Mercury in the Eastern Interconnection compared to the case where those units did not retire. However, these retirements are also expected to exacerbate other issues, such as price increases and the need for new generating capacity.

The analysis found that in both cases, the Eastern Interconnection experiences price increases and becomes increasingly reliant on electricity imports. The price impacts are significantly greater in the Retirements case, with the difference in price impacts between the cases being primarily linked to increased prices during periods of peak demand.

This report also found that in the Retirements case, significant capacity additions are required above those units considered certain in queue. Incremental additions are projected to be required as early as 2020 to meet peak demand. In the No-Retirements case, the Eastern Interconnection is not expected to need any additional capacity.

The following sections provide a more detailed summary of the modeling results.

Changes in Generating Capacity Mix

Based on announced unit retirement plans and Certain Capacity additions, between 2014 and 2025, the Eastern Interconnection will see a net loss of 41.9 GW of generating capacity. This consists of a net loss of 30.3 GW of coal-fired generation, 16 GW of petroleum-fired generation, and 3.4 GW of natural gas-fired generation, and a net gain of 4.9 GW of nuclear capacity. The Eastern Interconnection will also see small gains in wind, solar, hydro, and other forms of generation.

Price Impacts

The anticipated loss of generating capacity, combined with a projected 1 percent compound annual increase in demand in the Eastern Interconnection over the period analyzed in this report, shows that for the Retirements case, the average on-peak LMP is projected to increase by 70 percent to $58/MWh, whereas in the No-Retirements case, the increase is only 40 percent, to $47/MWh.

The annual cost of electricity to meet total demand for the Eastern Interconnection is higher in the Retirements case than in the No-Retirements case, increasing from $60 billion in 2014 to approximately $150 billion in 2025, compared to approximately $120 billion in 2025 in the No-Retirements case. The difference in the two cases is primarily the result of increased costs to meet on-peak demands in the Retirements case, which increases by $62.8 billion over the period compared to $36.8 billion in the No-Retirements case.

Reserve Margins and Meeting Peak Demand

The Eastern Interconnection is expected to experience decreasing reserve margins across the period evaluated in this report. In the No-Retirements case, reserves do not fall below the NERC target planning reserve level despite decreasing margins, nor would incremental capacity additions be required in order to meet peak demand.

In the Retirements case however, this report found the Eastern Interconnection would require nearly 16 GW of incremental capacity additions by 2025 in order to satisfy peak demand. Furthermore, over 44 GW of incremental capacity would be required on an annual basis to meet the NERC targeted planning reserve level. These additions are incremental to the capacity needed to meet peak demand, bringing the total capacity additions needed to 60 GW.

To provide context, the combined generation queues in the Eastern Interconnection currently include 111 GW of Certain[40] and Speculative Capacity with in-service dates between 2014 and 2025. (3) However, according to the FERC 2011 RTO/ISO Performance Metrics Report, (4) only 12-15 percent of projects within the queue ultimately result in an operating plant, meaning that the likely generation total is between 13 and 17 GW – less than the incremental capacity needed to meet demand.

Transmission Imports

The results of the model indicate that the Eastern Interconnection would be increasingly reliant on transmission imports from Canada to meet peak demand. In both cases, imports are projected

[40] In this instance, certain generation includes both existing-certain and planned-certain generation.

to increase about 21 percent over the period, with the maximum amount of imports reaching approximately 10 GW. Even though MISO and ISO-NE will receive imports, they will reach their tie line capacity, thus creating a potential for significant reliability issues, particularly for MISO where imports may provide the main method of relieving a 5-7 GW RTO projected capacity shortfall by 2016/2017. (5)

Generation Utilization and Fuel Consumption

Although available capacity differs under the Retirements and No-Retirements cases, generation dispatch remains fairly consistent. Under both cases, coal-fired and nuclear generation continue to service the majority of load in the Eastern Interconnection. In the Retirements case, for example, 72 percent of demand within the Eastern Interconnection would still be served by coal-fired and nuclear generation, with natural gas-fired generation providing only a small portion of the overall mix.

In each case, generation from nuclear increases slightly. Generation from coal experiences overall growth under both cases, although that growth is more modest in the Retirements case. Natural gas generation is the reverse – showing greater increases over the period under the Retirements case.

Capacity factors for natural gas-fired generation increase under both cases, although to a greater extent under the Retirements case. For natural gas-fired combined cycle units, annual capacity factors increase from 24 to 29 percent under the No-Retirements case, and from 25 to 35 percent under the Retirements case. Capacity factors for steam coal units also increase more under the Retirements case, from 57 to 67 percent, compared to the No-Retirements case, which only increases from 54 to 59 percent.

Coal consumption grows slightly under both cases, increasing by 17 percent to reach 767 Mtons of annual consumption under the No-Retirements case, and increasing by 7 percent over the period to reach 739 Mtons for the Retirements case. Natural gas consumption shows a greater increase in both cases: rising by 32 percent under the No-Retirements case and 56 percent under the Retirements case.

Emissions Profile

The MATS rule targets criteria air-emissions from power plants. It was found that in the Retirements case, where any non-MATS compliant power plants would be retired, criteria air emissions experience a net decrease by between 2 percent (Mercury) and 12 percent (NO_x) over the period. The bulk of this decrease occurs in the short-term as retirements occur, after which emissions remain steady or grow slightly over the remainder of the period.

NO_x emissions also decline under the No-Retirements case, by nearly 9 percent over the period. For SO_2 and Mercury under the No-Retirements case, emissions increase by 18 and 12 percent, respectively.

CO_2 emissions, which are not covered under MATS, increase steadily for both cases over the period, with the emissions in the No-Retirements case increasing slightly more: 11 percent versus 9 percent for the Retirements case.

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Appendix A: Retirements Announced/Completed through April 2014

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Celanese:1	13	1/1/2011	Cape Fear:2	39	3/1/2013
Celanese:2	26	1/1/2011	H B Robinson:GT1	15	3/1/2013
Dean H Mitchell:11	110	1/1/2011	Riverbend:4	96	4/1/2013
Dean H Mitchell:4	125	1/1/2011	Riverbend:5	96	4/1/2013
Dean H Mitchell:5	125	1/1/2011	Riverbend:6	136	4/1/2013
Dean H Mitchell:6	125	1/1/2011	Riverbend:7	136	4/1/2013
Fourche CWW:3	0.5	1/1/2011	Danskammer:1	66.5	4/30/2013
Houma:12	3.3	1/1/2011	Danskammer:2	63.7	4/30/2013
R E Burger:4	156	1/1/2011	Danskammer:3	138.5	4/30/2013
R E Burger:5	156	1/1/2011	Danskammer:4	236.7	4/30/2013
Somerset (MA):2	23	1/1/2011	Buck:5	131	5/1/2013
Sutherland:2	29.7	1/1/2011	Buck:6	131	5/1/2013
AES Thames:1	153.03	1/27/2011	MERC:1	18	5/15/2013
Somerset (MA):6	109.06	2/1/2011	Kewaunee 1	574	5/31/2013
Edwardsport:6	40	3/1/2011	Dover (Kent):1	50	6/1/2013
Edwardsport:7	45	3/1/2011	Dover (Kent):ST1	16	6/1/2013
Edwardsport:8	75	3/1/2011	Lansing:3	29.5	6/1/2013
Harvey Couch:1	12	3/1/2011	Norwalk Harbor:1	164	6/1/2013
AES Westover:8	82	3/19/2011	Norwalk Harbor:10	17.125	6/1/2013
CID Gas Rec:1	3.3	4/1/2011	Norwalk Harbor:2	172	6/1/2013
Peru IL:10	2	4/1/2011	Ridgeview:9	0.8	6/1/2013
Peru IL:3	1.8	4/1/2011	Ritchie:GT1	16	6/1/2013
Peru IL:3A	1.8	4/1/2011	Shelby Munic Lgt Plt:1	12	6/1/2013
Buck:3	76	5/1/2011	Shelby Munic Lgt Plt:2	12	6/1/2013
Buck:4	39	5/1/2011	Shelby Munic Lgt Plt:4	7	6/1/2013
Hopkinton:2	1.7	5/1/2011	Blount St:6	50.8	6/30/2013
Indian River DE:1	91	5/2/2011	Blount St:7	50.1	6/30/2013
Eddystone:1	288	5/31/2011	MMSD:1	15	7/1/2013
Brunot Island:1B	20	6/1/2011	Widows Creek:3	113	7/1/2013
Brunot Island:1C	20	6/1/2011	Widows Creek:5	113	7/1/2013
CapitolHeat:31	1	6/1/2011	Widows Creek:6	113	7/1/2013
CapitolHeat:32	1	6/1/2011	Widows Creek:1	113	8/1/2013

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Cromby:1	147	6/1/2011	Widows Creek:2	113	8/1/2013
Greenville Steam:1	19	6/1/2011	Chamois:1	17	9/1/2013
Natchez:1	73	6/1/2011	Chamois:2	50	9/1/2013
Rex Brown:1	15	6/1/2011	Harllee Branch:2	325	9/1/2013
Riviera:3	280	6/1/2011	Park 500:TG2	5.5	9/1/2013
Riviera:4	291	6/1/2011	Titus:1	83	9/1/2013
Moorhead:6	7.9	7/1/2011	Titus:2	83	9/1/2013
Nine Mile:1	50	9/1/2011	Titus:3	83	9/1/2013
Nine Mile:2	107	9/1/2011	Ridgewood Prov:1	0.874	9/2/2013
Ravenswood:G34	40.3	9/1/2011	Ridgewood Prov:2	0.874	9/2/2013
Venice:GT1	30	9/1/2011	Ridgewood Prov:3	0.874	9/2/2013
Viaduct CT:1	34	9/1/2011	Ridgewood Prov:4	0.874	9/2/2013
R E Burger:3	94	9/2/2011	Ridgewood Prov:5	0.874	9/2/2013
Jack McDonough:2	251	9/30/2011	Ridgewood Prov:6	0.874	9/2/2013
Monroe (LA):10	23	10/1/2011	Ridgewood Prov:7	0.874	9/2/2013
Monroe (LA):11	41	10/1/2011	Ridgewood Prov:8	0.874	9/2/2013
Monroe (LA):12	74	10/1/2011	Ridgewood Prov:9	0.874	9/2/2013
Wood River:1	39.67	10/1/2011	Mitchell-PA:2	82	10/8/2013
Wood River:2	39.67	10/1/2011	Mitchell-PA:3	288	10/8/2013
Wood River:3	39.67	10/1/2011	Hatfields Ferry:1	570	10/9/2013
W H Weatherspoon:ST1	49	10/2/2011	Hatfields Ferry:2	570	10/9/2013
W H Weatherspoon:ST2	49	10/2/2011	Hatfields Ferry:3	570	10/9/2013
W H Weatherspoon:ST3	79	10/2/2011	Dean H Mitchell:9	17	10/31/2013
Barrett:G7	20.2	10/14/2011	L V Sutton:ST1	98	11/1/2013
Bridgewater (NC)	23	11/1/2011	L V Sutton:ST2	107	11/1/2013
Timberline Trail LGE:6	0.8	11/1/2011	L V Sutton:ST3	411	11/1/2013
Timberline Trail LGE:7	0.8	11/1/2011	Canadys Steam:2	115	11/15/2013
Geneva IL:6	1.6	11/30/2011	Canadys Steam:3	180	11/15/2013
Blount St:3	39.4	12/1/2011	Fair:1	24	11/30/2013
Blount St:4	21.2	12/1/2011	Fair:2	42	11/30/2013
Blount St:5	26.6	12/1/2011	Blue Valley:1	21	12/31/2013
Chesapeake:G10	23	12/1/2011	Blue Valley:2	21	12/31/2013
Chesapeake:G7	25	12/1/2011	Blue Valley:3	51	12/31/2013

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Chesapeake:G8	26	12/1/2011	Coldwater MI:4	2.5	12/31/2013
Chesapeake:G9	25	12/1/2011	Coldwater MI:5	6	12/31/2013
Hudson:1	355	12/1/2011	Baldwin City:5	1	1/1/2014
Kitty Hawk GT:1	23	12/1/2011	Baldwin City:6	1	1/1/2014
Kitty Hawk GT:2	22	12/1/2011	Coit GT:2	19	1/1/2014
Meredosia:3	215	12/1/2011	Edge Moor:3	86	1/1/2014
Meredosia:4	156	12/1/2011	Freeport 1:4	4.5	1/1/2014
Middlepoint TN:1	1.4	12/1/2011	Gadsden:1	64	1/1/2014
Middlepoint TN:2	2.8	12/1/2011	Gadsden:2	66	1/1/2014
Peru IL:IC1	6	12/1/2011	Hamilton(OH):5	10	1/1/2014
Teche:2	33	12/1/2011	Hamilton(OH):GT1	10	1/1/2014
Vermillion PS:1	63	12/1/2011	Independence IA:6	2.8	1/1/2014
Vermillion PS:2	99	12/1/2011	Indian River DE:3	170	1/1/2014
Vermillion PS:3	12	12/1/2011	Jefferies:1	44	1/1/2014
Conners Crk NG:15	100	12/31/2011	Jefferies:2	44	1/1/2014
Conners Crk NG:16	130	12/31/2011	Lansing:2	11.2	1/1/2014
Hutsonville:3	76	12/31/2011	Lone Star:1	50	1/1/2014
Hutsonville:4	78	12/31/2011	Mad River GT:1	30	1/1/2014
Marysville:7	83	12/31/2011	Mad River GT:2	30	1/1/2014
Marysville:8	83	12/31/2011	Montville:5	81.59	1/1/2014
Cliffside:1	39	1/1/2012	Moore County:1	46	1/1/2014
Cliffside:2	39	1/1/2012	Murray Gill EC:2	56	1/1/2014
Cliffside:3	62	1/1/2012	NE City 1:5	1.6	1/1/2014
Cliffside:4	62	1/1/2012	Neosho:3	67	1/1/2014
Countryside Genco LL:1	1.3	1/1/2012	Nine Springs:1	15.8	1/1/2014
Countryside Genco LL:2	1.3	1/1/2012	Northeast IN:2	12	1/1/2014
Countryside Genco LL:3	1.3	1/1/2012	Painesville:2	7	1/1/2014
Countryside Genco LL:4	1.3	1/1/2012	Peru IN:3	12	1/1/2014
Countryside Genco LL:5	1.3	1/1/2012	Pulliam:5	51.6	1/1/2014
Countryside Genco LL:6	7.8	1/1/2012	Rantoul IL:5	0.8	1/1/2014
Cromby:2	211	1/1/2012	Rantoul IL:8	3	1/1/2014
Salem Harbor:1	81.42	1/1/2012	Riverside MEC:3HS	4.8	1/1/2014

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Salem Harbor:2	78.76	1/1/2012	Rock River:1NG	75	1/1/2014
Tecumseh:1	18	2/1/2012	S O Purdom:2	10	1/1/2014
Tecumseh:2	19	2/1/2012	Southhold:1	14	1/1/2014
Tulsa:3	65	2/1/2012	Southwestern:2	78	1/1/2014
Williston:2	5.2	2/1/2012	Story City:4	1.3	1/1/2014
R Gallagher:1	140	2/2/2012	Suwannee Riv:ST2	30	1/1/2014
R Gallagher:3	140	2/2/2012	Ty Cooke:GT1	12.5	1/1/2014
Phil Sporn:5	450	2/13/2012	West Substation:1	19	1/1/2014
Binghamton:1	49.4	2/17/2012	Widows Creek:4	113	1/1/2014
BeeBee:13	18.2	2/18/2012	Yazoo:3	13	1/1/2014
Jack McDonough:1	251	2/28/2012	Walter C Beckjord:4	150	4/16/2014
Mitchell:4C	39.7	3/1/2012	B L England:1	113	5/1/2014
State Line IN:3	197	3/26/2012	DeepwaterNJ:1	78.6	5/31/2014
State Line IN:4	318	3/26/2012	DeepwaterNJ:6	80	5/31/2014
USDOE SRS D-Area:1	12.5	4/1/2012	Salem Harbor:3	149.9	5/31/2014
USDOE SRS D-Area:2	12.5	4/1/2012	Salem Harbor:4	437.4	5/31/2014
USDOE SRS D-Area:3	12.5	4/1/2012	Burlington Gen:91	46	6/1/2014
USDOE SRS D-Area:3B	9.4	4/1/2012	Doswell:7	187	6/1/2014
USDOE SRS D-Area:4	12.5	4/1/2012	Portland:1	158	6/1/2014
Viking Energy:1	16	4/1/2012	Portland:2	243	6/1/2014
Walter C Beckjord:1	94	4/2/2012	Riverside BG&E:6	115	6/1/2014
Conroe:1	1	4/11/2012	Vermont Yankee 1	628	10/1/2014
Conroe:2	1	4/11/2012	Welsh:2	528	12/1/2014
Conroe:3	1	4/11/2012	Asheville:ST2	187	12/31/2014
Dan River:1	69	4/30/2012	Chesapeake:ST1	111	12/31/2014
Dan River:2	69	4/30/2012	Chesapeake:ST2	111	12/31/2014
Dan River:3	145	4/30/2012	Chesapeake:ST3	162	12/31/2014
Hudson Ave:4	17.4	5/1/2012	Chesapeake:ST4	221	12/31/2014
Hudson Ave:GT3	19	5/1/2012	North Branch:1	77	12/31/2014
Hudson Ave:GT5	17.9	5/1/2012	Wabash River:2	85	12/31/2014
Moselle:1	59	5/1/2012	Wabash River:3	85	12/31/2014
Eddystone:2	311	5/31/2012	Wabash River:4	85	12/31/2014
Alma:1	20.6	6/1/2012	Wabash River:5	95	12/31/2014
Alma:2	19.7	6/1/2012	Yorktown:1	162	12/31/2014
Alma:3	20.6	6/1/2012	Yorktown:2	165	12/31/2014
Buzzard Point:E1	16	6/1/2012	B C Cobb:4	160	1/1/2015
Buzzard Point:E2	16	6/1/2012	B C Cobb:5	160	1/1/2015

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Buzzard Point:E4	16	6/1/2012	Bay Shore:1	136	1/1/2015
Buzzard Point:E5	16	6/1/2012	Carthage:10	6	1/1/2015
Buzzard Point:E6	16	6/1/2012	Crete Muni Power:6	3.3	1/1/2015
Buzzard Point:E7	16	6/1/2012	Cushing OK:9	2.7	1/1/2015
Buzzard Point:E8	16	6/1/2012	Dale:1	23	1/1/2015
Buzzard Point:W10	16	6/1/2012	Dale:2	23	1/1/2015
Buzzard Point:W11	16	6/1/2012	Dale:3	75	1/1/2015
Buzzard Point:W12	16	6/1/2012	Dale:4	75	1/1/2015
Buzzard Point:W13	16	6/1/2012	Dicks Creek:1	110	1/1/2015
Buzzard Point:W14	16	6/1/2012	Dunkirk:1	75	1/1/2015
Buzzard Point:W15	16	6/1/2012	Dunkirk:2	75	1/1/2015
Buzzard Point:W16	16	6/1/2012	East River:7	186.6	1/1/2015
Buzzard Point:W9	16	6/1/2012	Falls City NE:3	2.3	1/1/2015
Green Island Hydroelectric Project	6	6/1/2012	Forest City IA:2	2.2	1/1/2015
Niles:ST2	108	6/1/2012	G W Ivey IC:11	3	1/1/2015
Pearl Station:ST1	22.2	6/1/2012	G W Ivey IC:12	3	1/1/2015
Elrama:1	93	6/2/2012	Gorge (Colchester):1	12.55	1/1/2015
Elrama:2	93	6/2/2012	J R Whiting:1	99.1	1/1/2015
Elrama:3	103	6/2/2012	J R Whiting:2	102	1/1/2015
Kearny:10	122	6/2/2012	J R Whiting:3	124	1/1/2015
Kearny:11	128	6/2/2012	Junction:5	2.5	1/1/2015
Far Rockaway:4	106.5	6/30/2012	Junction:6	1.9	1/1/2015
Glenwood:ST4	116	6/30/2012	Kennett MO:9	6.2	1/1/2015
Glenwood:ST5	113.2	6/30/2012	Miami Fort:ST6	163	1/1/2015
Benning:15	275	7/18/2012	Plant X:3	93	1/1/2015
Benning:16	275	7/18/2012	Princeton IC:3	3.4	1/1/2015
Crawford:ST7	216	8/30/2012	Princeton IC:4	3.4	1/1/2015
Crawford:ST8	326	8/30/2012	Richland:1	14	1/1/2015
Fisk:19	326	8/31/2012	Rock River:2NG	76.7	1/1/2015
AES Greenidge:4	106.3	9/1/2012	Stock Island:IC1	2	1/1/2015
Coldwater MI:3	3.5	9/1/2012	Stock Island:IC2	2	1/1/2015
Kensico	3	9/1/2012	Stock Island:IC3	2	1/1/2015
PPL Veazie Hydro Station	8.1	9/1/2012	Sunbury:5B	23.6	1/1/2015
Riverview:1	25	9/1/2012	Taconite Harbor EC:3	76	1/1/2015
W S Lee:ST3	170	9/1/2012	Waukegan:7	328	1/1/2015

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Albright:1	76	9/2/2012	Waukegan:8	361	1/1/2015
Albright:2	76	9/2/2012	Asbury:2	18	2/1/2015
Albright:3	140	9/2/2012	Harbor Beach:1	103	4/1/2015
Armstrong:1	180	9/2/2012	Harllee Branch:1	266	4/1/2015
Armstrong:2	176	9/2/2012	Harllee Branch:3	509	4/1/2015
Bay Shore:2	138	9/2/2012	Harllee Branch:4	507	4/1/2015
Bay Shore:3	142	9/2/2012	McManus:1	43	4/1/2015
Bay Shore:4	215	9/2/2012	McManus:2	79	4/1/2015
R Paul Smith:3	28	9/2/2012	Scholz:1	46	4/1/2015
R Paul Smith:4	88	9/2/2012	Scholz:2	46	4/1/2015
Rivesville:5	48	9/2/2012	W S Lee:ST1	100	4/1/2015
Rivesville:6	94	9/2/2012	W S Lee:ST2	102	4/1/2015
Willow Island:1	55	9/2/2012	Walter C Beckjord:5	238	4/1/2015
Willow Island:2	186	9/2/2012	Walter C Beckjord:6	420	4/1/2015
Buzzard R GT:10	16	9/15/2012	Yates:1	97	4/1/2015
Buzzard R GT:11	16	9/15/2012	Yates:2	103	4/1/2015
Buzzard R GT:12	16	9/15/2012	Yates:3	111	4/1/2015
Buzzard R GT:13	16	9/15/2012	Yates:4	133	4/1/2015
Buzzard R GT:14	16	9/15/2012	Yates:5	135	4/1/2015
Buzzard R GT:15	16	9/15/2012	Walter C Beckjord:2	94	4/2/2015
Buzzard R GT:6	20	9/15/2012	Walter C Beckjord:3	128	4/2/2015
Buzzard R GT:7	20	9/15/2012	Avon Lake:9	640	4/16/2015
Buzzard R GT:8	20	9/15/2012	New Castle:3	98	4/16/2015
Buzzard R GT:9	20	9/15/2012	New Castle:4	98	4/16/2015
Eastlake:4	240	9/30/2012	New Castle:5	137	4/16/2015
Eastlake:5	597	9/30/2012	Shawville:1	128	4/16/2015
Howard Down:10	23	9/30/2012	Shawville:2	130	4/16/2015
Buck:7	30	10/1/2012	Shawville:3	180	4/16/2015
Buck:8	30	10/1/2012	Shawville:4	180	4/16/2015
Buck:9	15	10/1/2012	Titus:4	19	4/16/2015
Cape Fear:5	148	10/1/2012	Titus:5	20	4/16/2015
Cape Fear:6	175	10/1/2012	Burlington Gen:92	46	5/1/2015
Cheoah	115	10/1/2012	Burlington Gen:93	46	5/1/2015
Hansel:1	50	10/1/2012	Burlington Gen:94	46	5/1/2015
John Sevier:1	178	10/1/2012	Gilbert:1	31	5/1/2015
John Sevier:2	178	10/1/2012	Gilbert:2	25	5/1/2015
Lee:GT1	15	10/1/2012	Gilbert:3	25	5/1/2015
Lee:GT2	27	10/1/2012	Glen Gardner:1	26	5/1/2015

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Lee:GT3	27	10/1/2012	Glen Gardner:2	26	5/1/2015
Lee:GT4	27	10/1/2012	Glen Gardner:3	26	5/1/2015
Morehead Cty GT:1	15	10/1/2012	Glen Gardner:4	26	5/1/2015
Moselle:2	59	10/1/2012	Glen Gardner:5	26	5/1/2015
Niles:ST1	108	10/1/2012	Glen Gardner:6	26	5/1/2015
Riverbend:10	30	10/1/2012	Glen Gardner:7	26	5/1/2015
Riverbend:11	30	10/1/2012	Glen Gardner:8	26	5/1/2015
Riverbend:8	20	10/1/2012	Werner C:1	73	5/1/2015
Riverbend:9	30	10/1/2012	Werner C:2	73	5/1/2015
Elrama:4	175	10/2/2012	Werner C:3	73	5/1/2015
H B Robinson:1	179	10/2/2012	Werner C:4	73	5/1/2015
Potomac River:1	88	10/2/2012	Kearny:9	21	5/2/2015
Potomac River:2	88	10/2/2012	Cedar:1	52	5/31/2015
Potomac River:3	102	10/2/2012	Cedar:2	26	5/31/2015
Potomac River:4	102	10/2/2012	Essex:121	46	5/31/2015
Potomac River:5	102	10/2/2012	Essex:122	46	5/31/2015
Dan River:4	31	10/31/2012	Essex:123	45.6	5/31/2015
Dan River:5	31	10/31/2012	Essex:124	46	5/31/2015
Dan River:6	31	10/31/2012	Middle:1	23	5/31/2015
Cutler:5	69	11/1/2012	Middle:2	23	5/31/2015
Cutler:6	138	11/1/2012	Middle:3	44	5/31/2015
Sanford (FL):ST3	140	11/1/2012	Missouri Ave:B	24	5/31/2015
Whitewater Vlly:1	34.7	11/1/2012	Missouri Ave:C	24	5/31/2015
Great Works Hydro	7.7	11/30/2012	Missouri Ave:D	24	5/31/2015
Port Evergltds:ST1	214	11/30/2012	Ashtabula:5	244	6/1/2015
Port Evergltds:ST2	214	11/30/2012	Astoria GT:10	22.8	6/1/2015
Enid GT:1	11.1	12/1/2012	Astoria GT:11	26.5	6/1/2015
Enid GT:2	10.5	12/1/2012	Astoria GT:12	24.2	6/1/2015
Enid GT:3	11.5	12/1/2012	Astoria GT:13	24.8	6/1/2015
Enid GT:4	10.5	12/1/2012	Astoria GT:5	14.9	6/1/2015
Jefferies:3	152	12/1/2012	Astoria GT:7	14	6/1/2015
Jefferies:4	155	12/1/2012	Astoria GT:8	15.7	6/1/2015
Montgomery:1	25	12/1/2012	Bergen:3	21	6/1/2015
Schuylkill:1	175	12/1/2012	Big Sandy:1	260	6/1/2015
Woodward GT:1	9.5	12/1/2012	Big Sandy:2	800	6/1/2015
Avon Lake:7	96	12/31/2012	Burlington Gen:111	46	6/1/2015
Bay Front:6	23	12/31/2012	Burlington Gen:112	46	6/1/2015
Belle River:ST1	642	12/31/2012	Burlington Gen:113	46	6/1/2015

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Belle River:ST2	642	12/31/2012	Burlington Gen:114	46	6/1/2015
Bremo Bluff:3	74	12/31/2012	Burlington Gen:8	21	6/1/2015
Bremo Bluff:4	161	12/31/2012	Clinch River:3	235	6/1/2015
Bridgeport Harbor:3	368.98	12/31/2012	Eastlake:1	132	6/1/2015
Canadys Steam:1	105	12/31/2012	Eastlake:2	132	6/1/2015
Conesville:3	165	12/31/2012	Eastlake:3	132	6/1/2015
Delta:1	93	12/31/2012	Edison:11	42	6/1/2015
Delta:2	89	12/31/2012	Edison:12	42	6/1/2015
Dolphus Grainger:1	85	12/31/2012	Edison:13	42	6/1/2015
Dolphus Grainger:2	85	12/31/2012	Edison:14	42	6/1/2015
Eaton:1	24.5	12/31/2012	Edison:21	42	6/1/2015
Eaton:2	24.5	12/31/2012	Edison:22	42	6/1/2015
Eaton:3	24.6	12/31/2012	Edison:23	42	6/1/2015
Anadarko:1	12	1/1/2013	Edison:24	42	6/1/2015
Anadarko:2	12	1/1/2013	Edison:31	42	6/1/2015
Ascutney GT:1	13.35	1/1/2013	Edison:32	42	6/1/2015
Auburn NE:2	1	1/1/2013	Edison:33	42	6/1/2015
Austin Downtown:5	5.4	1/1/2013	Edison:34	42	6/1/2015
B C Cobb:1	59	1/1/2013	Essex:101	42	6/1/2015
B C Cobb:2	68	1/1/2013	Essex:102	42	6/1/2015
B C Cobb:3	68	1/1/2013	Essex:103	42	6/1/2015
Baldwin City:3	1	1/1/2013	Essex:104	42	6/1/2015
Big Cajun 1:1	110	1/1/2013	Essex:111	46	6/1/2015
Big Cajun 1:2	110	1/1/2013	Essex:112	46	6/1/2015
Blelleville KS:4	1	1/1/2013	Essex:113	46	6/1/2015
Blelleville KS:5	1.7	1/1/2013	Essex:114	46	6/1/2015
Boise Cascade:1	4	1/1/2013	Glen Lyn:5	95	6/1/2015
Boise Cascade:2	4	1/1/2013	Glen Lyn:6	240	6/1/2015
Boise Cascade:3	7.5	1/1/2013	Kammer:1	210	6/1/2015
Bryan GT:6	6	1/1/2013	Kammer:2	210	6/1/2015
Burton GT:1	10	1/1/2013	Kammer:3	210	6/1/2015
Burton GT:2	10	1/1/2013	Kanawha River:1	200	6/1/2015
Burton GT:3	10	1/1/2013	Kanawha River:2	200	6/1/2015
CABOT:9	5.7	1/1/2013	Lake Shore ST:18	245	6/1/2015
Carrollton:3	1.8	1/1/2013	Mercer:3	115	6/1/2015
Carrollton:7	2.5	1/1/2013	Muskingum River:1	205	6/1/2015
Carthage:6	2	1/1/2013	Muskingum River:2	205	6/1/2015
Carthage:7	2.2	1/1/2013	Muskingum River:3	215	6/1/2015

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Carthage:8	2.5	1/1/2013	Muskingum River:4	215	6/1/2015
Carthage:9	4	1/1/2013	Muskingum River:5	585	6/1/2015
Charles P Keller:10	3.2	1/1/2013	National Park:1	21	6/1/2015
Charles P Keller:11	5.2	1/1/2013	O H Hutchings:1	59	6/1/2015
Charles P Keller:7	2	1/1/2013	O H Hutchings:2	56	6/1/2015
Charles P Keller:8	2.5	1/1/2013	O H Hutchings:3	64	6/1/2015
Charles P Keller:9	3.2	1/1/2013	O H Hutchings:5	64	6/1/2015
Cherry Street:10	2.1	1/1/2013	O H Hutchings:6	64	6/1/2015
Cherry Street:11	2.1	1/1/2013	Phil Sporn:1	150	6/1/2015
Cherry Street:7	2.8	1/1/2013	Phil Sporn:2	150	6/1/2015
Cherry Street:8	3.4	1/1/2013	Phil Sporn:3	150	6/1/2015
Clay Center:1	0.9	1/1/2013	Phil Sporn:4	150	6/1/2015
Clay Center:ST5	3	1/1/2013	Picway:5	100	6/1/2015
Columbia W&L Dept.:GT6	12.5	1/1/2013	Sewaren:1	104	6/1/2015
Columbus Street:4	9.5	1/1/2013	Sewaren:2	118	6/1/2015
Comanche (OK):IC1	4	1/1/2013	Sewaren:3	107	6/1/2015
Crete Muni Power:1	0.4	1/1/2013	Sewaren:4	124	6/1/2015
Crete Muni Power:2	1.3	1/1/2013	Sewaren:6	105	6/1/2015
Crete Muni Power:3	0.9	1/1/2013	Sunbury:1	80	6/1/2015
Crete Muni Power:4	1.1	1/1/2013	Sunbury:2	80	6/1/2015
Crete Muni Power:5	2.5	1/1/2013	Sunbury:3	94	6/1/2015
Cumberland (WI):1	0.65	1/1/2013	Sunbury:4	134	6/1/2015
Cumberland (WI):2	0.22	1/1/2013	Tanners Creek:1	145	6/1/2015
Cumberland (WI):3	0.2	1/1/2013	Tanners Creek:2	145	6/1/2015
Cumberland (WI):4	1.24	1/1/2013	Tanners Creek:3	205	6/1/2015
Cushing OK:1	1.8	1/1/2013	Tanners Creek:4	500	6/1/2015
Cushing OK:2	0.8	1/1/2013	Eastlake:6	29	6/2/2015
Cushing OK:3	0.4	1/1/2013	O H Hutchings:4	64	6/2/2015
Cushing OK:4	0.4	1/1/2013	Astoria:ST2	184.6	7/30/2015
Cushing OK:5	0.4	1/1/2013	Johnsonville:S10	144	12/1/2015
Cushing OK:6	0.6	1/1/2013	Austin Northeast:1	29.3	12/31/2015
Cushing OK:7	1.9	1/1/2013	Black Dog:3	79	12/31/2015
Cushing OK:8	1.9	1/1/2013	Black Dog:4	162	12/31/2015
Diesel Plant:2	2.3	1/1/2013	Eagle Valley:2	39	12/31/2015
Diesel Plant:5	3.2	1/1/2013	Eagle Valley:3	40	12/31/2015
Diesel Plant:6	2.8	1/1/2013	Eagle Valley:4	57	12/31/2015
Diesel Plant:7	5.1	1/1/2013	Eagle Valley:5	63	12/31/2015

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Dubuque:2	13.2	1/1/2013	Eagle Valley:6	100	12/31/2015
Easton 1:7	2	1/1/2013	Edgewater:3	71.5	12/31/2015
Easton 1:8	2	1/1/2013	Frank E Ratts:1	123	12/31/2015
Easton 1:9	2.5	1/1/2013	Frank E Ratts:2	122	12/31/2015
Edge Moor:10	15	1/1/2013	Johnsonville:ST5	113	12/31/2015
Fairbury:1	4	1/1/2013	Johnsonville:ST6	113	12/31/2015
Fairbury:2	2.5	1/1/2013	Johnsonville:ST7	144	12/31/2015
Fairmont:4	5	1/1/2013	Johnsonville:ST8	144	12/31/2015
Falls City NE:1	0.6	1/1/2013	Johnsonville:ST9	144	12/31/2015
Falls City NE:2	0.9	1/1/2013	Meramec:1	125	12/31/2015
Falls City NE:4	0.8	1/1/2013	Meramec:2	127	12/31/2015
Falls City NE:5	1.4	1/1/2013	Meramec:3	266	12/31/2015
Falls City NE:6	2	1/1/2013	Meramec:4	360	12/31/2015
Forest City IA:1	1.3	1/1/2013	Nelson Dewey:1	115.8	12/31/2015
Forest City IA:4	6.1	1/1/2013	Nelson Dewey:2	114.3	12/31/2015
Forest City IA:5	0.7	1/1/2013	Silver Lake RPU:1	9.6	12/31/2015
Freeport 1:1	1.5	1/1/2013	Silver Lake RPU:2	14.3	12/31/2015
Freeport 1:2	2.2	1/1/2013	Silver Lake RPU:3	23.5	12/31/2015
Freeport 1:3	2.1	1/1/2013	Silver Lake RPU:4	56.6	12/31/2015
G W Ivey IC:10	2	1/1/2013	Atlantic 2:1	4.4	1/1/2016
G W Ivey IC:8	2	1/1/2013	Blelleville KS:6	3.7	1/1/2016
G W Ivey IC:9	2	1/1/2013	Cane Run:4	155	1/1/2016
Genesco IL:4	1.3	1/1/2013	Cane Run:5	168	1/1/2016
Genesco IL:7	2.4	1/1/2013	Cane Run:6	240	1/1/2016
Glencoe:5	1	1/1/2013	Carrollton:8	3.7	1/1/2016
Glencoe:6	1	1/1/2013	Chesapeake:G1	20	1/1/2016
Grundy Cntr:1	2.2	1/1/2013	Chesapeake:G2	17	1/1/2016
Havana:1	45.6	1/1/2013	Chesapeake:G4	16	1/1/2016
Havana:2	45.6	1/1/2013	Chesapeake:G6	16	1/1/2016
Havana:3	45.6	1/1/2013	Cii Carbon LLC:G2	23	1/1/2016
Havana:4	45.6	1/1/2013	Cii Carbon LLC:G3	23	1/1/2016
Havana:5	45.6	1/1/2013	Clay Center:2	2	1/1/2016
Henderson:2	13.8	1/1/2013	Columbus Street:5	22	1/1/2016
Hillsdale MI:2	1.9	1/1/2013	Cumberland (WI):5	2.05	1/1/2016
Hillsdale MI:3	2.4	1/1/2013	Devon:10	19.2	1/1/2016
Hillsdale MI:4	3.7	1/1/2013	Dubuque:3	32.1	1/1/2016
Hoisington:1	0.2	1/1/2013	Dubuque:4	36.8	1/1/2016
Hoisington:6	2	1/1/2013	Easton 1:10	3.5	1/1/2016

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Huron:1	14.5	1/1/2013	Fermi:GT1	19	1/1/2016
Hutchinson EC:ST1	17	1/1/2013	Fermi:GT2	19	1/1/2016
Hutchinson EC:ST2	16	1/1/2013	Fermi:GT3	19	1/1/2016
Hutchinson EC:ST3	28	1/1/2013	Fermi:GT4	18	1/1/2016
Independence IA:1	0.8	1/1/2013	Fulton:1	4.5	1/1/2016
Independence IA:5	2.3	1/1/2013	Fulton:2	4.5	1/1/2016
Indianola:1	0.6	1/1/2013	Gaylord GT:1	14.6	1/1/2016
Indianola:2	1.25	1/1/2013	Gaylord GT:2	13.6	1/1/2016
Indianola:4	1.25	1/1/2013	Gaylord GT:3	14.7	1/1/2016
Jackson MO:3	1	1/1/2013	Gaylord GT:4	17	1/1/2016
Jackson MO:4	1	1/1/2013	Genesco IL:3	2.8	1/1/2016
Jackson MO:5	0.6	1/1/2013	Glencoe:7	3.2	1/1/2016
Jackson MO:6	1	1/1/2013	Green River:3	71	1/1/2016
Kaw Plant:2	41.9	1/1/2013	Green River:4	102	1/1/2016
Kennett MO:1	0.4	1/1/2013	Hancock GT:6	49	1/1/2016
Kennett MO:2	0.4	1/1/2013	Hoisington:7	4	1/1/2016
Kennett MO:3	0.8	1/1/2013	Indianola:5	4	1/1/2016
Kennett MO:5	1.4	1/1/2013	James De Young:3	10.5	1/1/2016
Kennett MO:6	2	1/1/2013	James De Young:4	20.5	1/1/2016
Kennett MO:7	2.5	1/1/2013	James De Young:5	27	1/1/2016
Kennett MO:8	3.1	1/1/2013	Knox Lee:4	79	1/1/2016
Kingman KS:2	2	1/1/2013	L Street Jet:1	22	1/1/2016
Knox Lee:2	31	1/1/2013	Lebanon:7	6	1/1/2016
Knox Lee:3	32	1/1/2013	Middletown:10	22.023	1/1/2016
Lake Mills:4	1.3	1/1/2013	Northeast (MI):2	20	1/1/2016
Lake Mills:5	0.9	1/1/2013	Northeast (MI):3	20	1/1/2016
Lake Road MO:1	21.7	1/1/2013	Northeast (MI):4	20	1/1/2016
Lamoni:2	0.2	1/1/2013	Northeastern:3	460	1/1/2016
Lamoni:3	0.3	1/1/2013	Port Jefferson:GT1	16.9	1/1/2016
Lamoni:4	0.55	1/1/2013	Prairie Creek:2	20.7	1/1/2016
Lamoni:5	1.07	1/1/2013	Pulliam:6	72.3	1/1/2016
Larsen:2	14	1/1/2013	Richland:2	14	1/1/2016
Larsen:3	13	1/1/2013	Richland:3	14	1/1/2016
Lebanon:1	0.7	1/1/2013	River Hills:1	18.8	1/1/2016
Lebanon:3	1.3	1/1/2013	River Hills:2	18.8	1/1/2016
Lebanon:4	1.3	1/1/2013	River Hills:3	18.8	1/1/2016
Lebanon:5	2	1/1/2013	River Hills:4	18.8	1/1/2016
Lebanon:6	3	1/1/2013	River Rouge:1	234	1/1/2016

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Lee:1	80	1/1/2013	River Rouge:2	260	1/1/2016
Lee:2	80	1/1/2013	River Rouge:3	280	1/1/2016
Lee:3	257	1/1/2013	S A Carlson:5	22.1	1/1/2016
Lieberman:1	25	1/1/2013	Shawnee:10	127	1/1/2016
Lieberman:2	26	1/1/2013	Shoreham GT:2	20.2	1/1/2016
Louisiana 2:10	40	1/1/2013	Superior GT:1	19	1/1/2016
Louisiana 2:11	40	1/1/2013	Superior GT:2	19	1/1/2016
Louisiana 2:12	58	1/1/2013	Superior GT:3	18	1/1/2016
Maddox:3	10	1/1/2013	Superior GT:4	20	1/1/2016
Maquoketa 1:5	1.5	1/1/2013	Suwannee Riv:ST3	73	1/1/2016
Maquoketa 1:6	2.4	1/1/2013	Trenton Channel:7	111	1/1/2016
Marshall MI:2	0.9	1/1/2013	Trenton Channel:8	100	1/1/2016
Marshall MI:4	0.7	1/1/2013	Trenton Channel:9	524	1/1/2016
Marshall MI:5	1.4	1/1/2013	Twin Falls (MI)	7.6	1/1/2016
Mistersky:5	44	1/1/2013	Valero DE City:1	29.5	1/1/2016
Mora MN:2	1.2	1/1/2013	Valero DE City:2	29.5	1/1/2016
Murray Gill EC:1	40	1/1/2013	Wayne NE:5	3.25	1/1/2016
Mustang:1	50	1/1/2013	Willmar:2	6.5	1/1/2016
Mustang:2	51	1/1/2013	Harding Street:3	40	3/1/2016
Myrtle Beach GT:2	10	1/1/2013	Harding Street:4	40	3/1/2016
Myrtle Beach GT:3	20	1/1/2013	Rolling Hills Gen:1	180	3/1/2016
N Plant IA Wave:5	1.2	1/1/2013	Rolling Hills Gen:2	180	3/1/2016
N Plant IA Wave:6	1.3	1/1/2013	Kraft:1	48	4/1/2016
N Plant IA Wave:7	3.5	1/1/2013	Kraft:2	52	4/1/2016
NE City 1:2	1	1/1/2013	Kraft:3	101	4/1/2016
NE City 1:3	2	1/1/2013	Kraft:4	115	4/1/2016
NE City 1:4	2.7	1/1/2013	Northeastern:4	460	4/1/2016
New Prague:1	1	1/1/2013	Eagle Valley LFG:IC1	1.504	4/30/2016
New Prague:3	2.4	1/1/2013	Astoria GT:2-1	46.2	5/1/2016
New Prague:5	0.6	1/1/2013	Astoria GT:2-2	44.3	5/1/2016
NorthBranch:1	0.82	1/1/2013	Astoria GT:2-3	44.3	5/1/2016
Northeast IN:1	12	1/1/2013	Astoria GT:2-4	42.3	5/1/2016
Oglesby:1	15.75	1/1/2013	Astoria GT:3-1	43	5/1/2016
Oglesby:2	15.75	1/1/2013	Astoria GT:3-2	44.8	5/1/2016
Oglesby:3	15.75	1/1/2013	Astoria GT:3-3	44.3	5/1/2016
Oglesby:4	15.75	1/1/2013	Astoria GT:3-4	44.7	5/1/2016
Osage IA:5	3.1	1/1/2013	Astoria GT:4-1	45.2	5/1/2016
OsageCity:2	0.9	1/1/2013	Astoria GT:4-2	43.8	5/1/2016

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
OsageCity:3	1.1	1/1/2013	Astoria GT:4-3	43.7	5/1/2016
Ottawa KS:3	3.2	1/1/2013	Astoria GT:4-4	44.4	5/1/2016
Ottawa KS:4	3	1/1/2013	B L England:2	155	5/1/2016
Perry K 4 & HS:4	7.37	1/1/2013	Riverside BG&E:4	79	6/1/2016
Plant Crisp:GT1	4	1/1/2013	Riverton:12	150	6/1/2016
Plant X:1	38	1/1/2013	Riverton:7	38	6/1/2016
Plant X:2	91	1/1/2013	Riverton:8	54	6/1/2016
Port Everglds:ST3	389	1/1/2013	Riverton:9	12	6/1/2016
Port Everglds:ST4	394	1/1/2013	Rolling Hills Gen:3	180	6/1/2016
Pratt:3	5.8	1/1/2013	Rolling Hills Gen:4	180	6/1/2016
Princeton (MN):5	1.07	1/1/2013	Lauderdale:1	40	12/1/2016
Princeton (MN):6	2.87	1/1/2013	Lauderdale:10	40	12/1/2016
Rantoul IL:1	0.8	1/1/2013	Lauderdale:11	40	12/1/2016
Rantoul IL:2	0.8	1/1/2013	Lauderdale:12	40	12/1/2016
Rantoul IL:3	0.8	1/1/2013	Lauderdale:13	40	12/1/2016
Rantoul IL:4	0.7	1/1/2013	Lauderdale:14	40	12/1/2016
Rex Brown:3	70	1/1/2013	Lauderdale:15	40	12/1/2016
Rutland GT:5	14.48	1/1/2013	Lauderdale:16	40	12/1/2016
S O Purdom:1	10	1/1/2013	Lauderdale:17	40	12/1/2016
South Hampton:1	10.9	1/1/2013	Lauderdale:18	40	12/1/2016
Southwestern:1	78	1/1/2013	Lauderdale:19	40	12/1/2016
Stallings 1-4:1	22.25	1/1/2013	Lauderdale:2	40	12/1/2016
Stallings 1-4:2	22.25	1/1/2013	Lauderdale:20	40	12/1/2016
Stallings 1-4:3	22.25	1/1/2013	Lauderdale:21	40	12/1/2016
Stallings 1-4:4	22.25	1/1/2013	Lauderdale:22	40	12/1/2016
Suwannee Riv:ST1	30	1/1/2013	Lauderdale:23	40	12/1/2016
Sweatt:1	46	1/1/2013	Lauderdale:24	40	12/1/2016
Sweatt:2	46	1/1/2013	Lauderdale:3	40	12/1/2016
Teche:1	18	1/1/2013	Lauderdale:4	40	12/1/2016
Vinton IA:1	1.2	1/1/2013	Lauderdale:5	40	12/1/2016
Vinton IA:5	0.5	1/1/2013	Lauderdale:6	40	12/1/2016
Vinton IA:6	2.5	1/1/2013	Lauderdale:7	40	12/1/2016
Wayne NE:1	0.75	1/1/2013	Lauderdale:8	40	12/1/2016
Wayne NE:2	0.9	1/1/2013	Lauderdale:9	40	12/1/2016
Wayne NE:3	1.75	1/1/2013	Port Everglds:1	40	12/1/2016
Wayne NE:4	1.85	1/1/2013	Port Everglds:10	40	12/1/2016
Weleetka:1	4	1/1/2013	Port Everglds:11	40	12/1/2016
Williston:3	5.4	1/1/2013	Port Everglds:12	40	12/1/2016

Unit Name	Capacity (MW)	Retirement Date	Unit Name	Capacity (MW)	Retirement Date
Winnetka:4	9.4	1/1/2013	Port Evergids:2	40	12/1/2016
Winnetka:6	6.3	1/1/2013	Port Evergids:3	40	12/1/2016
Wyandotte:4	11.5	1/1/2013	Port Evergids:4	40	12/1/2016
Yazoo:2	5.6	1/1/2013	Port Evergids:5	40	12/1/2016
Warren Co. RR:1	8.98	1/9/2013	Port Evergids:6	40	12/1/2016
Crystal River 3	859	2/1/2013	Port Evergids:7	40	12/1/2016
Hamilton Moses:1	68	2/1/2013	Port Evergids:8	40	12/1/2016
Hamilton Moses:2	67	2/1/2013	Port Evergids:9	40	12/1/2016
Ritchie:1	300	2/1/2013	Sutherland:1	29.5	12/1/2016
Tyrone:3	73	2/1/2013	Sutherland:3	79	12/1/2016
CABOT:6	9.32	3/1/2013	Fox Lake:1	13.2	12/31/2016
CABOT:8	9.34	3/1/2013	Fox Lake:3	85.7	12/31/2016
Cape Fear:1	39	3/1/2013			

Appendix B: New Units

Unit Name	Capacity (MW)	In-Service Date	Unit Name	Capacity (MW)	In-Service Date
Kittyhawk Energy Project (AL)	2.8	6/30/2014	Volkswind Nebraska Wind Project	100.0	12/31/2014
John L McClellan Memorial Veterans Hospital Solar	1.8	7/15/2014	Grande Prairie Wind Farm	100.0	7/31/2015
Hartford Hospital Cogeneration	1.4	5/31/2014	Broken Bow Wind	73.1	12/31/2014
065015 CT	1.1	6/15/2014	Prairie Breeze Wind	200.6	12/31/2014
Cargill Falls Hydroelectric Project	0.5	3/19/2016	Verdigre Wind Farm	79.9	12/31/2015
Cargill Falls Hydroelectric Project	0.4	3/19/2016	Clean Power Berlin	29.0	12/31/2014
Mansfield Hollow Hydro	0.5	6/16/2017	Jericho Mountain	8.6	6/30/2014
Wind Colebrook North	1.6	1/1/2016	Newark Energy Center (NJ)	735.0	6/30/2015
Wind Colebrook North	1.6	1/1/2016	West Deptford Power Project	650.0	6/30/2014
Wind Colebrook North	1.6	1/1/2016	CPV Woodbridge Energy Center	700.0	3/31/2016
Coye Hill Wind	20.0	1/1/2015	Medford Township Sewer Treatment Plant Solar	1.5	1/15/2014
Garrison Energy Center	309.2	6/30/2015	KDC Solar Branchburg	8.0	8/15/2014
North County Regional Resource	95.0	5/31/2015	RC Cape May Solar Project	4.7	9/15/2014
Riviera	1295.0	4/1/2014	Warfield II Solar Project	20.0	6/30/2014
Shady Hills Generating Station	259.0	6/30/2015	Mountain Creek Solar Facility	4.6	4/30/2015
Shady Hills Generating Station	259.0	6/30/2015	CPV Woodbridge Energy Center	1.5	3/31/2016
Port Everglades	1277.0	6/30/2016	Brahms Wind	9.9	2/7/2014
Polk Station	580.0	1/1/2017	Brahms Wind	9.9	2/7/2014
Polk Station	580.0	1/1/2017	Mescalero Ridge Wind Project	320.0	6/1/2017
Clewiston Biorefinery	30.0	1/31/2015	Mescalero Ridge Wind Project	180.0	12/31/2019
Babcock Ranch Solar	75.0	12/31/2014	Taylor Biomass Gasification Project	12.0	12/1/2015
Dahlberg (GA)	190.0	12/31/2014	Taylor Biomass Gasification Project	9.0	12/1/2015
Dahlberg (GA)	190.0	12/31/2014	State Univ (NY) Potsdam Cogeneration	1.4	4/22/2014

Unit Name	Capacity (MW)	In-Service Date	Unit Name	Capacity (MW)	In-Service Date
Dahlberg (GA)	190.0	12/31/2014	State Univ (NY) Potsdam Cogeneration	1.4	4/22/2014
Dahlberg (GA)	190.0	12/31/2014	Astoria Gas Turbines	260.0	6/30/2016
Forsyth County Biomass	50.0	10/31/2014	Astoria Gas Turbines	260.0	6/30/2016
Plant Carl	28.0	1/1/2015	Gowanus Gas Turbines	88.0	6/30/2016
Vogtle (GA)	1117.0	1/1/2018	Astoria Gas Turbines	260.0	6/30/2017
Vogtle (GA)	1117.0	11/30/2018	Astoria Gas Turbines	260.0	6/30/2017
Minor Shoal	0.5	12/8/2018	AES Westover	0.0	6/30/2014
Minor Shoal	0.5	12/8/2018	AES Westover	0.0	6/30/2014
Minor Shoal	0.2	12/8/2018	AES Westover	0.0	6/30/2014
Plant Washington	850.0	12/31/2017	AES Westover	0.0	6/30/2014
Green Energy Resource Center	5.8	9/1/2014	AES Westover	0.0	6/30/2014
Green Energy Resource Center	5.8	9/1/2014	AES Westover	0.0	6/30/2014
Green Power Solutions (GA)	56.0	12/31/2015	Skidmore College (NY) Solar	2.1	6/30/2014
Nelson Energy Center	285.3	10/31/2014	Eagle Creek Hydro	0.8	1/31/2014
Nelson Energy Center	285.3	10/31/2014	Potsdam West Dam Hydro Project	2.5	3/6/2014
Rockford Solar Project	17.0	11/30/2016	Roosevelt Island Tidal Energy Project	0.3	6/1/2015
Marseilles Lock & Dam Project	2.6	1/1/2020	Roosevelt Island Tidal Energy Project	0.6	12/31/2015
Marseilles Lock & Dam Project	2.6	1/1/2020	Roosevelt Island Tidal Energy Project	0.2	1/1/2015
Marseilles Lock & Dam Project	2.6	1/1/2020	School Street	11.0	2/15/2017
Marseilles Lock & Dam Project	2.6	1/1/2020	Orangeville Wind Farm (NY)	92.8	3/28/2014
Dogtown Wind LLC	100.0	12/31/2014	Monticello Hills Wind	18.5	12/31/2014
Dogtown Wind LLC	100.0	6/30/2014	Roaring Brook Wind Farm	78.0	10/31/2015
Cardinal Point Wind Farm	200.0	9/30/2014	Marsh Hill Wind	16.2	10/31/2014
K4 Iroquois County Wind Farm	70.5	8/1/2014	Black Creek LFG	1.6	1/1/2014
Midland Wind Farm	104.0	12/31/2014	Twin Oaks Landfill	1.6	12/31/2015
Meridian Wind Farm (IL)	33.0	10/31/2014	ReVenture Park	1.4	6/30/2014
Meridian Wind Farm (IL)	100.0	11/30/2014	NC 1	0.4	1/23/2014
Meridian Wind Farm (IL)	150.0	12/31/2014	NC 1	0.7	1/23/2014
Ford Ridge Wind Project	100.5	12/31/2015	Garrell Solar Farm	5.0	2/15/2014
Hoopeston Wind Project	86.0	3/31/2015	Dogwood Solar Power Project	20.0	1/6/2014
Green River Wind	20.7	9/30/2015	Daniel Farm	5.0	3/27/2014
K4 Ford County Wind Farm	100.0	8/1/2015	Marshville Farm Solar	6.0	1/15/2014

Unit Name	Capacity (MW)	In-Service Date	Unit Name	Capacity (MW)	In-Service Date
K4 Kankakee County Wind Farm	132.0	6/30/2015	McKenzie Farm Solar	5.0	1/15/2014
Walnut Ridge Wind Farm	105.0	12/31/2016	Moore Solar Farm	5.0	2/12/2014
Green River Wind	121.9	3/30/2016	Nash 58 Farm	6.4	1/15/2014
Walnut Ridge Wind Farm	210.0	6/30/2016	Roxboro Farm Solar	5.0	3/14/2014
Merom	3.3	8/31/2014	Waco Farm Solar	6.4	1/15/2014
Merom	3.3	8/31/2014	Wagstaff Farm 1	5.0	1/15/2014
Merom	3.3	8/31/2014	Yanceyville Farm Solar	5.0	1/30/2014
Merom	3.3	8/31/2014	510 REPP One	1.4	12/15/2014
Lilly Technical Center	1.0	1/31/2014	Angel Solar	6.2	6/15/2014
HQC Maywood	8.0	3/31/2014	Austin Solar	2.5	6/15/2014
Union Township Solar Project	1.0	8/31/2014	Battleground Solar I	4.3	6/30/2014
Southside Solar (IN)	10.0	6/30/2014	Buddy Solar	5.0	7/31/2014
Southside Solar (IN)	10.0	6/30/2014	Charlie Solar	5.8	6/30/2014
Southside Solar (IN)	10.0	6/30/2014	Cornwall Solar Center LLC	6.4	12/31/2014
Indianapolis Intl Arpt Solar Farm	2.5	12/31/2014	Rams Horn Solar Center	22.0	5/20/2014
Indianapolis Intl Arpt Solar Farm	7.5	12/31/2014	Upchurch Solar Center	23.2	7/15/2014
Hertzler Systems Solar Project	13.3	7/31/2014	Van Slyke Solar Center	6.4	7/15/2014
Lenape Solar I	1.0	5/31/2014	Holstein Solar	20.0	10/15/2014
Lenape Solar II	4.0	5/31/2014	Kristen Energy Solar	4.9	7/31/2014
Bluff Point Wind Farm	60.0	12/31/2018	Milo Solar	3.7	7/31/2014
Headwaters Wind Farm	200.0	12/31/2014	Morgan Solar	2.5	7/15/2014
Metro Methane Recovery Facility	1.6	5/31/2014	Biscoe Solar	6.5	6/30/2014
Metro Methane Recovery Facility	1.6	5/31/2014	Montgomery Solar	21.5	12/31/2014
Metro Methane Recovery Facility	1.6	5/31/2014	Wake Solar	2.6	12/31/2014
Victory Wind Farm	100.0	12/31/2014	Owen Solar	6.1	8/15/2014
Huxley Wind (Optimum)	3.0	12/31/2016	RJ Solar	6.2	7/31/2014
Optimum Wind	3.0	12/31/2014	Greenville Farm	20.0	8/15/2014
Carroll Area Wind Farm	20.7	12/31/2014	Laurel Hill Farm	5.0	8/15/2014
Wellsburg Wind Project	138.7	12/31/2014	Smithfield Arpt Ground Solar 1	2.0	5/15/2014
Optimum Wind	3.0	12/31/2015	BGE Carolina Solar I	3.0	9/15/2014
Venus Wind 3	3.0	4/1/2015	Duplin Solar I	5.0	5/15/2014
Lundgren Project	250.0	12/31/2015	Duplin Solar II	5.0	7/15/2014
Macksburg Wind Project	117.5	12/31/2015	Wayne Solar I	5.0	6/15/2014
Vienna Wind Farm	43.7	12/31/2015	Martin Creek Farm	3.0	6/30/2014
Leonardo Wind 1	3.0	4/1/2015	Moncure Farm Solar	5.0	5/15/2014
Leonardo Wind 3	3.0	4/1/2015	Mount Olive Solar Farm	6.4	6/15/2014
Highland Wind Energy	500.0	12/31/2015	Sigmon Catawba Farm	5.0	5/15/2014

Unit Name	Capacity (MW)	In-Service Date	Unit Name	Capacity (MW)	In-Service Date
Optimum Wind	3.0	12/31/2016	Wayne Farm 1 Solar	5.0	6/1/2014
Optimum Wind	3.0	12/31/2017	Wayne Solar III	5.0	8/15/2014
Optimum Wind	3.0	12/31/2018	W Kerr Scott Hydroelectric Project	2.0	7/31/2017
Jameson Energy Center (Jes)	12.3	6/30/2014	W Kerr Scott Hydroelectric Project	2.0	7/31/2017
Jameson Energy Center (Jes)	12.3	6/30/2014	ALP Generation Biomass	5.4	12/31/2014
Jameson Energy Center (Jes)	12.3	6/30/2014	ALP Generation Biomass	5.4	12/31/2014
Rubart Station	9.2	5/31/2014	ALP Generation Biomass	5.4	12/31/2014
Rubart Station	9.2	5/31/2014	ALP Generation Biomass	5.4	12/31/2014
Rubart Station	9.2	5/31/2014	Pioneer Generation Station	45.0	2/1/2014
Rubart Station	9.2	5/31/2014	Pioneer Generation Station	45.0	3/1/2014
Rubart Station	9.2	5/31/2014	Lonesome Creek Station	45.0	1/31/2015
Rubart Station	9.2	5/31/2014	Lonesome Creek Station	45.0	1/31/2015
Rubart Station	9.2	5/31/2014	Rough Rider Wind Farm	175.0	10/31/2014
Rubart Station	9.2	5/31/2014	New Frontier Wind Energy Project	102.0	9/30/2014
Rubart Station	9.2	5/31/2014	Merricourt Wind Project	150.0	3/31/2015
Rubart Station	9.2	5/31/2014	JustWIND Logan County Project	266.4	5/31/2016
Rubart Station	9.2	5/31/2014	Sunflower Wind Project	75.6	12/31/2015
Rubart Station	9.2	5/31/2014	Sunflower Wind Project	34.4	12/31/2015
Wamego	3.2	7/31/2014	JustWIND Logan County Project	100.8	3/31/2015
Riverton	243.0	6/1/2016	Bison Wind Project	204.8	12/31/2014
Fort Hays State University Wind Farm	2.1	2/4/2014	Thunder Spirit Wind Project	150.0	12/31/2014
Fort Hays State University Wind Farm	2.1	2/4/2014	Antelope Hills Wind Project	172.0	12/31/2015
Ringneck Prairie Wind Generation	70.0	12/31/2014	Border Winds Project	150.0	12/31/2015
Western Plains Wind Project	200.1	12/31/2015	Oregon Energy Center (OH)	800.0	9/30/2016
Doyle North 1	200.0	12/31/2015	Rolling Hills Generating LLC	707.0	9/15/2016
Doyle North 2	60.0	12/31/2015	Rolling Hills Generating LLC	707.0	9/15/2016
Marshall Wind Project (KS)	54.0	12/31/2014	Napoleon Biogas Facility	1.4	6/15/2014
Marshall Wind Project (KS)	20.0	12/31/2014	Napoleon Biogas Facility	1.4	6/15/2014
Alexander Wind Farm	48.3	10/31/2015	Battery Utility of Ohio	0.0	3/31/2014
Buckeye Wind Energy Center Project	200.0	12/31/2016	Russell Point Wind Farm	4.0	1/22/2014
Buffalo Dunes Wind Project	180.0	6/1/2016	Hardin Wind Farm	300.0	12/31/2015
Waverly Wind Farm LLC	200.0	12/31/2018	Buckeye Wind Project	140.0	6/30/2015
Pearl Hollow Landfill	0.8	12/31/2015	Black Fork Wind Farm	201.6	10/31/2015

Unit Name	Capacity (MW)	In-Service Date	Unit Name	Capacity (MW)	In-Service Date
Pearl Hollow Landfill	0.8	12/31/2015	Timber Road Wind Farm	50.4	5/15/2014
Cane Run	690.0	5/31/2015	Nexgen North Perry Wind	3.0	6/15/2014
Cannelton Ohio River	29.3	5/31/2014	Charles D Lamb Energy Center	103.0	4/30/2015
Cannelton Ohio River	29.3	5/31/2014	Chisholm View Wind	98.8	12/31/2015
Cannelton Ohio River	29.3	5/31/2014	Mustang Run Wind	141.0	12/31/2014
Meldahl Hydroelectric Project	35.0	12/31/2014	Chilocco Wind Farm	76.5	12/31/2014
Meldahl Hydroelectric Project	35.0	12/31/2014	Chilocco Wind Farm	76.5	12/31/2014
Meldahl Hydroelectric Project	35.0	12/31/2014	Origin Wind Energy Project	150.0	12/31/2014
Smithland	25.3	1/31/2015	Mammoth Plains Wind Farm	198.9	12/31/2014
Smithland	25.3	1/31/2015	Kay Wind Farm Project	299.0	12/31/2015
Smithland	25.3	1/31/2015	Osage County Wind Project	150.0	12/31/2015
Convent ITM Plant	4.3	6/15/2014	Balko Wind Project	200.0	12/31/2015
Morgan City	64.0	6/1/2015	Balko Wind Project	100.0	12/31/2015
Cobscook Bay OCGen Tidal	5.0	7/31/2014	Goodwell Wind I	66.7	12/31/2015
Pisgah Mountain Wind	1.8	6/30/2014	Goodwell Wind II	66.7	12/31/2015
Pisgah Mountain Wind	1.8	6/30/2014	Goodwell Wind III	66.7	12/31/2015
Pisgah Mountain Wind	1.8	6/30/2014	Seiling Wind Project	198.9	12/31/2015
Pisgah Mountain Wind	1.8	6/30/2014	Arbuckle Mountain Wind Farm	100.0	1/31/2016
Pisgah Mountain Wind	1.8	6/30/2014	Hickory Run Energy Station	900.0	1/1/2017
Passadumkeag Windpark	42.0	12/31/2014	Moxie Liberty Project	468.0	12/31/2016
Saddleback Ridge Wind Project	33.0	11/15/2014	Moxie Liberty Project	468.0	12/31/2016
Kibby Wind Power	33.0	10/15/2014	Moxie Patriot Generation	472.0	6/30/2016
Oakfield Wind Farm	147.6	10/31/2015	Moxie Patriot Generation	472.0	6/30/2016
Energy Answers Fairfield	39.3	3/31/2015	Greene Energy Resource Recovery	600.0	9/30/2015
Energy Answers Fairfield	39.3	3/31/2015	Caln Township Solar	10.0	2/15/2015
Energy Answers Fairfield	39.3	3/31/2015	PA Solar Park	10.6	6/30/2014
Energy Answers Fairfield	39.3	3/31/2015	Sustainable Energy Lititz Solar	2.0	3/31/2015
CPV St Charles	746.0	12/31/2016	Meadville Power Station	90.0	1/15/2015
Church Hill Solar Farm	6.0	5/1/2016	County Ground Wind Farm	16.0	6/15/2014
Fourmile Ridge Wind	60.0	12/31/2014	Little Bay	1.3	2/11/2014
Great Bay Wind Energy Center	100.0	12/31/2014	Royal Mills Hydroelectric Project	0.2	6/30/2016
Great Bay Wind Energy Center	50.0	12/31/2014	Block Island Wind	30.0	12/31/2016
Stony Brook (MA)	302.0	7/1/2015	V C Summer	1117.0	3/31/2018

Unit Name	Capacity (MW)	In-Service Date	Unit Name	Capacity (MW)	In-Service Date
Salem Harbor	692.0	6/30/2016	V C Summer	1117.0	3/31/2019
Pioneer Valley Energy Center	400.0	6/30/2016	Orangeburg County Biomass	35.0	12/1/2014
Maynard Solar	1.2	1/1/2014	White Wind Farm Project	204.0	11/30/2014
Winchendon Solar	2.3	3/7/2014	B & H Community Wind Farm	40.7	12/31/2014
Ponterril Solar	3.0	6/30/2014	Campbell County Wind (SD)	99.0	12/30/2015
Leicester Solar	5.0	5/31/2014	B & H Community Wind Farm	38.9	12/31/2015
ACE Boston Solar	2.0	12/15/2014	Chestnut Ridge Gas Recovery	1.6	11/30/2014
Lancaster Solar Project	5.9	6/30/2014	Watts Bar Nuclear	1269.9	12/31/2015
SunGen Mark Andover	5.6	6/15/2014	Lewis Creek	513.0	6/30/2015
Indian Orchard Solar Facility	3.9	5/31/2014	Chamisa Caes Project	135.0	9/30/2015
ACE Cape Cod Solar	18.0	1/15/2015	Chamisa Caes Project	135.0	9/30/2015
Crocker Dam	0.0	12/31/2015	Woodville Biomass Plant	50.0	12/31/2014
Byron Weston Dam Defiance Mill	0.2	2/1/2016	South Plains Wind Energy	200.0	7/31/2015
Springfield Biomass Plant	38.0	7/15/2016	South Plains Wind Energy	300.0	12/31/2015
Camp Edwards Wind	1.7	1/1/2014	Grandview Wind Farm	211.2	12/31/2014
Camp Edwards Wind	1.7	1/1/2014	Happy Hereford Wind Farm	200.0	9/30/2014
Cape Wind	468.0	12/31/2014	Happy Hereford Wind Farm	100.0	12/31/2014
Lynn Wastewater Treatment Plant	0.6	12/31/2014	Happy Hereford Wind Farm	99.9	12/31/2014
Rogers City Power Plant	300.0	12/31/2015	Pantex Renewable Energy Project	11.5	7/31/2014
Rogers City Power Plant	300.0	12/31/2015	Hereford 2 Wind Farm	299.7	9/1/2015
Pheasant Run Wind II	74.8	2/7/2014	Wake Wind Farm	300.0	4/30/2015
Beebe Community Wind Farm	19.2	12/31/2014	Happy Hereford Wind Farm	300.0	4/30/2015
Beebe Community Wind Farm	31.2	12/31/2014	Charlotte Solar (VT)	2.2	7/15/2014
Fowler Farms LLC	64.0	6/30/2014	Open View Solar Farm	2.0	8/15/2014
DTE Oliver/Chandler Wind Park	94.4	10/31/2014	Whitcomb Farm Solar	2.2	10/31/2014
Cross Winds Energy Park	105.4	12/31/2014	Coventry Solar Project	2.6	8/1/2014
Big Turtle Wind Farm	20.0	10/31/2014	Ball Mountain Hydro	0.2	12/31/2014
Big Turtle Wind Farm	30.0	10/31/2014	Ball Mountain Hydro	0.2	12/31/2014
Fairmont Energy Station	6.3	5/31/2014	Ball Mountain Hydro	0.2	12/31/2014
Fairmont Energy Station	6.3	5/31/2014	Ball Mountain Hydro	0.2	12/31/2014
Fairmont Energy Station	6.3	5/31/2014	Ball Mountain Hydro	0.2	12/31/2014
Fairmont Energy Station	6.3	5/31/2014	Ball Mountain Hydro	0.2	12/31/2014
Black Oak Wind Farm (MN)	12.6	9/30/2014	Ball Mountain Hydro	0.2	12/31/2014
Getty Wind Project	40.0	9/30/2014	Ball Mountain Hydro	0.2	12/31/2014
Geronimo Goodhue Wind	95.0	9/30/2014	Ball Mountain Hydro	0.2	12/31/2014
Paynesville Wind	95.0	12/31/2014	Ball Mountain Hydro	0.2	12/31/2014
Prairie Wind Energy Project	98.4	12/31/2014	Ball Mountain Hydro	0.2	12/31/2014

Unit Name	Capacity (MW)	In-Service Date	Unit Name	Capacity (MW)	In-Service Date
Lake Country Wind Energy	41.0	6/30/2014	Ball Mountain Hydro	0.2	12/31/2014
West Stevens Wind	20.0	3/31/2015	Townshend Dam	0.5	12/31/2014
Noble Flat Hill Windpark I	201.0	12/31/2015	Townshend Dam	0.5	12/31/2014
Noble Flat Hill Windpark I	201.0	6/30/2016	Fair Haven Energy Center	34.0	6/30/2015
Pleasant Valley Wind (Res)	176.0	10/31/2015	Deerfield Wind	30.0	3/1/2015
Pleasant Valley Wind (Res)	24.0	10/31/2015	Ciba CHP Facility	10.0	5/16/2015
Sibley County Wind Project	19.5	9/30/2014	Ciba CHP Facility	10.0	5/16/2015
Lakeswind Power Plant	48.0	9/30/2014	Ciba CHP Facility	10.0	5/16/2015
Odell Wind Farm	200.0	12/31/2015	Brunswick County Power Station	1358.0	6/30/2016
Plant Ratcliffe	839.8	5/31/2014	Warren Power Generating	1329.0	2/28/2015
Fredericktown Energy Center	13.8	6/30/2014	Gathright Hydroelectric	3.7	3/13/2017
Fredericktown Energy Center	13.8	6/30/2014	Jennings Randolph Dam Hydroelectric Project	7.0	12/31/2015
Butler Solar Power Farm	2.8	3/11/2014	Jennings Randolph Dam Hydroelectric Project	7.0	12/31/2015
O’Fallon Solar Project	5.7	12/31/2014	Willow Island Hydroelectric	22.0	1/31/2015
Mill Creek Wind Farm	200.0	12/31/2015	Willow Island Hydroelectric	22.0	1/31/2015
Terry Bundy Generating Station	1.6	1/31/2014	Beech Ridge Wind Farm (WV)	49.5	6/30/2014
Terry Bundy Generating Station	1.6	1/31/2014	Oshkosh Foundation Rosedale Biodigester LLC	2.2	1/31/2014
Terry Bundy Generating Station	1.6	1/31/2014	Badger (New)	4.0	2/4/2014
Bluff Road Landfill	1.3	6/30/2014	Randolph Wind Farm	30.0	11/1/2014
Bluff Road Landfill	1.3	6/30/2014	Wood Violet	50.0	7/31/2014
Bluff Road Landfill	1.3	6/30/2014	Highland Wind Farm	102.5	12/31/2014

Appendix C: Emissions Control Projects

Unit Name	Control Project	In-Service Date
Clay Boswell 4	Novel Integrated Desulfurization	2016
Newton (IL) 1	FGD	2015
Newton (IL) 2	FGD	2015
E D Edwards 1	FGD	2015
E D Edwards 2	FGD	2015
D E Karn 1	Dry Lime FGD	2014
D E Karn 2	Dry Lime FGD	2014
Genoa No3 ST3	ACI & SNCR	2015
John P Madgett 1	ACI & SCR & Dry Lime FGD	2014
Monroe (MI) 1	Wet Lime FGD	2014
Monroe (MI) 2	SCR & Wet Lime FGD	2014
Cayuga 1	SCR & DSI	2014
Cayuga 2	SCR & DSI	2015
Baldwin Energy Complex 1	Baghouse	2013
Baldwin Energy Complex 2	Baghouse	2013
Scherer 1	SCR & FGD	2014
Scherer 2	SCR & FGD	2014
Scherer 4	FGD	2014
Yates 6	SCR & Wet Lime FGD	2015
Yates 7	SCR & Wet Lime FGD	2015
Lansing Smith 1	FGD	2018
Homer City Station 1	ACI & Baghouse & Dry Lime FGD	2014
Homer City Station 2	ACI & Baghouse & Dry Lime FGD	2014
Merom 1	SCR & Electrostatic Precipitator & Wet Limestone	2014
Rockport 1	SCR & FGD	2017
Rockport 2	SCR & FGD	2019
Harding Street 7	Baghouse & FGD	2017
Lansing 4	FGD	2015
Ottumwa (IA IPL) 1	Baghouse & FGD	2014
La Cygne 1	Baghouse & Wet Limestone	2015
La Cygne 2	SCR & Baghouse & Wet Limestone	2015
E W Brown 3	SCR	2014
Big Cajun 2 ST1	ACI & Baghouse & Electrostatic Precipitator	2014
Big Cajun 2 ST2	ACI	2014
Big Cajun 2 ST3	ACI & Baghouse & Electrostatic Precipitator	2015
George Neal North 3	Baghouse & Flue Desulferization	3/31/2014
George Neal South 4	Baghouse & Flue Desulferization	12/31/2013
Walter Scott Jr Energy Center ST1	Dry Lime FGD	2/28/2014
Midland Cogeneration Venture CC	Steam Injection	3/31/2014
Joliet 29 7	Other	2018
Joliet 29 8	Other	2018
Joliet 9 6	Other	2018
Powerton 5	Other	2018
Powerton 6	Other	2018
Waukegan 7	DSI	2015
Waukegan 8	DSI	2015
Victor J Daniel Jr 1	Wet Limestone	2015

Unit Name	Control Project	In-Service Date
Victor J Daniel Jr 2	Wet Limestone	2015
Michigan City 12	Wet Limestone	2018
R M Schahfer 14	Dual Alkali & FGD	2013
R M Schahfer 15	SNCR & Dual Alkali & FGD	2013
Sherburne County 1	ACI & SCR & Baghouse & Dry Lime FGD	2014
Sherburne County 2	ACI & SCR & Baghouse & Dry Lime FGD	2014
Sherburne County 3	SCR	2014
Big Stone ST1	SCR	2015
Big Stone ST1	Dry Lime FGD	2015
Hoot Lake 2	Other	2015
Hoot Lake 3	Other	2015
Northeastern 3	Baghouse & DSI	2016
Cross 2	FGD	2014
Winyah 3	Electrostatic Precipitator	2014
Flint Creek (AR) 1	ACI & SCR & Baghouse & FGD	2016
Allen Steam Plant (TN) 1	Electrostatic Precipitator & FGD	2018
Allen Steam Plant (TN) 2	Electrostatic Precipitator & FGD	2018
Allen Steam Plant (TN) 3	Electrostatic Precipitator & FGD	2018
Gallatin (TN) 1	SCR & Electrostatic Precipitator & FGD	2017
Gallatin (TN) 2	SCR & Electrostatic Precipitator & FGD	2017
Gallatin (TN) 3	SCR & Electrostatic Precipitator & FGD	2017
Gallatin (TN) 4	SCR & Electrostatic Precipitator & FGD	2017
Shawnee (KY) 1	SCR & FGD	2017
Shawnee (KY) 4	SCR & FGD	2017
Jeffrey Energy Center 1	SCR	2014
Jeffrey Energy Center 2	SCR	2016
Lawrence Energy Center (KS) 3	Electrostatic Precipitator	2013
Lawrence Energy Center (KS) 4	Baghouse & Wet Limestone	2013
Lawrence Energy Center (KS) 5	Wet Limestone	2013
D B Wilson UN1	Wet Lime FGD	2016
Kenneth Coleman GEN1	ACI & DSI	2016
Kenneth Coleman GEN2	ACI & DSI	2016
Kenneth Coleman GEN3	ACI & DSI	2016
Robert D Green GEN2	SCR	2015
South Oak Creek 7	SCR	2014
South Oak Creek 8	SCR	2014
Columbia (WI) 1	ACI & Baghouse & FGD	2014
Columbia (WI) 2	Baghouse & FGD	2014
Edgewater (WI) 5	Baghouse & FGD	2016
Weston 3	Other	2016

Appendix D: Fuel Price Inputs

($/MMBtu)	Henry Hub	Kerosene/Jet Fuel	Fuel Oil#2 (Distillate)	Fuel Oil#6 - 0.7%
Jan-14	5.19	23.51004	23.49	19.4
Feb-14	4.99	23.43775	23.35	19.31
Mar-14	4.64	23.67068	23.19	19.3
Apr-14	4.45	23.60643	23.26	19.65
May-14	4.27	23.61446	23.08	19.29
Jun-14	4.3	23.40562	22.69	19.52
Jul-14	4.44	22.92369	22.39	19.32
Aug-14	4.57	22.99598	22.44	19.2
Sep-14	4.51	23.09237	22.74	19.48
Oct-14	4.58	22.84337	22.95	19.44
Nov-14	4.93	22.69076	22.93	19.37
Dec-14	5.12	22.56225	22.84	19.35
Jan-15	5.18	22.39357	22.99	19.21
Feb-15	5.03	22.37751	22.91	19.07
Mar-15	4.74	22.34538	22.57	19.01
Apr-15	4.6	22.4739	22.84	19.34
May-15	4.47	22.73896	22.88	18.99
Jun-15	4.54	22.77108	22.68	19.18
Jul-15	4.67	22.58635	22.61	18.93
Aug-15	4.8	22.53815	22.56	18.74
Sep-15	4.74	22.53815	22.82	18.94
Oct-15	4.89	22.50602	23.22	18.88
Nov-15	5.22	22.24096	23.15	18.68
Dec-15	5.46	22.12851	23.14	18.57
Jan-16	4.662745	17.71837	19.41274	11.98789
Feb-16	4.629053	17.66322	19.24098	11.71484
Mar-16	4.542271	17.72547	19.13553	11.77582
Apr-16	4.302344	17.86118	19.136	12.07405
May-16	4.317659	18.02766	19.16784	12.46406
Jun-16	4.341141	18.25176	19.25942	12.88915
Jul-16	4.380958	18.45191	19.39305	13.08786
Aug-16	4.401378	18.89374	19.97355	13.17307
Sep-16	4.404441	19.36884	20.65998	13.14085
Oct-16	4.442216	19.41002	20.90482	13.06688
Nov-16	4.538187	19.01317	20.69674	12.89984
Dec-16	4.735233	18.45533	20.26175	12.601
Jan-17	4.865191	17.51717	19.17478	12.46026

($/MMBtu)	Henry Hub	Kerosene/Jet Fuel	Fuel Oil#2 (Distillate)	Fuel Oil#6 - 0.7%
Feb-17	4.834405	17.46264	19.00512	12.17645
Mar-17	4.75231	17.52418	18.90096	12.23984
Apr-17	4.516285	17.65835	18.90142	12.54982
May-17	4.531678	17.82294	18.93288	12.9552
Jun-17	4.557333	18.04449	19.02334	13.39703
Jul-17	4.59838	18.24237	19.15533	13.60358
Aug-17	4.618904	18.67919	19.72871	13.69214
Sep-17	4.621983	19.14889	20.40673	13.65866
Oct-17	4.659952	19.1896	20.64856	13.58177
Nov-17	4.762572	18.79726	20.44303	13.40814
Dec-17	4.967811	18.24576	20.01337	13.09753
Jan-18	5.212668	17.70593	19.35593	12.56785
Feb-18	5.182079	17.65081	19.18467	12.2816
Mar-18	5.100509	17.71302	19.07953	12.34553
Apr-18	4.886387	17.84864	19.07999	12.65818
May-18	4.904741	18.015	19.11175	13.06706
Jun-18	4.93329	18.23894	19.20306	13.51272
Jul-18	4.975095	18.43895	19.3363	13.72104
Aug-18	4.995487	18.88048	19.91509	13.81037
Sep-18	5.000586	19.35524	20.59952	13.7766
Oct-18	5.039331	19.39639	20.84364	13.69905
Nov-18	5.149451	18.99982	20.63617	13.52392
Dec-18	5.365612	18.44237	20.20245	13.21063
Jan-19	5.321309	18.2802	19.83513	12.85721
Feb-19	5.291594	18.2233	19.65963	12.56436
Mar-19	5.212354	18.28752	19.55189	12.62976
Apr-19	5.004349	18.42753	19.55236	12.94961
May-19	5.024159	18.59929	19.5849	13.36791
Jun-19	5.051893	18.8305	19.67848	13.82382
Jul-19	5.094484	19.037	19.81501	14.03694
Aug-19	5.115285	19.49284	20.40814	14.12833
Sep-19	5.121228	19.983	21.10951	14.09378
Oct-19	5.160848	20.02548	21.35967	14.01445
Nov-19	5.268813	19.61606	21.14706	13.83529
Dec-19	5.486723	19.04053	20.70261	13.51478
Jan-20	5.201841	18.74952	20.28804	13.21251
Feb-20	5.174222	18.69115	20.10854	12.91157
Mar-20	5.100572	18.75703	19.99833	12.97878
Apr-20	4.907241	18.90063	19.99882	13.30747
May-20	4.927495	19.0768	20.0321	13.73733

($/MMBtu)	Henry Hub	Kerosene/Jet Fuel	Fuel Oil#2 (Distillate)	Fuel Oil#6 - 0.7%
Jun-20	4.955113	19.31394	20.12781	14.20584
Jul-20	4.996541	19.52574	20.26746	14.42485
Aug-20	5.016795	19.99329	20.87413	14.51877
Sep-20	5.022319	20.49604	21.59152	14.48326
Oct-20	5.059144	20.53961	21.84739	14.40173
Nov-20	5.162254	20.11967	21.62993	14.21762
Dec-20	5.369395	19.52936	21.17532	13.88826
Jan-21	5.360017	19.25337	20.75598	13.53285
Feb-21	5.333916	19.19343	20.57234	13.22461
Mar-21	5.262813	19.26108	20.45959	13.29346
Apr-21	5.078305	19.40854	20.46009	13.63011
May-21	5.098106	19.58945	20.49414	14.07039
Jun-21	5.125107	19.83296	20.59206	14.55026
Jul-21	5.165609	20.05045	20.73493	14.77458
Aug-21	5.18541	20.53056	21.35559	14.87078
Sep-21	5.19081	21.04682	22.08953	14.83441
Oct-21	5.226811	21.09156	22.3513	14.7509
Nov-21	5.334816	20.66034	22.12882	14.56233
Dec-21	5.546324	20.05417	21.66373	14.22498
Jan-22	5.409563	19.81089	21.2441	13.9718
Feb-22	5.385472	19.74922	21.05613	13.65356
Mar-22	5.317501	19.81883	20.94073	13.72464
Apr-22	5.141121	19.97056	20.94124	14.07222
May-22	5.136819	20.15671	20.97609	14.52678
Jun-22	5.164351	20.40727	21.07632	15.02221
Jul-22	5.201348	20.63106	21.22255	15.25381
Aug-22	5.237485	21.12507	21.85781	15.35312
Sep-22	5.246949	21.65628	22.609	15.31557
Oct-22	5.29427	21.70232	22.87693	15.22936
Nov-22	5.397517	21.25861	22.64922	15.03467
Dec-22	5.599709	20.63489	22.17319	14.68638
Jan-23	5.534435	20.26337	21.67606	14.25897
Feb-23	5.511073	20.20029	21.48427	13.9342
Mar-23	5.445161	20.27149	21.36652	14.00673
Apr-23	5.263275	20.42669	21.36705	14.36145
May-23	5.25076	20.61708	21.4026	14.82536
Jun-23	5.284134	20.87337	21.50486	15.33098
Jul-23	5.32585	21.10227	21.65407	15.56733
Aug-23	5.363396	21.60757	22.30225	15.66869
Sep-23	5.375911	22.15091	23.06872	15.63036

($/MMBtu)	Henry Hub	Kerosene/Jet Fuel	Fuel Oil#2 (Distillate)	Fuel Oil#6 - 0.7%
Oct-23	5.430143	22.198	23.34209	15.54238
Nov-23	5.530263	21.74415	23.10975	15.34369
Dec-23	5.726332	21.10619	22.62405	14.98824
Jan-24	5.738408	20.72364	22.11357	14.58488
Feb-24	5.715417	20.65913	21.91791	14.25268
Mar-24	5.650546	20.73194	21.79779	14.32687
Apr-24	5.46579	20.89067	21.79832	14.6897
May-24	5.453472	21.08539	21.8346	15.16421
Jun-24	5.486318	21.34749	21.93892	15.68138
Jul-24	5.527375	21.5816	22.09114	15.92314
Aug-24	5.564327	22.09837	22.7524	16.02681
Sep-24	5.576644	22.65405	23.53434	15.98761
Oct-24	5.630018	22.70221	23.81323	15.89762
Nov-24	5.73266	22.23806	23.5762	15.69439
Dec-24	5.925629	21.5856	23.08069	15.33081
Jan-25	5.876709	21.14524	22.52522	14.86897
Feb-25	5.853163	21.07941	22.32592	14.5303
Mar-25	5.786729	21.1537	22.20355	14.60594
Apr-25	5.59752	21.31566	22.2041	14.97583
May-25	5.584906	21.51434	22.24105	15.45958
Jun-25	5.618543	21.78178	22.34732	15.98683
Jul-25	5.660589	22.02065	22.50237	16.2333
Aug-25	5.698431	22.54793	23.17594	16.33899
Sep-25	5.711045	23.11492	23.97243	16.29903
Oct-25	5.765706	23.16406	24.25652	16.20728
Nov-25	5.870822	22.69046	24.01508	16.00009
Dec-25	6.068441	22.02473	23.51034	15.62943

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