Power Sector Trends

Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

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U.S. Environmental Protection Agency

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Introduction

The purpose of this technical support document (TSD) is to review the recent historical trends shaping the electric power sector. For this TSD, electricity generation will be categorized across four primary fuel sources: nuclear, renewables (which include hydro, wind, solar, etc.), natural gas, and coal. There are other fuel sources for electricity, like petroleum, but these other sources represent less than 2% of annual generation.

In 2021, the majority of electricity from the power sector came primarily from fossil fuel sources, with natural gas as the primary fuel source (at 37% of total generation), followed by coal-fired generation (22%). Most of the remaining electricity delivered to the U.S. came from low/zero emitting sources, including renewable and nuclear sources, at 20% each, and the remaining 1% of generation coming from other generating sources including petroleum.

In 2021, 43% of capacity was from natural gas fuel sources, 18% from coal, 25% from renewables, and 9% from nuclear. The differences in overall shares between generation and capacity are driven by the operation of the EGUs by fuel source and whether they have higher or lower capacity factors. For example, nuclear generation was 19% of generation, but only 9% of operating capacity at the end of 2021 because nuclear units typically operate at relatively higher loads (i.e., at higher capacity factors) as baseload units. Conversely generation shares are lower than capacity share for fuel sources like natural gas (38% and 43% respectively). Natural gas EGUs operate more flexibly and at lower capacity factors.

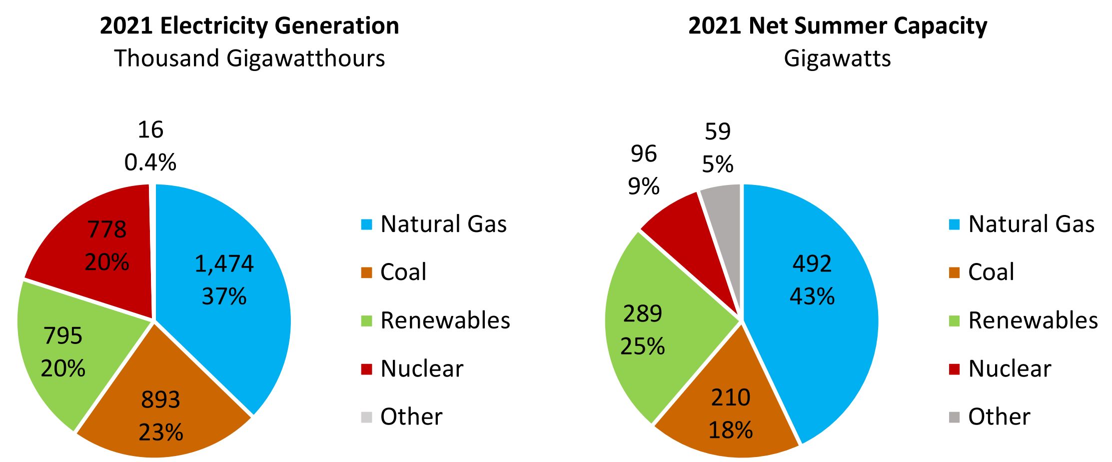

Figure 1: U.S. electricity generation and capacity shares by fuel type, 2021

Source: EIA, Monthly Energy Review, Table 7.2B Electricity Net Generation: Electric Power Sector, May 2022, www.eia.gov/totalenergy/data/monthly/, and EIA, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

Electricity generation from coal-fired EGUs has declined in recent years. Despite the fact that electricity demand has continued to increase over time, with total electricity generation increasing by 8% between 2000-2021, supply of electricity generation from coal-fired EGUs has declined by 54% over the same time period, starting at 1,943 thousand GWh in 2000, peaking in 2007 at 1,998 thousand GWh, and declining to 893 thousand GWh by 2021. Coal-fired EGUs delivered 53% of total generation in 2000 and 23% in 2021. It's only within the last decade, starting in 2016, that coal generation was surpassed by another fuel source, natural gas. In 2022, renewable generation also surpassed coal generation[1] and it's also expected that nuclear generation will surpass coal generation within the next year[2].

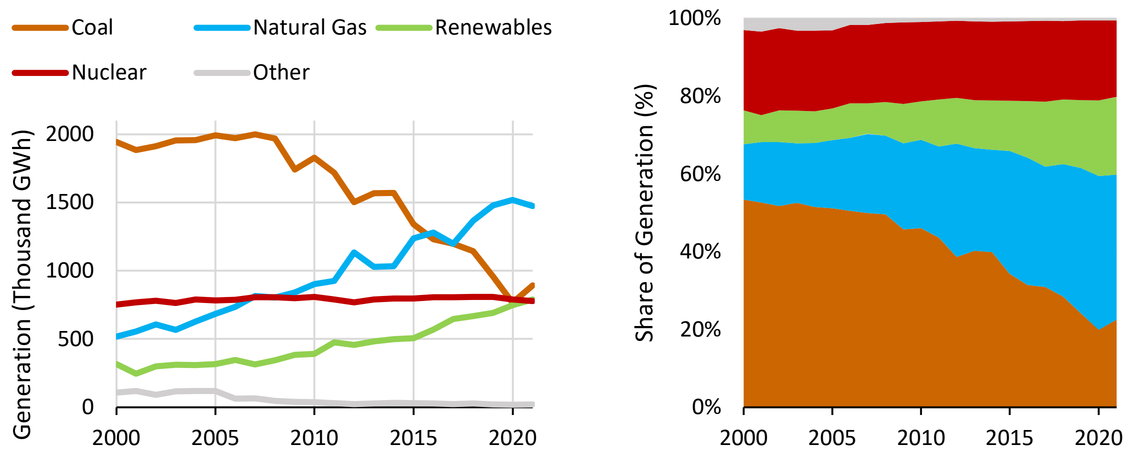

Figure 2: U.S. power sector generation and generation shares by fuel type, 2000-2021
Source: EIA, Monthly Energy Review, Table 7.2B Electricity Net Generation: Electric Power Sector, May 2022, www.eia.gov/totalenergy/data/monthly/

Generation from other sources, primarily natural gas and renewables, has replaced the declines in generation from coal. Generation from natural gas increased from 518 thousand GWh in 2000 to 1,474 thousand GWh in 2021. Generation from renewables increased from 315 thousand GWh in 2000 to 790 thousand GWh in 2021. The vast majority of the increase in renewable generation over that time period came from wind and solar.

This TSD uses recent historical power sector data, as well as an initial set of projections on the future outcomes of the electric power sector, to discuss the major trends occuring in the power sector. The following section begins with a brief background on power sector operations. The focus of power sector trends is then divided into two main sections: first, coal-related trends and the drivers that are leading to the decreases observed in coal capacity and operation and second, natural gas- and renewables-related trends and how they continue to increase to meet capacity and generation needs of the power sector. The final two sections of this TSD cover the state of other generating technologies in the power sector and concluding remarks.

[1] EIA, "Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022," Today In Energy, https://www.eia.gov/todayinenergy/detail.php?id=55960
[2] EIA, Short Term Energy Outlook, https://www.eia.gov/outlooks/steo/data.php

Power Sector Background

Electricity in the U.S. is generated by a range of technologies. The power sector consists of electricity generators that operate in interconnected grid systems, which are usually regional in scale. The electricity generated by these different technologies is transmitted and distributed through a system of interconnected components to end-users, e.g., industrial, business, and residential consumers.

Generation and capacity are commonly reported statistics with key distinctions. Generation is the production of electricity and is a measure of an EGU's *actual* output while capacity is a measure of the maximum *potential* production of an EGU under certain conditions. Capacity is typically measured in megawatts (MW) for individual units or gigawatts (1 GW = 1,000 MW) for multiple EGUs. Generation is often measured in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (1 GWh = 1 million kWh). Net generation is the amount of electricity that is available to the grid from the EGU and excludes the amount of electricity used within the power plant for operations (*e.g.*, ancillary services such as fuel handling equipment and environmental control equipment). In addition to producing electricity for sale to the grid, EGUs perform many services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators.

EGUs are not generally used to produce electricity 100% of the time. In fact, some EGUs only operate during the peak periods of highest demand (or constrained supply) while others are needed to meet daily and seasonal demand fluctuations. In general, the EGUs with the lowest operating costs are dispatched before EGUs with higher operating costs. As a result, an EGU with high fuel costs will typically only operate if other lower-cost plants are unavailable or if there is sufficiently high demand. Units are also unavailable during both routine and unanticipated outages. Unanticipated outages typically become more frequent as power plants age. The utilization of these EGUs is measured by their capacity factor. Capacity factors are calculated by dividing the actual amount of electricity produced by an EGU by the capacity times by the total number of hours within the year. For example, a capacity factor of 50% could mean that a generating unit is operating at full capacity half of the time or at half capacity all of the time.

The production and delivery of electricity to customers consists of three distinct segments: generation, transmission, and distribution. After generators produce their net generation for the grid, electricity is then transmitted over networks[3] of high voltage lines to substations where power is stepped down to a lower voltage for local distribution. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator;[4] in others, individual utilities[5] coordinate the operations of their generation, transmission, and distribution systems to balance the system across their respective service territories.

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[3] These three network interconnections are the Western Interconnection, comprising the western parts of both the U.S. and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the U.S. and Canada (except those parts of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at *https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf.*

[4] For example, PMJ Interconnection, LLC.

[5] For example, Los Angeles Department of Power and Water, Florida Power and Light.

Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers. The transmission and distribution systems are the classic example of a natural monopoly, in part because it is not practical to have more than one set of lines running from the electricity generating sources to substations or from substations to residences and businesses.

During the past few decades, several jurisdictions in the U.S. began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities developed much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission-only utilities, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by utilities separately from the generation of electricity and sometimes separately from the purchase and sale of electricity. Power sector restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission services needed to deliver power to consumers. The resulting wholesale energy, capacity, and ancillary products markets are regulated by the Federal Energy Regulatory Commission (FERC).

On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act (IIJA) (also known as the Bipartisan Infrastructure Law), which allocated more than $70 billion in funding via grant programs, contracts, cooperative agreements, credit allocations, and other mechanisms to develop and upgrade infrastructure and expand access to clean energy technologies. Specific objectives of the legislation are to improve the nation's electricity transmission capacity, pipeline infrastructure, and increase the availability of low-carbon fuels.

The Inflation Reduction Act (IRA), which President Biden signed on August 16, 2022, has the potential for even greater impacts on the electric power sector. With an estimated $369 billion in Energy Security and Climate Change programs over the next 10 years, covering grant funding and tax incentives, the IRA provides investment toward non GHG-emitting generation and away from the fossil fuel-fired units that are the subjects of these proposed regulations. For example, one of the conditions set by Congress for the expiration of the Clean Electricity Production Tax Credits of the IRA, found in section 13701, is a 75% reduction in GHG emissions from the power sector below 2022-levels.

The provisions in the IIJA and the IRA demonstrate a push to reduce GHG emissions through a broad array of additional tax credits, loan guarantees, and public investment programs.

Coal Trends

Coal-fired EGUs were once the primary source of electricity generation for the power sector; however, in recent years the delivery of electricity from coal has declined. Natural gas and renewables have surpassed coal-fired generation. Nuclear will likely surpass coal within the year.

Electricity from coal is delivered primarily through steam turbines that combust pulverized coal.[6] At a coal steam generating unit, the coal is crushed (pulverized) into a powder to increase its surface area. The coal powder is then blown into the combustion chamber of the boiler where it is burned.[7]

In 2021, 208 GW of coal-fired capacity was in operation. Of the remaining coal-fired EGUs the vast majority was built nearly half a century ago. The majority of coal-fired EGUs were installed in the 1970 and 1980 decades, with 102 GW and 69 GW installed respectively. Since 2000, only 21 GW of new coal-fired EGUs have been installed, or 8.5 times less than what was built over a similar time period from 1970-1990 (see Figure 3). Instead, utilities have opted to build new natural gas and renewable capacity. Over the same time-period of 2000-2021, 342 GW of new natural gas and 200 GW of new renewable capacity were installed, or over 25 times more capacity from new natural gas and new renewables as compared to new coal over the same time period (see Natural Gas and Renewables Trends Section).

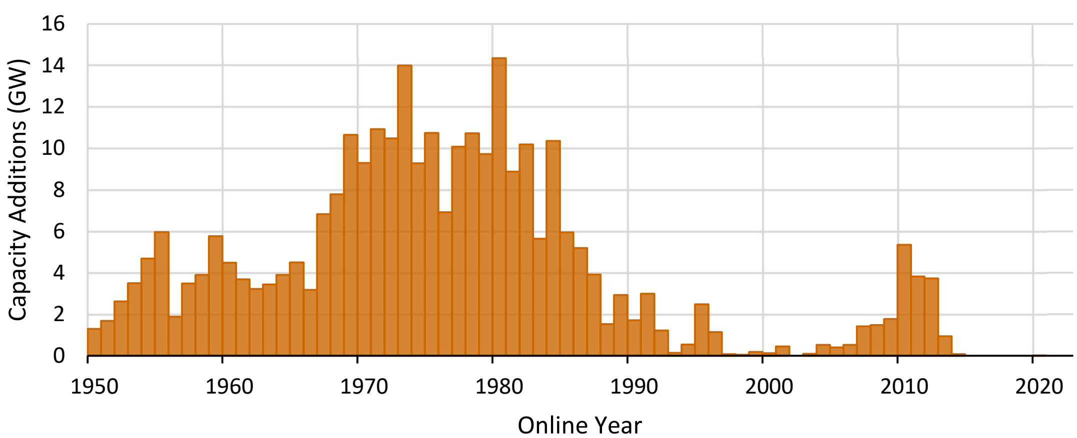


Figure 3: Annual capacity additions of coal, 1950-2021
Source: EIA, Electric Generators Inventory, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

It is unlikely that new conventional coal-fired EGUs will come online in the US. The last year in which a new coal-fired EGU (greater than 25 MW) was completed was in 2014. There are no new announced plans to build new coal-fired EGUs.

In addition to the lack of investment in new coal-fired EGUs, retirements of existing coal-fired EGUs have accelerated in recent years, both in absolute terms and in terms of the share of annual capacity retirements (see Figure 4). Between 2000-2010, 5 GW of coal-fired EGUs retired. Since 2010, 90 GW of coal-fired EGUs have retired. Coal represents the majority of all recent EGU retirements. For example,

[6] Fossil fuel-fired utility steam generating units (*i.e.,* boilers) are most often operated using coal as the primary fuel. However, some utility boilers use natural gas and/or fuel oil as the primary fuel.
[7] There are other, less common combustion technologies, for example, fluidized bed combustion technology. In fluidized bed combustion, the solid fuel is combusted in a layer of heated particles suspended in upward flowing air.

over the past five years, coal-fired EGUs have represented over half of all of the retired capacity in any given year. In 2022, coal-fired EGUs represented nearly 80% of all retired capacity (see Figure 4).

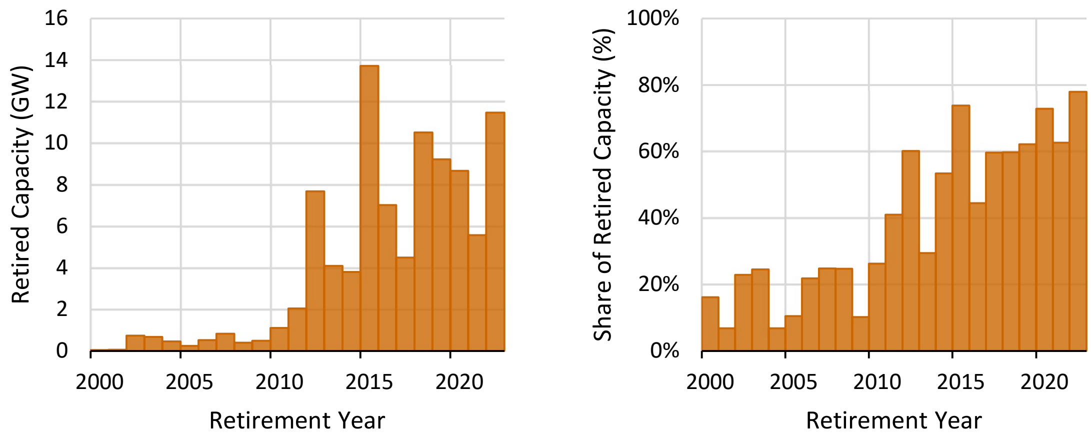


Figure 4: Annual coal retirements and retirement shares, 2000-2022
Source: EIA, Electric Generators Inventory, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

One driver for the observed increases in coal-fired EGU retirement is age. As mentioned earlier, the majority of coal-fired EGUs were installed in the 1970s and 1980s. With little capacity coming online over the past two decade, the average age of the coal-fired EGU fleet has increased over time. The capacity-weighted average age of operating coal-fired EGUs was 28 years old in 2000 and has increased to 43 years old in 2021 (see Figure 5).

As technology progresses, newer technologies coming online operate more efficiently and at lower costs than aging EGUs. The maintenance costs increase and the efficiency of EGUs declines over time as equipment degrades, further hindering cost competitiveness of older EGUs. The average lifetime of different EGUs varies by technology type and retirement decisions are not always motivated by the age of the asset.

The average annual retirement age for coal-fired EGUs for any given year between 2000-2021 was between 47 and 61 years old and the capacity-weighted average retirement age was 50 years (see Figure 6). Given that the average age of coal-fired EGUs in 2021 was 43 years old, this means that half of the operating coal fleet is at most within 7 years of the average age of retirement for coal-fired EGUs. Only 28% of operating coal capacity currently exceeds the average age of retirement.

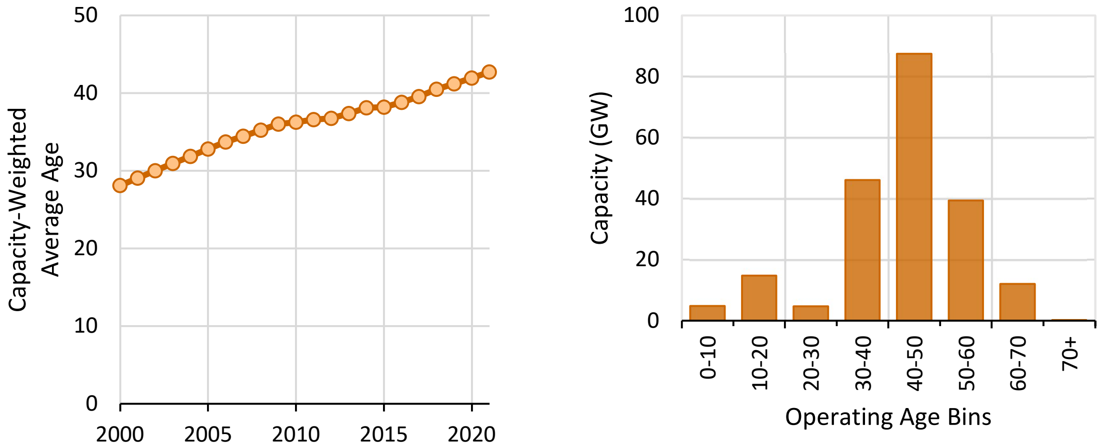


Figure 5: Coal age by operating year, 2000-2021, and total operating coal capacity by age bin, 2021

Source: EIA, Annual Electric Generators Report, Form EIA-860, September 2022, www.eia.gov/electricity/data/eia860/

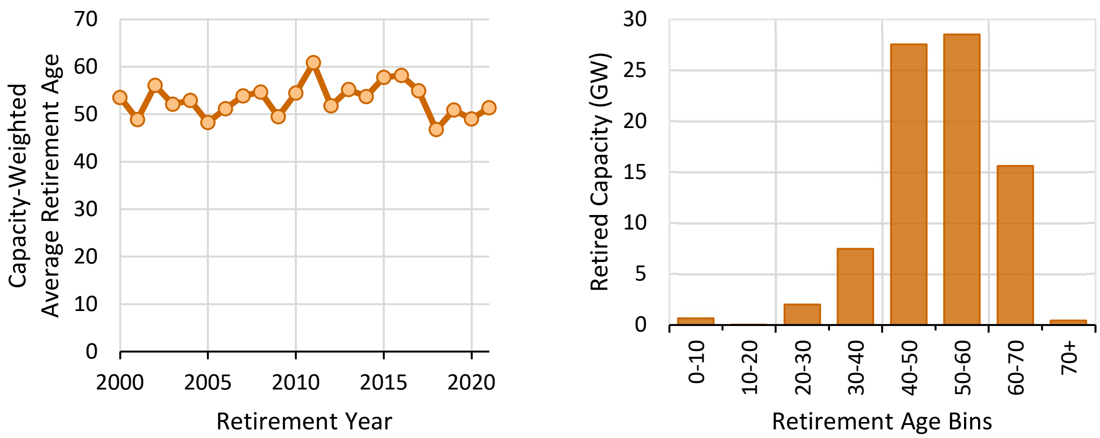


Figure 6: Coal retirement age by year, 2000-2021, and total retired coal capacity by age bin, 2000-2021
Source: EIA, Annual Electric Generators Report, Form EIA-860, September 2022, www.eia.gov/electricity/data/eia860/

Based on utilities' announced plans for coal-fired EGU retirements, this retirement trend is expected to continue. In 2021, there was a little over 200 GW of coal-fired EGUs operating in the power sector. Between 2021 and 2040, utilities have already announced publicly plans to retire a total of 118 GW of coal-fired EGUs, over half of the remaining coal fleet (see Figure 7).

Announced retirements are just one way to measure the future state of the power industry. Many utilities wait to publicly announce the retirement of a facility until its closer to its planned retirement date. Some utilities have announced broad plans to reduce operation of some of their coal-fired EGU fleet but haven't announced which facilities specifically will be the ones to retire by a given date. In either case, coal retirements are expected to continue, likely at a rate above that of announced retirements.

Beyond announced retirements, the age of the EGUs may be considered. In 2021, there were 10 GW of coal-fired EGUs operating on the grid with ages exceeding 50 years (e.g., the average coal-fired EGU retirement age) that did not already have an announced retirement. By 2040, there are an additional 60 GW beyond the 118 GW of coal-fired EGUs with announced retirements that would be at or above the age of 50. Assuming the coal-fired EGUs without announced retirements retire at the average coal retirement age (i.e., age-based retirement), that would lead to a total of 178 GW of coal retirements by 2040 or approximately 82% of the remaining coal fleet (see Figure 7).

Figure 7: Coal capacity by category (announced, age-based, and projected), 2020-2040

Source: EPA, National Electric Energy Data System (NEEDS) v6, www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6 and EPA, Post-IRA 2022 Reference Case, www.epa.gov/power-sector-modeling

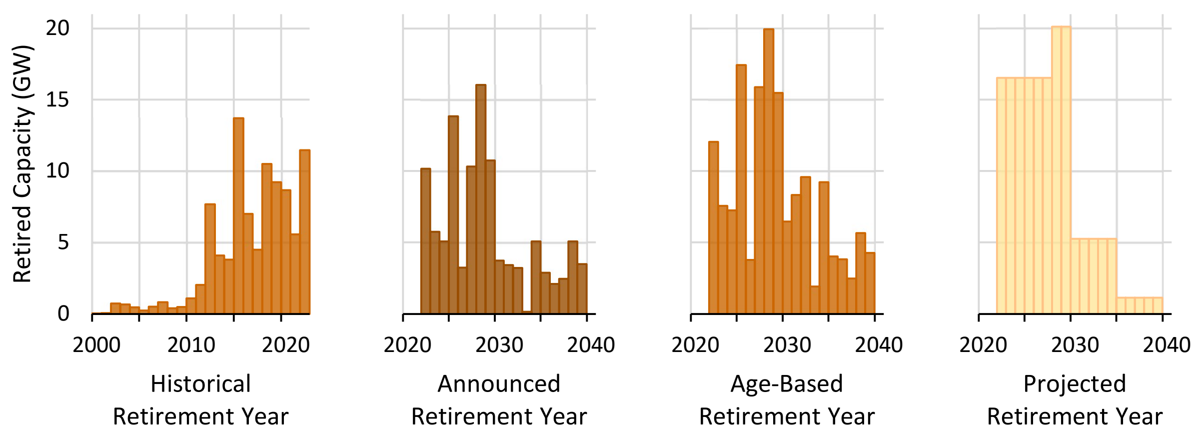


Figure 8: Annual coal retirements by category (historical, announced, age-based, and projected), 2000-2040

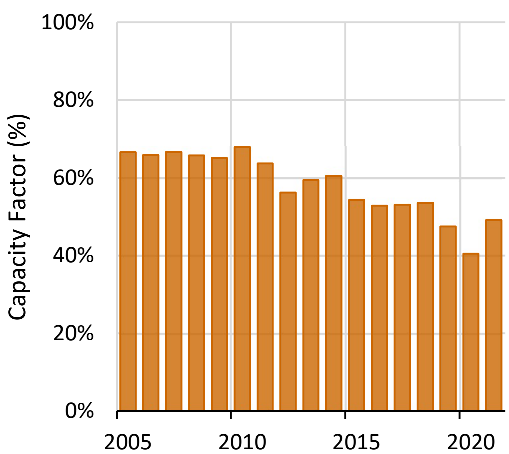
Source: EPA, National Electric Energy Data System (NEEDS) v6, www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6 and EPA, Post-IRA 2022 Reference Case, www.epa.gov/power-sector-modeling

Another data source for coal retirements are model projections of the power sector. Power sector projections provide data out to 2050 on future outcomes of the electric power sector. The projections discussed here are based on a "business as usual" scenario, which includes representation of existing laws and regulations, including the IRA, but absent further proposed regulation. The results are based on

EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case (i.e., Post-IRA 2022 Reference Case).

Power sector projections from the Post-IRA 2022 Reference Case show that coal capacity is expected to decline beyond announced retirements. The projections use announced retirements as an exogenous input into the model; the projections do not use exogenous age-based retirement assumptions. The additional projected retirements beyond the announced retirements are based on economic assumptions and other projected changes and suggest unfavorable market conditions for coal-fired EGUs going forward. Projections show a total of 187 GW of coal retirements by 2040 or nearly 90% of the remaining coal fleet (see Figure 7). Going forward, the provisions in the IRA, like the clean electricity tax credits, make the build out of lower emitting electricity generation more economically favorable than coal-fired generation. Using the same data, the annual rate of coal retirements can also be compared, as shown in Figure 8. In a single year, the maximum historical level of coal retirements occurred in 2015 at 14 GW of capacity. Announced retirements show a maximum of 16 GW in a single year is expected to occur within the next five years in 2028. The two other methods for estimating future coal retirements shown (age-based assumptions and projections), show a maximum of 20 GW of coal capacity retiring within a single year.

Another driver for the decline in coal-fired generation over time is the decrease in the utilization of the operating fleet. Average coal-fired EGU capacity factors have declined over time as coal-fired EGUs have shifted from providing baseload power to, in many cases, providing intermediate power needs. Capacity factors for coal-fired EGUs were at 67% on average in 2005 and have fallen to a low of 41% in 2020 (see Figure 9). In 2021, there was a slight rebound in coal capacity factors, but overall coal capacity factors are expected to continue to decline. Looking at model projections of coal operation, by 2040, the Post-IRA 2022 Reference Case show coal capacity factors falling to an average of 10% across the remaining coal-fired EGU fleet.



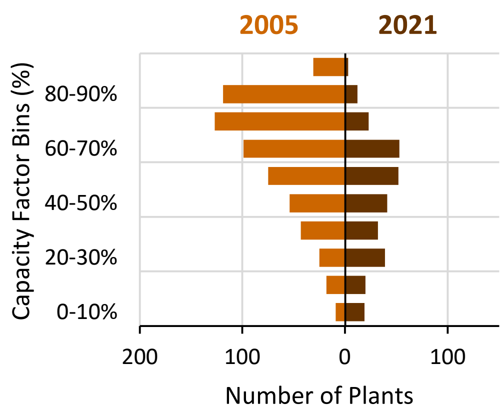


Figure 9: Coal average annual capacity factors and distributions, 2005-2021

Source: EIA, Electric Power Monthly, Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, September 2022, www.eia.gov/electricity/monthly/; EIA, Annual Electric Generators Report, Form EIA-860, September 2022, www.eia.gov/electricity/data/eia860/; EIA, Annual Power Plant Operations Report, Form EIA-923, October 2022, www.eia.gov/electricity/data/eia923/

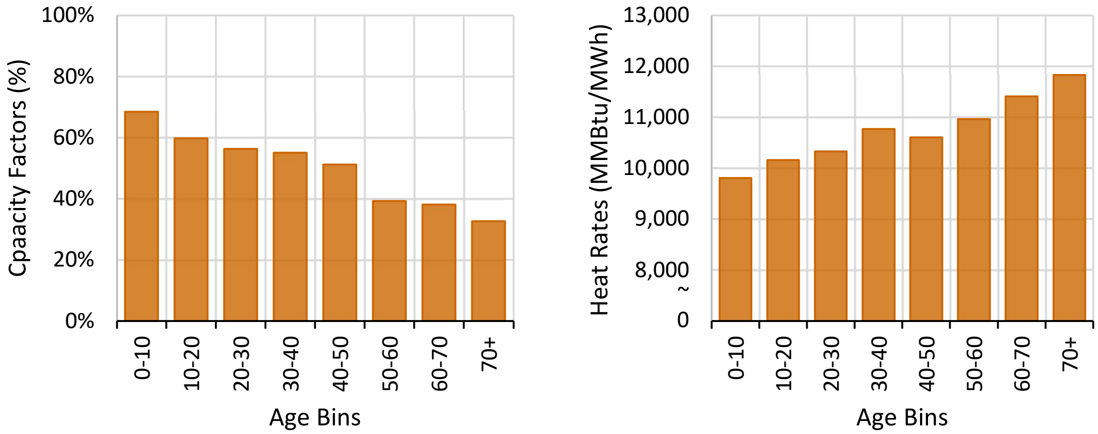


Figure 10: Coal capacity-weighted average annual capacity factors and heat rates by age, 2014-2021
Source: EIA, Annual Electric Generators Report, Form EIA-860, September 2022, www.eia.gov/electricity/data/eia860/ and EIA, Annual Power Plant Operations Report, Form EIA-923, October 2022, www.eia.gov/electricity/data/eia923/

One contributing factor to the decline in coal capacity factors is as coal-fired generators age, they tend to operate less and operate less efficiently. Between 2014-2021, younger coal-fired EGUs between the ages of 10-20 years operated at an annual capacity factor of 60% and at an annual heat rate of 10,159 MMBtu/MWh on average. Older coal-fired EGUs during the same period operated at lower capacity factors and higher heat rates, at 41% and 11,410 MMBtu/MWh on average for coal-fired EGUs between 60-70 years of age (see Figure 10). As mentioned previously (see Figure 5) the average age of coal-fired EGUs has increased from 28 years in 2000 to 43 years in 2021. And given the lack on new coal-fired EGUs coming online, this trend is expected to continue, suggesting that a decrease in capacity factors and a loss in efficiency will likely continue as well.

There are several factors that contribute to the loss in efficiency of coal-fired EGUs as they age. As coal-fired EGUs operate less often, they are often cycling more. Cycling coal-fired EGUs results in higher heat rates, as units are consuming more energy to produce electricity while the units are warming up. As heat rates increase, the emission rates of coal-fired EGUs also increase, since it takes more heat content (i.e., more tons of coal) to deliver the same amount of electricity.

Declines in coal-fired EGUs efficiency as they age also corresponds to declines in investment towards coal-fired EGUs as they age. Annual non-fuel operation and maintenance expenses were on average $43 per kW-year for coal-fired EGUs between 30-50 years of age, based on data collected between 1994-2020. Annual operation and maintenance expenses decline as the EGUs age further, around $33 per kW-year for EGUs between 50-70 years of age on average. In general, annual expense needs for EGUs do not decrease as the EGUs age, rather, the observed 23% decline over time more likely reflects shifting investment priorities.

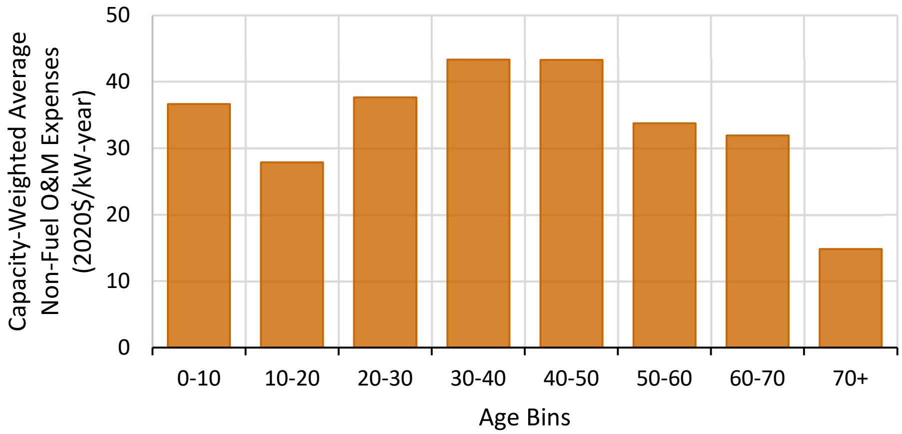


Figure 11: Coal capacity-weighted average annual non-fuel O&M expenses by age, 1994-2020
Source: FERC, Form No. 1 - Annual Report of Major Electric Utility, www.ferc.gov/industries-data/electric/resources/industry-forms/form-no-1-annual-report-major-electric-utility

Factors that contribute to the decline in capacity and operation of coal-fired EGUs are not limited to the trends discussed in this section, but also to the market conditions in which they operate. As natural gas and renewable technologies have declined in costs in recent years, more generation from these sources has entered the market, increasing competition. The following section will explore natural gas and renewable trends in more detail.

Natural Gas and Renewables Trends

Over the past two decades, natural gas generation has increased from 518 thousand GWh in 2000 to 1,474 thousand GWh in 2021 and renewable generation has increased from 315 thousand GWh in 2000 to 790 thousand GWh in 2021 (see Figure 12). This generation increase coincides with an increase in electricity demand as well as a decrease in electricity generation from coal-fired EGUs, as discussed in the previous section. Natural gas and renewables have surpassed coal-fired generation.

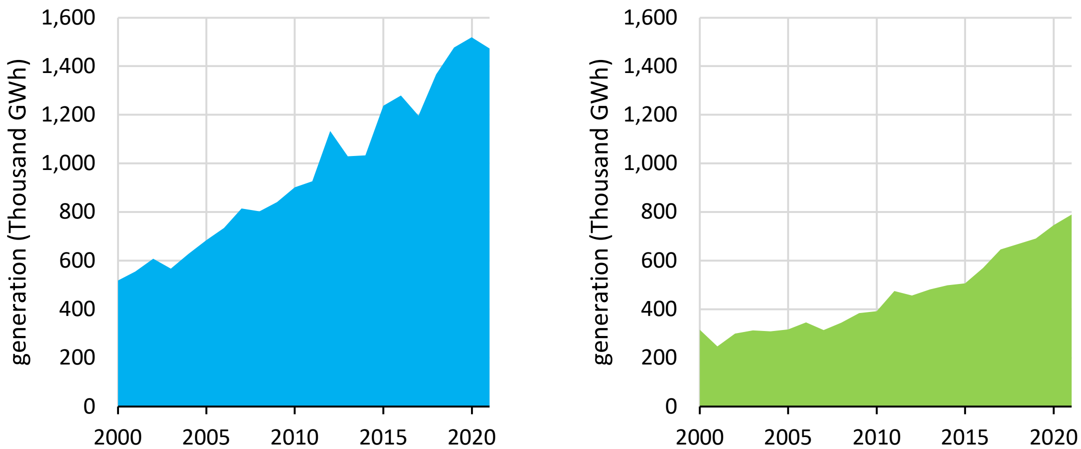


Figure 12: U.S. natural gas and renewable power sector generation, 2000-present

Source: EIA, Monthly Energy Review, Table 7.2B Electricity Net Generation: Electric Power Sector, May 2022, www.eia.gov/totalenergy/data/monthly/

The majority of natural gas consumption in the electric power sector comes from stationary combustion turbines, both simple cycle and combined cycle. Combustion turbines have the capability to burn either gaseous or liquid fuels, although the majority of fuel consumption comes from natural gas. Natural gas can also be consumed at steam turbines (many existing coal- and oil-fired utility boilers have repowered as natural gas-fired units) and, to a lesser degree, internal combustion engines.

Stationary combustion turbine EGUs use one of two configurations: combined cycle (NGCC) or simple cycle combustion turbines (NGCT). NGCC units have two generating components (*i.e.*, two cycles) operating from a single source of heat, a combustion turbine and a heat recovery steam generator. Simple cycle combustion turbines only use a combustion turbine to produce electricity (*i.e.,* there is no heat recovery or steam cycle). NGCC units are more efficient and tend to operate at higher capacity factors; NGCTs are less efficient and are typically used only in times of peak electricity demand.

There has been significant expansion of the natural gas generation in recent years. Since 2000, natural gas generation has increased from 518 thousand GWh in 2000 to 1,474 thousand GWh in 2021. Between 2000 and 2021 there has been 242 GW of new NGCC capacity, 95 GW of new NGCT capacity, and 342 GW of new natural gas capacity in total. In 2021, the net summer capacity of natural gas EGUs totaled 413 GW, with 281 GW being NGCC generation and 132 GW being NGCT generation, with 69% of total natural gas capacity coming online since 2000 (see Figure 13).

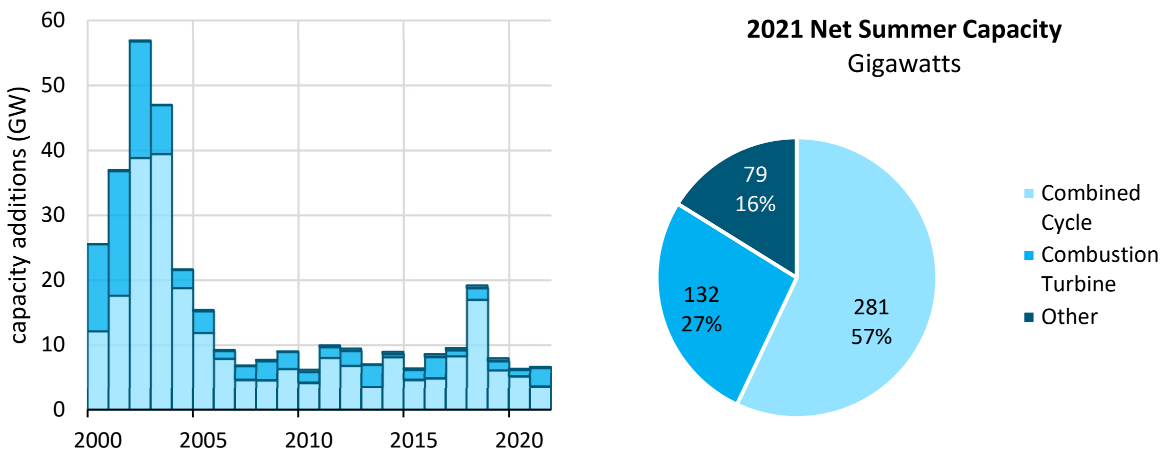


Figure 13: Natural gas capacity installed, 2000-2021, and 2021 share of natural gas capacity by type
Source: EIA, Electric Generators Inventory, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

The Post-IRA 2022 Reference Case projects that the majority of new builds of natural gas capacity will be from NGCT EGUs rather than NGCC EGUs. The reason model projections suggest an increased need of NGCT capacity going forward is due to the increasing deployment of new variable renewable electricity generation and the role NGCTs can play (along with other generating technologies, like energy storage) in balancing these variable renewable electricity resources.

Renewable electricity has also increased substantially in recent years and is expected to continue to grow. The Clean Electricity Production and Investment Tax Credits of the IRA provide financial support for new zero-emitting generation resources. These tax credits are available at full credit value to renewable generating technologies up until the later of 2032 or until there is a 75% reduction in GHG emissions from the power sector below 2022 levels. As these tax credits remain widely available, it is likely the expansion of renewable technologies will continue.

Renewable electricity is a broad category that represents a wide range of energy sources, including sources of energy from water, geothermal, biomass/waste, wind, and solar energy sources. Over the past two decades, renewable generation has more than doubled from 315 thousand GWh in 2000 to 790 thousand GWh in 2021 (see Figure 12). Almost all of the recent growth in renewable generation is attributed to changes in wind and solar generation.

Generation from water, geothermal, biomass/waste renewable resources have not substantially changed in recent years. The majority of conventional hydroelectric capacity was built before the 1980s. In 2021, hydroelectric capacity was at 80 GW and provided 33 percent of the net generation from U.S. renewables, which equates to approximately 7% of total net generation. Geothermal and biomass/waste energy sources combined grew in the 1980s and 1990s after the passage of PURPA[8], but haven't seen significant capacity growth in more recent years. In 2021, together these geothermal and biomass/waste renewable

[8] In 1978, partly in response to fuel security concerns, price spikes, and energy crises that affected the national and global economy, Congress passed the Public Utilities Regulatory Policies Act (PURPA). This legislation provided the impetus for renewable energy development because the act required local electric utilities to buy power from qualifying facilities (QFs). QFs were either cogeneration facilities or small generation resources that use renewables such as wind, solar, biomass, geothermal, or hydroelectric power as their primary fuels. See: Casazza, J. and Delea, F., Understanding Electric Power Systems, IEEE Press, at 220-221 (2d ed. 2010).

resources were at 15 GW of capacity and provided 6% of the net generation from U.S. renewables, which equates to approximately 1% of total net generation.

Since 2000, the majority of new renewable capacity coming online has been in the form of wind and solar capacity (see Figure 14). In 2021, wind provided 48% of renewable generation and 10% of total net generation and solar 14% of renewable generation and 3% of total net power sector generation[9].

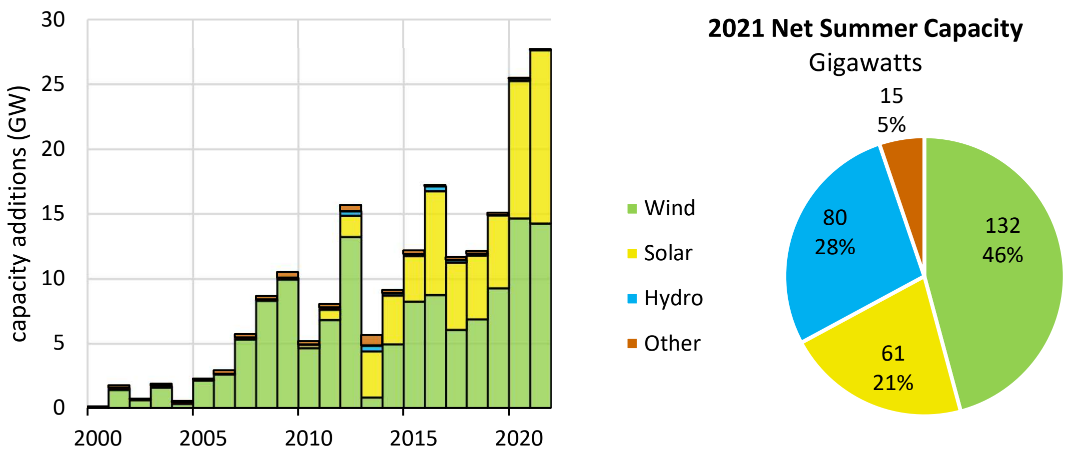


Figure 14: Renewable capacity installed, 2000-2021, and 2021 share of renewable capacity by type
Source: EIA, Electric Generators Inventory, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

Since the fuel sources for wind and solar technologies are essentially free, the main costs incurred by these technologies are in the upfront capital costs to build them. The capital costs of renewable energy sources have fallen over time. The unsubsidized average levelized cost of wind energy from 1988 to 1999 was $106/MWh and since declined to $32/MWh in 2021.[10] The average levelized cost of energy for utility-scale solar photovoltaics has fallen since 2010 from $227/MWh to $33/MWh in 2021.[11] As renewables' total O&M costs are relatively low compared to conventional generating technologies, like coal-fired EGUs that have fuel costs in addition to other O&M costs (see Figure 11), they are often ahead of coal-fired EGUs in the dispatch stack (i.e., the order in which EGUs generate). As more variable renewable energy technologies come online, they push dispatchable generating technologies, like coal-fired EGUs, further down the dispatch stack, leading to lower capacity factors for these conventional EGUs.

Projections of renewable capacity show continued increase, driven by declining costs and continued financial support though the provisions within the IRA. By 2040, projections from the Post-IRA 2022 Reference Case show renewable generation exceeding 60% of total generation.

[9] The generation shares discussed here are based on power sector generation totals. There is also a significant amount of distributed solar generation from end-use sectors not accounted for here.
[10] U.S. Department of Energy (DOE), Land-Based Wind Market Report: 2022 Edition, 2022. See *https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2022-edition*.
[11] Lawrence Berkeley National Laboratory (LBNL), Utility-Scale Solar Technical Brief, 2022 Edition, September 2022. See *https://emp.lbl.gov/utility-scale-solar*.

Other Generating Technologies Trends

The previous sections discussed power sector trends related to coal, natural gas, and renewables. The remaining 19% of electricity generation is served by nuclear (19%) and other (1%) generation technologies. In 2021, there was a total of 96 GW of nuclear capacity operating on the grid and 59 GW of capacity from other generating technologies (see Figure 1). Historical trends show minimal change in nuclear generation in recent years. Nuclear capacity also received financial assistance through the IIJA and IRA. The nuclear fleet is also aging and, like coal, may be impacted by changing market conditions after the availability of the tax credits expire.

There was a total of 59 GW of capacity from other generating technologies operating on the grid at the end of 2021, of which 30 GW came from fossil-fuel based resources (primarily petroleum products) and 28 GW came from energy storage technologies. In terms of, planned capacity additions, nearly all new capacity within the "other" category is expected to come from battery storage, a total of 21 GW of battery capacity to be install from 2022 to 2025.[12] The Post-IRA 2022 Reference Case also shows rapid growth in energy storage capacity, reaching 204 GW by 2040. Although energy storage technologies do not provide net generation to the grid, they do compete with conventional generating technologies, like coal-fired EGUs and natural gas-fired combustion turbines, that also contribute to capacity towards resource adequacy needs.

Conclusion

In 2021, 38% of generation was from natural gas, 23% from coal, 20% from nuclear, 19% from renewables, and 1% from other generating sources. Supply of electricity generation from coal-fired EGUs has declined by 54% between 2000 and 2021. Generation from natural gas and renewables has increased by 184% and 151% between 2000 and 2021, respectively.

The recent decline in coal generation has many contributing factors. The increase in coal retirements corresponds with increasing age, decreasing utilization, decreasing efficiency, and decreasing investment in non-fuel O&M costs seen across coal-fired EGUs. Outside of coal-related trends, the increases in generation from natural gas and renewables, as well as the increase in battery storage capacity, creates additional competition in the energy markets in which coal-fired EGUs participate. With added investment from IIJA and IRA, these trends are expected to continue in the future.

[12] https://www.eia.gov/todayinenergy/detail.php?id=54939