ANALYSIS GROUP

U.S. Coal-Fired Power Generation:

Market Fundamentals as of 2023 and Transitions Ahead

Authors:
Susan F. Tierney, Ph.D.

August 8, 2023
(corrected)

Acknowledgments

This is an independent report prepared by Susan Tierney at the request of Environmental Defense Fund ("EDF"). Sue is a Senior Advisor at Analysis Group, with decades of experience in energy and environmental economics, policy and regulation in the electric and natural gas industries.

The report reflects the analysis and judgment of the author alone and does not necessarily reflect an institutional position of EDF, Analysis Group, or other entities.

About Analysis Group

Analysis Group is one of the largest economic consulting firms globally, with more than 1,200 professionals in 14 offices in North America, Europe, and Asia. Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies.

Analysis Group's energy and environment practice area is distinguished by expertise in economics, finance, market modeling and analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. Members of Analysis Group's practice have worked for a wide variety of clients including: energy producers, suppliers and consumers; utilities; state regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; start-up companies; and others. For more information, visit **www.analysisgroup.com**

Table of Contents

I. Executive Summary

In 2012, Sue Tierney authored a white paper that described trends in retirements of coal plants and pointed to several factors – low natural gas prices, relatively flat electricity demand, and other influences -- that were adversely affecting the economics of coal-fired generation.[1] In 2016, Dr. Tierney authored another paper that described various influences that led to decreases in domestic coal production and coal-mining employment between 2000-2016.[2]

Since those reports came out, the energy market fundamentals that were showing up in 2012 and in 2016 have become even more pronounced. Coal-fired generation declined by nearly another 50% over the past decade, with power supplied from natural gas, wind and solar having made up the difference.[3] The last large new coal power plant to open in the U.S. began operation in 2013.[4] With no other coal plant additions and significant retirements over the past decade, coal-fired generating capacity dropped from just under 300 GW in 2012, to 183 GW by the end of 2023.[5] Coal production[6] and mining employment[7] have also continued to decline.

Three principal factors have led to these more recent outcomes: (1) the economic advantages of producing electricity from natural gas, renewable energy and nuclear facilities, relative to output at many existing coal plants; (2) climate and other related commitments of states and private companies that have favored low-carbon generation; and (3) the continued entry of new gas-fired, wind, solar, and storage capacity. Together, these conditions have put pressure on the availability of coal-fired power plants, their output and their economics, and in turn, on owners' decisions to retire coal plants, especially older and relatively inefficient units around the country.

Fundamental power market economics and dispatch norms constituted the key driver of these outcomes. With additions of new and efficient gas-fired and renewable capacity since 2012, along with relatively low natural gas prices, significant quantities of cost-competitive generating resources (e.g., existing nuclear, gas and renewable units) were dispatched ahead of many coal plants around the U.S. The newer facilities have had improved power-production efficiencies (i.e., lower heat rates), further putting pressure on coal-plant output in many regions.

Actions by private-sector actors and many states have affected these trends. Approximately 80% of all electricity consumers are served by a utility with commitments to reduce carbon emissions, either because the utility operates in a state with a mandatory carbon-reduction target or because the utility itself has made a voluntary commitment.[8] Twenty-two states have requirements affecting power-sector greenhouse gas ("GHG") emissions, and 75% have a renewable portfolio requirement or zero-carbon emissions reduction requirement or both.[9] As of 2022, major American companies have entered into agreements for 68 GW of clean power capacity.[10]

---

[1] https://www.analysisgroup.com/globalassets/content/news_and_events/news/2012_tierney_whycoalplantsretire.pdf.
[2] https://www.analysisgroup.com/globalassets/insights/publishing/2016-tierney-coal-industry-21st-century-challenges.pdf.
[3] Energy Information Administration ("EIA"), Annual Generation data by fuel sources, https://www.eia.gov/electricity/data.php.
[4] Sandy Creek Energy Station (932 MW) in Texas.
[5] EIA, Short Term Energy Outlook, July 11, 2023, Table 7e, https://www.eia.gov/outlooks/steo/. S&P Capital IQ, Historical & Future Power Plant Capacity (Data).
[6] EIA, U.S. coal production amounted to 1,016 million short tons ("ST") in 2012, 728 ST in 2016, and 595 ST in 2022. https://www.eia.gov/coal/data.php#production.
[7] Federal Reserve Bank of St. Louis, data on all employees (coal mining): 41,300 employees in May 2023, compared to 87,400 in May 2012 and 50,000 in May 2016. https://fred.stlouisfed.org/series/CES1021210001.
[8] Smart Electric Power Alliance (SEPA), Utility Carbon-Reduction Tracker, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/,
[9] NARUC/NRRI, State Clean Energy Policy Tracker, https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/.
[10] CEBA Deal Tracker, https://cebuyers.org/deal-tracker/.

Over the past decade, virtually all new capacity additions involved power plants that use natural gas, wind, solar, or water, and energy storage facilities. Of the 221 GW of net capacity additions from 2012-2022, 38% occurred at wind projects (+84 GW), 33% at solar projects (+72 GW), 24% at gas-fired facilities (+54 GW), and 1% at hydropower projects (1.6 GW).[11] Most of this capacity operates with no fuel cost, and thus shifts the power supply curve whenever such capacity is able to operate (e.g., when the sun is shining, or the wind is blowing).

With 294 GW of coal plant capacity as of 2012, these various factors influenced the owners of many coal plants – especially small and older ones – to retire their units. Since the beginning of 2012 through 2023, 138 GW of coal-fired generating capacity has retired,[12] of which 83 GW was owned by electric utilities and the remaining 55 GW was owned by non-utility generating companies.[13]

Many retirement decisions about older and relatively inefficient existing coal facilities were influenced to a lesser degree by federal environmental regulations as well. For example, the final federal Mercury and Air Toxics Standard ("MATS") Rule issued in February 2012 by the U.S. Environmental Protection Agency ("EPA") generally gave coal-fired power plants until early 2016 to comply. Over the four-year period from 2012-2015, 278 coal units retired, totaling 39 GW of capacity with an average size of 141 MW; by contrast, in the years since those regulations went into effect (i.e., 2016-2023), 312 coal-fired power generating units totaling 90 GW and with a larger average unit size (289 MW) retired (and thus were not specifically triggered by MATS regulations).[14]

These trends also happened in the absence of EPA's October 2015 Clean Power Plan ("CPP"), which (a) would have allowed until 2030 for states to implement actions leading to required levels of power-sector emissions but (b) never went into effect starting with the Supreme Court's stay of the rule in February 2016.[15] By that point, and throughout the decade from 2012 onwards, owners of distressed coal plants have had to decide whether it would be economically and financially worthwhile to invest in compliance strategies, given the poor performance levels of some plants, the outlook for continued pressure from competing sources of electricity, and the cost of compliance.

Even without the CPP or other implemented regulations to reduce GHG emissions from the power sector, carbon dioxide emissions as of 2022 are already 34% below 2005 levels, which exceeds the emissions reductions intended to result from the CPP (i.e., 32% below 2005 levels by 2030).

Looking ahead, these same influences – the power system's operating principle of economic dispatch, ongoing progress in meeting states' clean power and climate policies, pursuit by utilities and corporations of their own climate pledges, economic attractiveness of adding new natural gas, wind, and solar technologies – will continue to put pressure on output at coal plants. These impacts will be amplified by the unprecedented federal financial incentives for investment in zero-carbon electric technologies, storage, and energy efficiency that have been introduced in the 2021 Infrastructure Investment and Jobs Act ("IIJA") and the 2022 Inflation Reduction Act ("IRA").

The impact of these two federal statutes can be seen by comparing planned coal-plant retirements from the period before enactment of the IIJA with the current plans for coal-plant retirements. Cumulative planned retirements for the post-2024 period grew by 166% from January 2021 (when the amount was 30.9 GW) to May 2023 (when the amount was 51.2 GW). Assuming these retirements go into effect as planned, 144 GW of coal plant capacity

[11] S&P Global data.
[12] This capacity figure includes actual retirements through May 2023 and planned retirements through the end of 2023.
[13] EIA, Preliminary Monthly Electric Generator Inventory as of May 2023, with data on operating units, planned retirements, and actual retirements, https://www.eia.gov/electricity/data/eia860m/. (Hereafter, "EIA Inventory of Generators".)
[14] EIA Inventory of Generators.
[15] Courtney Scobie, "Supreme Court Stays EPA's Clean Power Plan," American Bar Association, February 17, 2017, https://www.americanbar.org/groups/litigation/committees/environmental-energy/practice/2016/021716-energy-supreme-court-stays-epas-clean-power-plan/#:~:text=On%20February%209%2C%202016%2C%20the,legal%20challenges%20had%20been%20heard.

would be in operation in 2040. Of that amount, 49 GW entered service before 1975 and is already nearly 50 years old. By 2030, if all of this capacity were still operating, more than half of it (74 GW) would be over 50 years old.

As new generating capacity and storage facilities with no or low variable costs enter service and are dispatched ahead of fossil generating units with higher variable costs, the capacity factor of many fossil plants will continue to deteriorate, rendering many of the now-operating coal plants less economic to maintain and less financially viable in the future. Much of this older and less efficient coal-plant capacity with low utilization will likely retire before 2040, although the timing of owners' decisions about individual plants remains uncertain today.

Several things may affect such timing of coal retirements, whether planned or unplanned at present. Many studies examining the transitions underway in U.S. electric systems point to significant changes on the supply side (e.g., expansion of the grid, deployment of utility-scale and small-scale clean-power technologies) and on the demand side (e.g., impacts from electrification of heating systems in buildings and adoption of electric vehicles, and from more flexible demand). The pace of commercial readiness and adoption of some advanced technologies (e.g., advanced nuclear) is uncertain, as is the pace of uptake of conversions to electric heating systems and states' policies affecting retail rate designs. Local reliability considerations may keep even some relatively poor performing coal plants in operation until local electricity needs can be assured through some combination of new generating and/or storage units, energy efficiency, flexible demand, transmission, or other actions.

Another uncertainty affecting the timing of retirements, especially of coal-fired power plants with low utilization rates, is the outcome of the current EPA rulemaking on regulating GHG emissions from existing fossil power plants. As EPA explained about its proposed rule, it offers different approaches to the "Best System of Emission Reduction" for large and frequently used GHG-emitting generating units, on the one hand, and for less frequently used units on the other, depending on the date upon which a particular affected unit is shut down for retirement.

The proposed GHG regulations for existing fossil generating units has features that dovetail with power system and market realities as they now and are anticipated to exist in upcoming years: that is, that some fossil fuel generating units will operate infrequently now and in the years ahead and may be good candidates (e.g., from a financial point of view) for retirements in the not-too-distant future, while other fossil units are likely to show promise for operating in economically viable ways for many years. The flexibility built into the proposed approach recognizes that owners of these generating units make asset investment decisions reflecting multiple considerations – the likelihood that a plant will be called upon to generate power and earn revenues in electricity markets, the plant's likely going-forward profitability given its age and size and location, its importance for reliability purposes, and the value proposition of undertaking one or another compliance strategy in light of all of those factors and the costs of different strategies. As summarized by the Harvard Environmental & Energy Law Program, "If a coal plant plans to operate for a long time (i.e., beyond 2040), EPA is proposing to require those plants to run pollution controls by 2030. But if a company plans to continue to operate a coal plant until 2035 or 2040, then EPA proposes standards based on how much it will run or what fuels it uses. If a plant is planning to retire by 2032, the rule doesn't ask companies to make costly investments."[16]

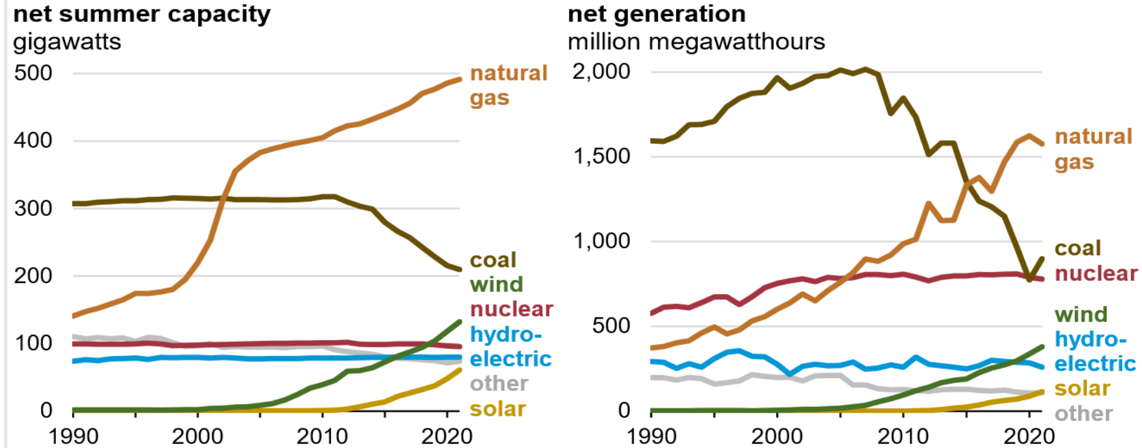
II. Trends and Conditions Affecting Coal-Fired Power Plants as of 2023

[16] "EPA proposes new rule to combat climate changing pollution from power plants (Timelines)," Harvard Environmental & Energy Law Program ("HEELP"), https://eelp.law.harvard.edu/2023/05/epa-proposes-new-rules-to-combat-climate-changing-pollution-from-power-plants/.

A. Background and Overview

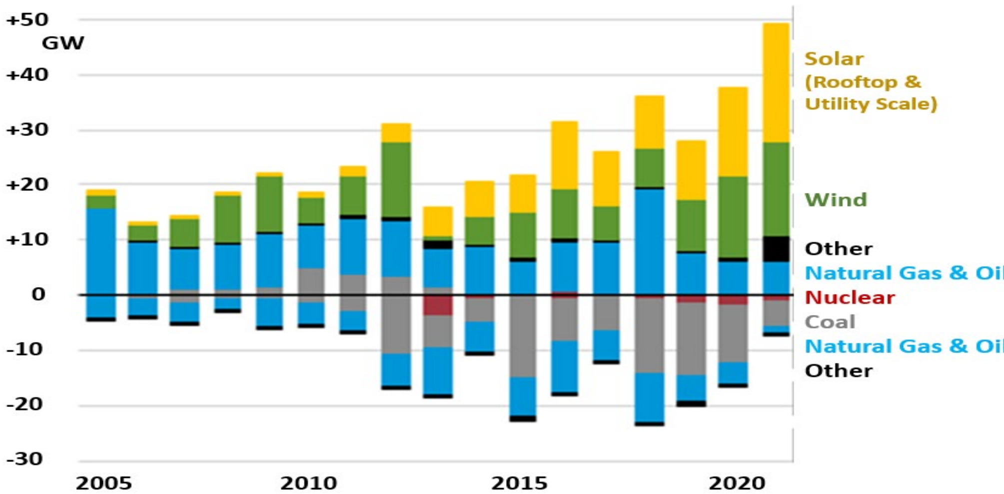
Over the past decade, U.S. coal-fired generating capacity and output have steadily declined. Power produced by coal declined by over half from its peak in the late 2000s. (Figure 1.) While total coal plant capacity remained relatively stable between 1990 and 2010 (left side of Figure 1), the combination of few coal-unit additions (with the last coal-fired power plant coming online in 2013) and continued retirements of older and less efficient units led to loss of a third of the nation's coal-generating capacity since around 2010. (Figure 2.)

Figure 1 –
Annual U.S. Electric Generating Capacity (GW) and Output (million MWh) by Fuel (1990-2021)



EIA, "Wind was second-largest source of U.S. electricity generation on March 29," *Today in Energy*, April 14, 2022, https://www.eia.gov/todayinenergy/detail.php?id=52038

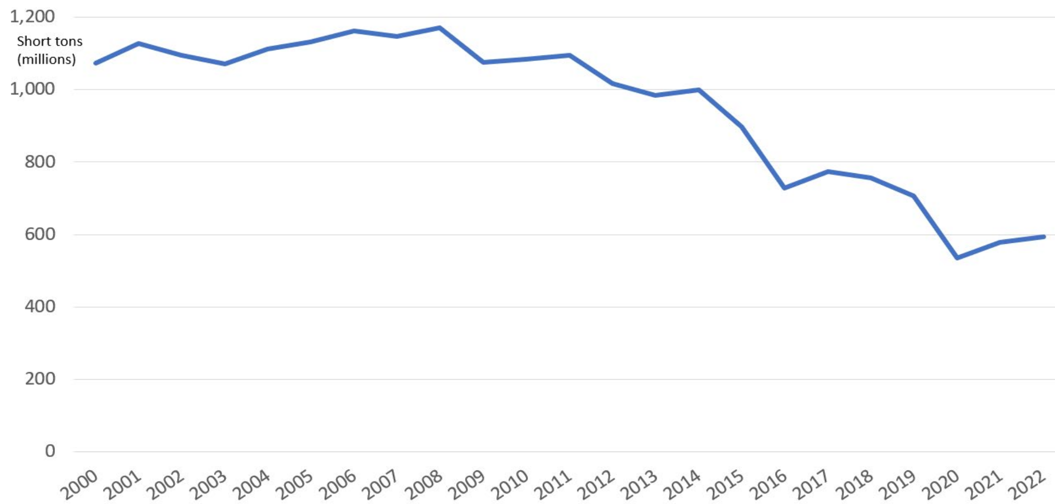
Figure 2 – Capacity Additions and Retirements by Fuel (GW) (2005-2021)



EIA, Outlook Narrative, *Annual Energy Outlook 2023*, https://www.eia.gov/outlooks/aeo/narrative/electricity/sub-topic-04.php

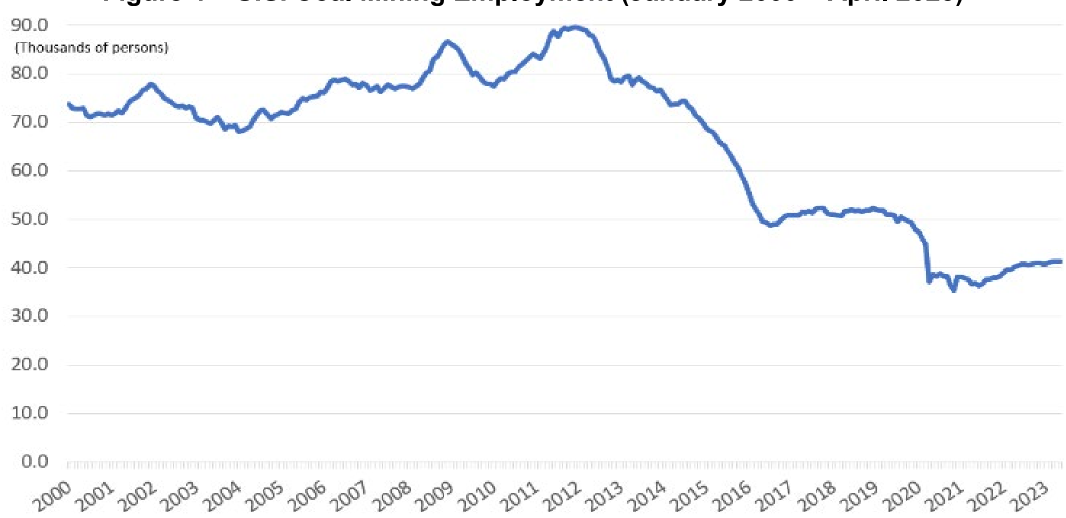
Largely as a consequence of such changes in the nation's power system and because most domestically mined coal serves the U.S. power market, American coal production (Figure 3) and coal-mining employment (Figure 4) also declined over the past decade.

Figure 3 – U.S. Coal Production (2000 – 2022)



EIA, Annual coal production data, https://www.eia.gov/coal/annual/.

Figure 4 – U.S. Coal Mining Employment (January 2000 – April 2023)



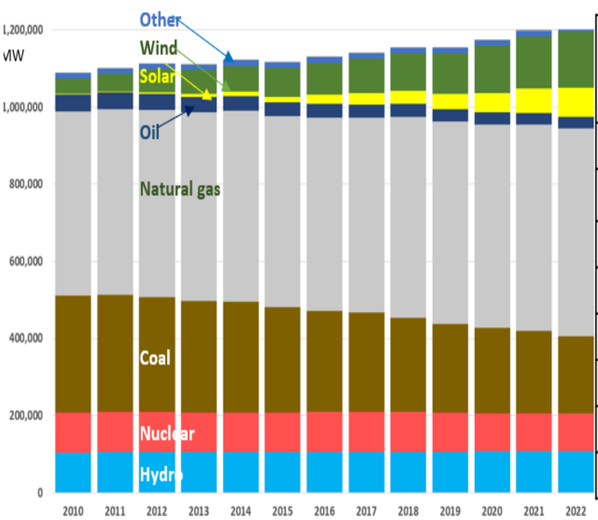
Federal Reserve Bank of St. Louis, https://fred.stlouisfed.org/series/CEU1021210001

These changes have been underway for some time, as explained in two papers written by this author roughly a decade ago.[17] Those papers identified numerous factors (e.g., flat electricity demand, low natural gas prices resulting from shale gas production, pre-existing underutilized capacity at natural gas combined cycle units, deployment of energy efficiency and renewable generating resources, insufficient revenues in wholesale power markets) that put economic pressure on coal-fired power plants. Other influences (e.g., productivity improvements and shifts westward in the geographic location of increasing percentages of coal production, decreased demand for coal supply) also led to reductions in coal-mining employment.

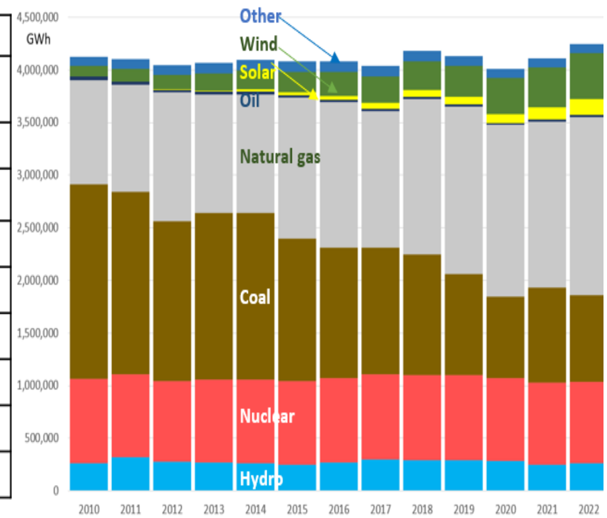
In the past decade, similar factors along with others have led to further declines in coal-fired capacity and generation. These factors include continued relatively low natural gas prices, power-system dispatch economics that shifted output away from the least efficient coal plants, improvements in cost and performance of other generating technologies (e.g., those using wind, solar, and natural gas), reductions in the cost of new wind, solar and gas-fired power projects leading to entry of such new capacity, state policies, corporate climate commitments, and more investment in grid-edge technologies like energy efficiency and rooftop solar.

Coal capacity and generation dropped more than any other power-system resource, with capacity declining by a third (left side of Figure 5) with generation declining by more than a half (right side of Figure 5). The key factors affecting such declines are discussed further below.

Figure 5 –
U.S. Electric Generating Capacity (MW) and Generation (GWh) by Fuel/Technology (2010 – 2022)



Technology	% Change (2010 to 2022)	
	Capacity (MW)	Generation (MWh)
Other	- 12%	- 3%
Wind	+ 255%	+ 359%
Solar	+ 5579%	+ 11,911%
Oil	- 33%	- 37%
Natural Gas	+ 13%	+ 71%
Coal	- 34%	- 55%
Nuclear	- 6%	- 4%
Hydro	+ 2%	+ 1%



EIA electricity generating capacity and generation data, https://www.eia.gov/electricity/data.php.

[17] Susan Tierney, "Why Coal Plants Retire: Power Market Fundamentals as of 2012," 2012, https://www.analysisgroup.com/uploadedfiles/content/news_and_events/news/2012_tierney_whycoalplantsretire.pdf; Susan Tierney, "The U.S. Coal Industry: Challenging Transitions in the 21st Century," 2016, https://www.analysisgroup.com/Insights/publishing/the-u-s--coal-industry--challenging-transitions-in-the-21st-century/.

B. Drivers of Change Over the Past Decade: Power System Economics and Dispatch

Economic dispatch of existing generating resources – the long-standing principle of standard operations of existing resources on a power system – is the core factor that put pressure on the financial viability of coal plants over the last decade. All else equal, grid operators – whether in regions whose operations are administered by a Regional Transmission Organization ("RTO") or an Independent System Operator ("ISO"), or in parts of the country with utility-run power systems – dispatch power plants and other resources (e.g., storage, demand response) in economic merit order so as to meet demand most efficiently at any point in time. As demand increases up and down over the course of a day, the resources with higher operating costs are dispatched up or down.[18]

Over the past decade, the availability of increasing quantities of newly added generating resources with zero or low operating costs[19] (including from renewable and gas-fired units operating with relatively low real-time natural gas prices) pushed many coal plants farther up the dispatch order. With relatively flat demand,[20] this led to lower utilization rates (also known as capacity factors) for poorer-performing coal plants, which in turn resulted in lower revenues for such coal plants in wholesale electricity markets. This had the effect of reducing the value proposition of spending money to continue to maintain them in operation (especially, for example, to meet new environmental requirements).

1. Natural Gas Prices

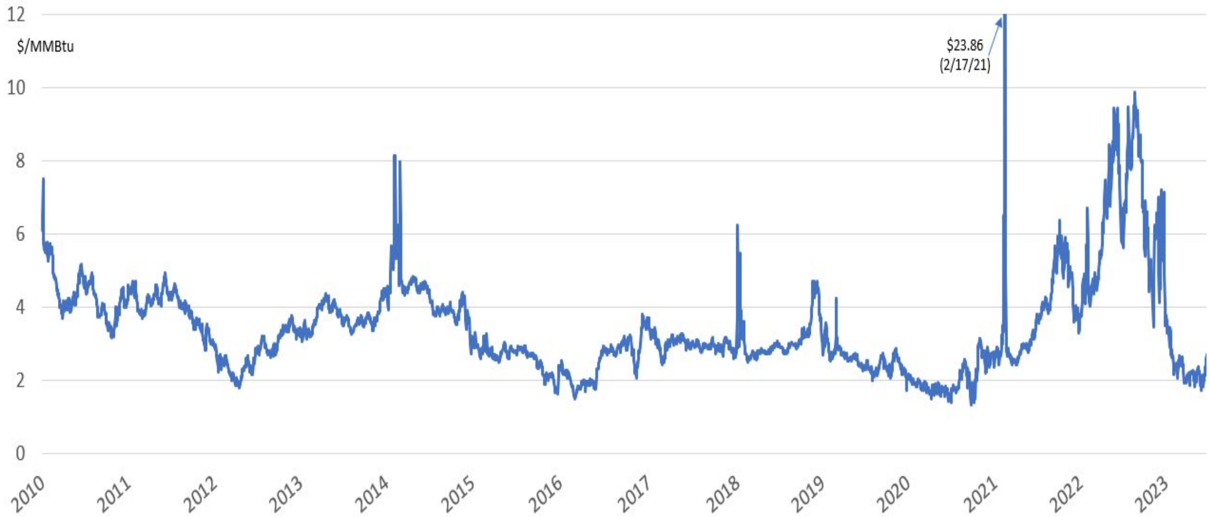
As shown in Figure 5, the dominant resource for producing power during the past decade was natural gas. Gas prices remained relatively low over most of the 2010s (Figure 6). Forward prices for gas-futures contracts (Figure 7) during this period also supported expectations in the power industry that gas-fired generation would continue to be strong, in competition with power produced at relatively inefficient coal power plants.

As shown in Figure 7, natural gas futures contract prices remained below $5.00 per MMBtu (and often well below that level) for much of the period since 2010 (and except for the fly-up in global gas prices and supply shifts in 2022 in the wake of Russian's invasion of Ukraine, with those gas futures prices having declined since then). In many parts of the country, electricity prices correlate with natural gas prices. As such, gas futures prices inform power project developers' and owners' decisions about the future profitability of their plants (e.g., given revenues in wholesale power markets). Such gas futures prices also inform decisions about whether to spend money to keep a power plant in operations given expectations about whether it is likely to be dispatched enough to be make such expenditures worthwhile. (*See* further discussion below of wholesale power prices, the dispatch of coal versus gas plants, and "spread spreads" and "dark spreads".)

---

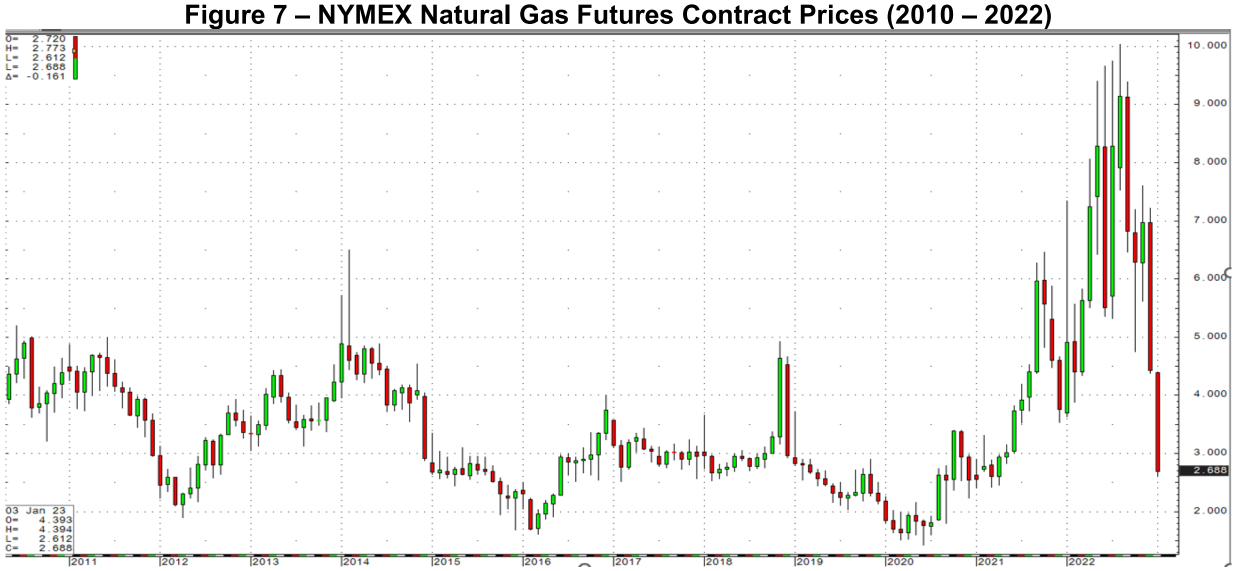
[18] Operational reliability considerations sometimes require a grid operator to dispatch plants out of economic order, in order to ensure that all parts of the system can meet load (demand) requirements even when the capacity of transmission lines is so fully used that they cannot deliver more economical but electrically distant power to consumers in a particular location and when therefore relatively expensive-to-operate nearby power plants need to be dispatched there.
[19] *See*: Figure 1 (left side), Figure 2 and Figure 5 (left side).
[20] *See*: Figure 5 (right side, top line of the chart), and further discussion below.

Figure 6 –
Natural Gas Prices – Henry Hub (Daily, $/MMBtu) (January 2010 – July 2023)



EIA, Henry Hub Natural Gas Spot Price data, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

Figure 7 – NYMEX Natural Gas Futures Contract Prices (2010 – 2022)



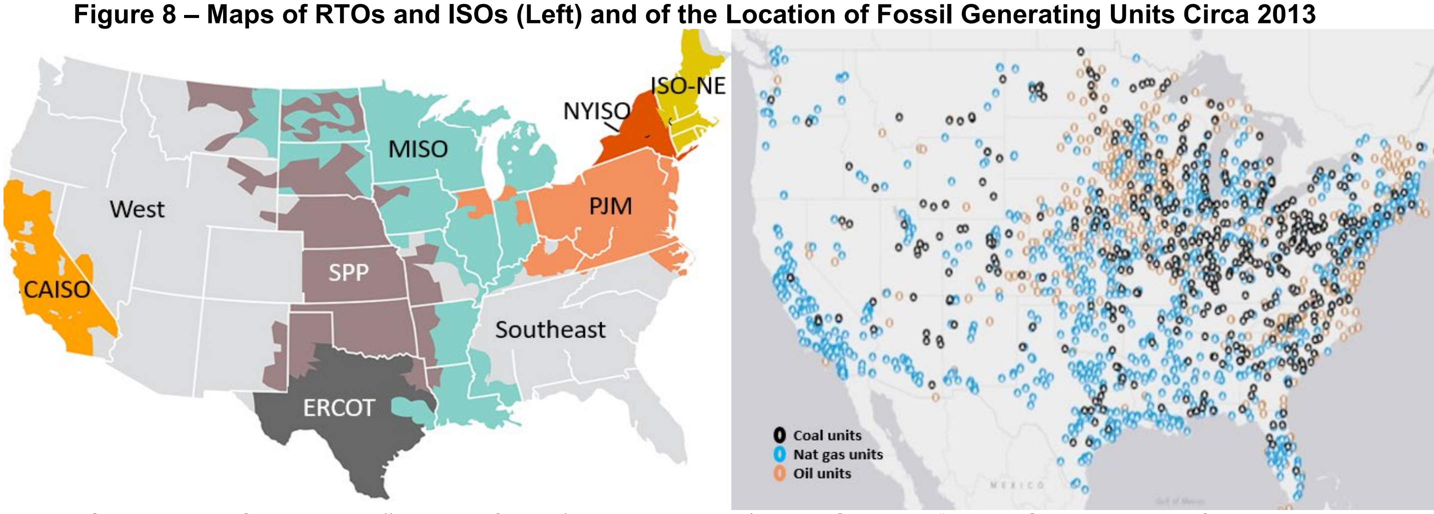
Hecht, "Natural Gas Futures – Not for the Faint of Heart," https://news.cqg.com/blogs/commentary/2023/02/us-natural-gas-futures-not-faint-heart.

2. Gas v. Coal Plant Economics and Dispatch

Fuel prices only tell part of the story, however. From a power generation dispatch point of view, the relative attractiveness of coal versus gas power plants depends not only on fuel prices but also the heat rate – the generating efficiency of a power plant, in terms of producing a MWh for a Btu of fuel) – of the different technologies and individual units that use those two fuels. Combined cycle gas turbine ("CCGT") plants tend to have lower heat rates than the average traditional steam-generating unit that burns coal (or even natural gas). Gas peaking units – typically technologies that are quick-start and more flexible for dispatch than many steam-generation coal plants – have relatively high heat rates and tend to be dispatched relatively infrequently (e.g., less than 15% of their potential to generate electricity). Together with relatively low gas prices, attractive heat rates mean that CCGT gas plants will be dispatched ahead of less efficient coal plants (as well as peaking units that use oil or natural gas).

In RTO/ISO markets – those regions of the country shown in a color other than gray in Figure 8 – power plants are dispatched by the grid operator based their "offer prices" to produce power. (Figure 8's right-hand map shows the location of fossil generating units in the various regions of the country and indicates the concentration of coal units as of 2013 in the MISO, PJM, SPP, and Southeast regions.)

Figure 8 – Maps of RTOs and ISOs (Left) and of the Location of Fossil Generating Units Circa 2013



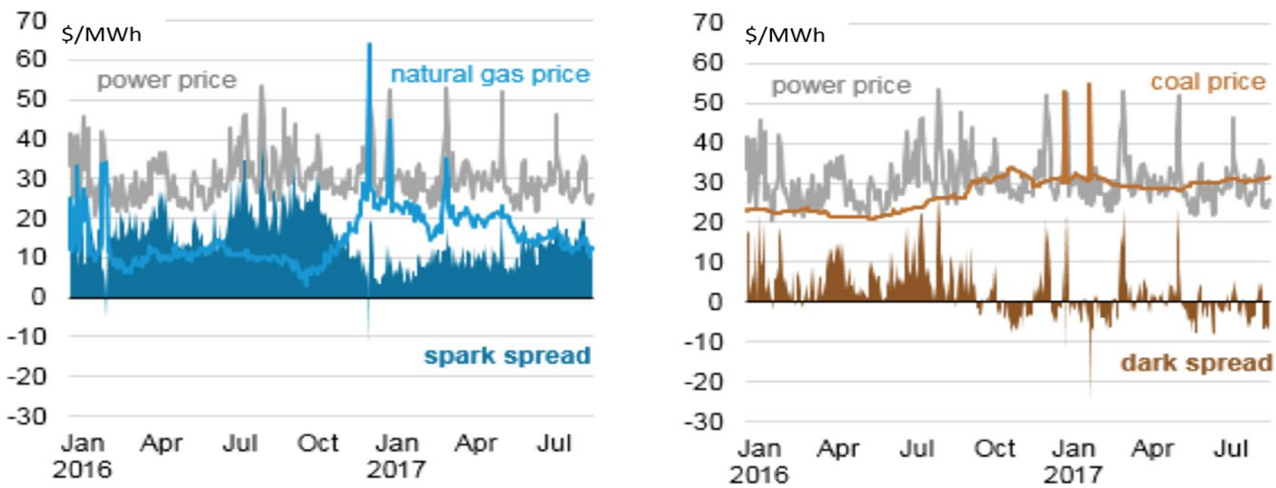
Sustainable FERC Project, https://sustainableferc.org/rto-backgrounders-2/; Joseph Stromberg, "Tour the Country's Energy Infrastructure Through A New Interactive Map," Smithsonian Magazine, August 10, 2013, https://tf-cmsv2-smithsonianmag-media.s3.amazonaws.com/legacy_blog/Head-map-big.jpg.

Offer prices reflect the costs associated with plant operations – including fuel costs, cost of pollution allowances, wear-and-tear costs, and other types of cost that vary with running the plant and producing power. Such offer prices allow the grid operator (including those in non-RTO regions shown in gray in Figure 8) to determine the dispatch order of individual supply sources.

In RTO/ISO regions, the clearing price for electricity is established based on the offer price of the most expensive generating unit last dispatched to meet demand at a given point in time. The clearing price is the price paid to generators dispatched to operate in that time period. The difference between a plant's own operating costs and the clearing price constitutes revenues that can be used to cover the plant's other costs that do not vary with output (e.g., debt, labor, profit, fixed maintenance costs). Units that have higher operating costs realize lower net revenues in this electric energy market. Industry analysts often refer to the term "spark spread" to characterize the difference in electric energy prices and the cost to operate a typical gas plant (given fuel price and heat rate), and the term "dark spread" to refer to the difference in electric energy prices and the cost to operate a typical coal plant (given its fuel price and heat rate).

To illustrate these spark spreads and dark spreads as they existed during the past decade (and why a prototypical coal plant faced more economic pressure than a gas plant), Figure 9 shows the daily wholesale electric energy prices in the western part of the PJM market during the January 2016-October 2017 period, as reported by the EIA. On the left is the spark spread for gas plants, shown in dark blue solid area on the chart, and with the other lines showing wholesale electricity price (in gray) and a gas-plant's fuel prices (in turquoise blue). On the right is the dark spread for coal plants, shown in the dark brown solid bars (with the same wholesale electricity price in gray and the coal plant's fuel costs shown in the brown line). Visually, one can see that during this period, a gas plant – as compared to a coal plant – realized higher spark spreads and thus higher revenues compared to costs.

Figure 9 – Daily PJM Western Hub wholesale electricity price and delivered fuel costs ($/MWh) (January 2016-July 2017)



EIA, based on price data from SNL Energy. EIA, "Spark and dark spreads indicate profitability of gas, coal power plants, Today in Energy, October 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=33312

These lower revenues put financial pressure on many existing coal plants over the course of the decade, leading to owners' decisions to retire many units (see further below). Lower output also led to overall lower capacity factors, with relatively poor prospects for improved operation if and when other resources (e.g., like more efficient gas-fired power plants, wind and solar capacity) entered the market and pushed coal-fired generation off the dispatch margin.

Figure 10 shows the declining capacity (in MW bars) and capacity factors (in the orange curve on each chart) for coal plants (at the top of the figure) and compares these metrics to the increasing capacity of units that burn natural gas (i.e., CCGTs in the middle chart of the figure and gas peaking units in the chart of the bottom of Figure 10).

Figure 10 – Trends in Capacity (MW) and Capacity Factors (%) of Coal Versus Gas Units: 2013-2022

EIA, Generation and Capacity Data

C. Drivers of Change Since 2012: State Climate and Electricity Policies and Corporate Commitments

Over the past decade, the commitments in state government energy and climate policies and in the climate/clean-power pledges of companies have supported electric-sector transitions with increasing quantities of renewable energy resources, among other things.

1. State Policies

Although many states have long had policies promoting increasing shares of electricity sourced from renewable energy resources,[21] during the past decade many states updated, increased or adopted new renewable energy standards ("RPS") (or clean energy standards ("CES"), or clean energy performance standards ("CEPS"). During 2021, for example, Delaware, Illinois, North Carolina, and Oregon increased the percentages of power that retail electricity suppliers must source from renewable energy, and Nebraska adopted its first clean energy standard (calling for 100% zero-carbon supply by 2050).[22]

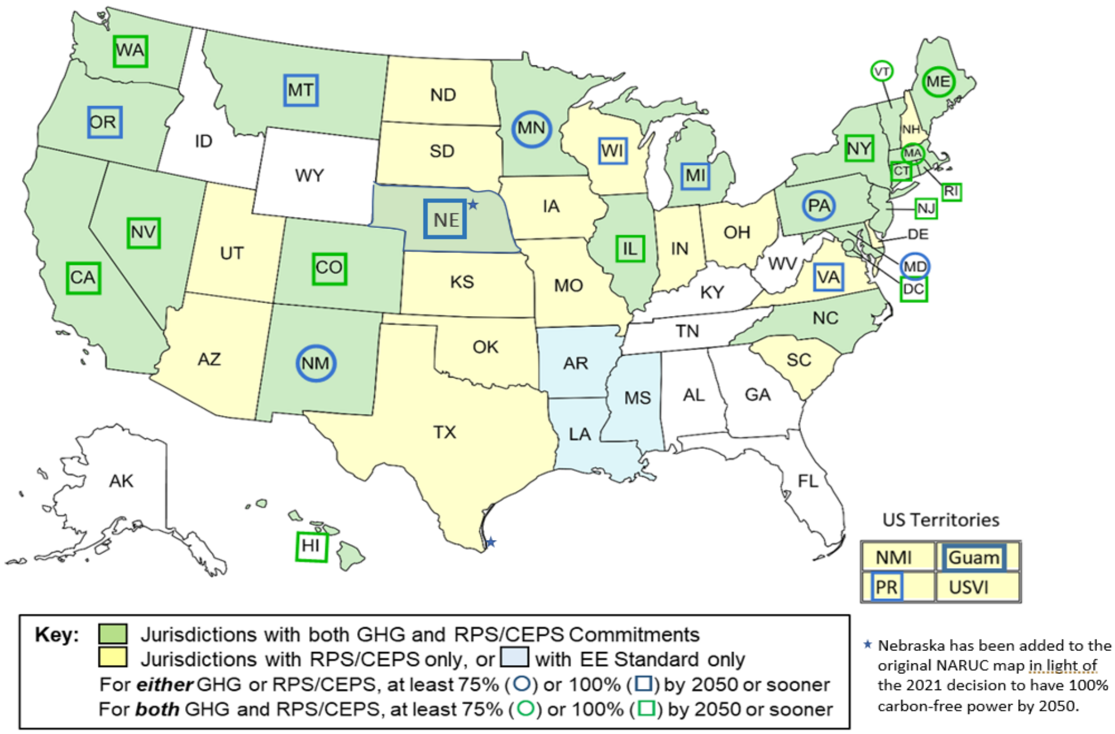
Additionally, the past decade witnessed more states' adoption of other policies that have helped to move renewable supplies into the market and keep zero-carbon generating resources in operation. Such policies (described below) have had the effect of helping to add and/or maintain facilities that are dispatched ahead of fossil generation when those renewable or zero-carbon power supplies are available, or reducing overall demand for grid-supplied electricity (which in combination with the prior factor also reduces potential output from fossil generation). For example:

- *State GHG emissions-reduction policies that require power-sector emissions reductions over time in the state*. Figure 11 shows the states and other American jurisdictions that have adopted both GHG-reduction and RPS/CEPS commitments (in green), or renewable/clean energy or energy-efficiency standards without GHG-reduction requirements (in yellow). Some of these jurisdictions' policies call for at least 75% or 100% outcomes (e.g., 100% renewables; 100% zero-carbon-emitting power supply) by 2050 or sooner, as indicated by a circle (for 75% outcomes) or a box (for 100% outcomes) around the abbreviated name of the state, territory or District.

---

[21] EIA, "Most states have Renewable Portfolio Standards," *Today in Energy*, February 3, 2012, https://www.eia.gov/todayinenergy/detail.php?id=4850.
[22] EIA, "Five states updated or adopted new clean energy standards," *Today in Energy*, February 1, 2022, https://www.eia.gov/todayinenergy/detail.php?id=51118#:~:text=In%20September%202021%2C%20Illinois%20increased,target%20of%2025%25%20by%202026..

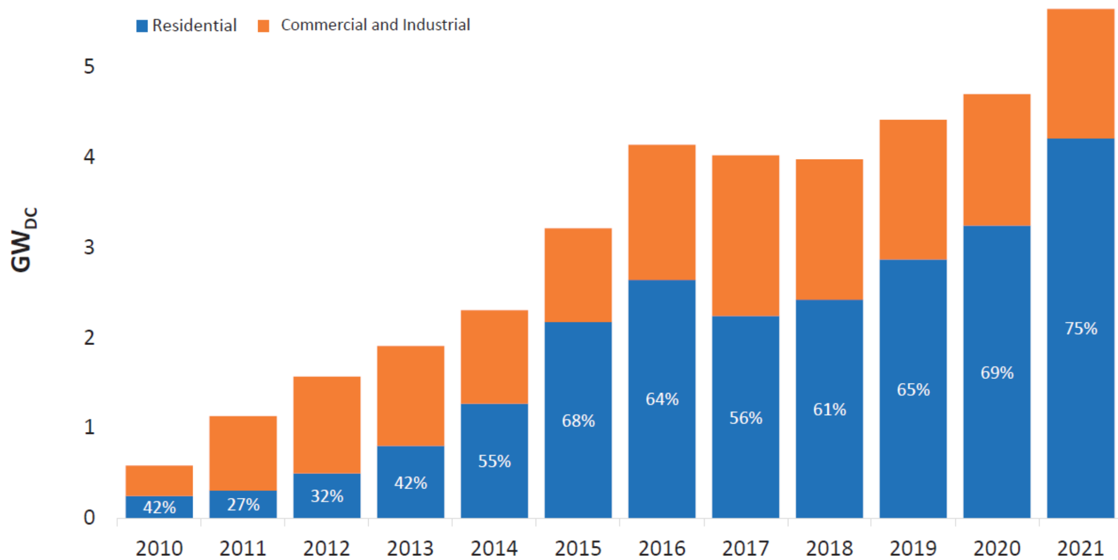
Figure 11 – States with "Clean Energy Policies" (As of 2021)



NARUC/NRRI, State Clean Energy Policy Tracker, https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/.

- *States' net energy meter policies*. Most states have in place net-metering policies (or some ratemaking variant to net metering) that allow for compensation to electricity consumers that have installed relatively small-scale generation facilities (rooftop solar PV, in particular) on their premises and export surplus power into the grid. By 2022, all but three states had implemented net metering policies (or a successor policies), which helped to encourage residential and commercial electricity consumers to add rooftop solar. (See Figure 12.) These solar installations not only supply-zero power to the grid whenever the sun is shining – in competition with fossil generation that could otherwise produce power in the areas – they also help consumers reduce their withdrawals from the grid and flatten overall grid-supplied electricity demand relative to what consumers would require in the absence of such rooftop solar PV.

Figure 12 –
Customer-Sited Solar PV Capacity Additions: GW Added by Year (2010-2021)



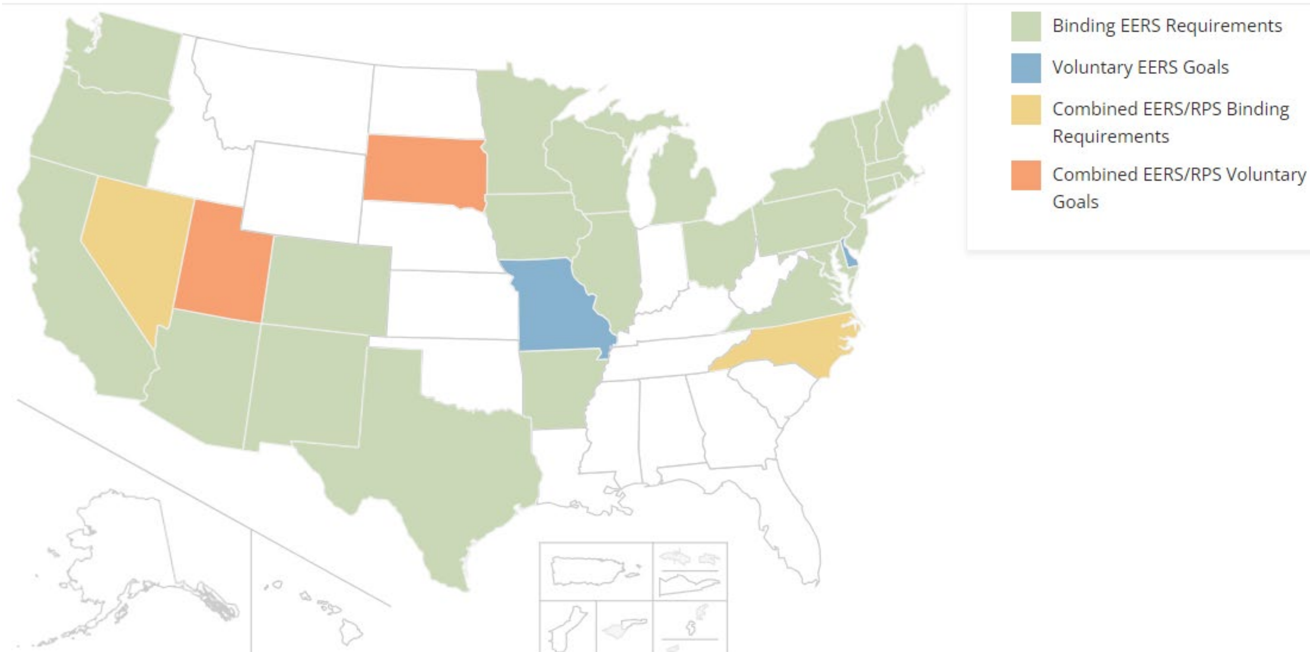
NASEM, "The Role of Net Metering in the U.S.," https://nap.nationalacademies.org/download/26704#.

- *State support for existing nuclear units.* At different points during the past decade, six states with currently operating nuclear plants implemented policies to provide financial support to maintain plants in operation that were otherwise at financial risk of shutting down. These states – California, Connecticut, Illinois, New Jersey, New York, and Ohio – used various strategies to accomplish this support in order to avoid loss of large generating units that produce power around the clock without GHG emissions. The 24 nuclear facilities with state policy/financial support add up to 21.34[23] GW of capacity (or over one fifth of all nuclear capacity in the country).

- *State requirements for deployment of energy efficiency measures.* More than half of the states have policies known as "energy efficiency resource standards" ("EERS"), which require electric utilities to realize energy savings as a percentage of the total amount of electricity sold in the state. Figure 13 shows states with such EERS policies[24], which ensure lower electricity demand relative to what would be expected without the EERS in place.

[23] Nuclear Energy Institute, Fact Sheet – U.S. Nuclear Plants, https://www.nei.org/resources/fact-sheets/u-s-nuclear-plants.
[24] Some of the states shown in this figure have EERS requirements for both their electricity and gas utilities. The following states' mandatory EERS requirements only apply to electricity sales: Hawaii; Illinois; Maryland; Nevada: New Mexico; North Carolina; Ohio; Pennsylvania; Texas; Utah; and Virginia. NCSL, Energy Efficiency Resource Standards, Updated September 2021, https://www.ncsl.org/energy/energy-efficiency-resource-standards-eers#toggleContent-27475.

Figure 13 –
States with Energy Efficiency Resource Standards (EERS)



National Conference of State Legislatures ("NCSL"), Energy Efficiency Resource Standards, Updated September 2021, https://www.ncsl.org/energy/energy-efficiency-resource-standards-eers#toggleContent-27475.

Again, the effect of these various state policies has continued to lead to less total demand for grid-supplied electricity and to reduce demand for power from fossil generation. These outcomes have been aided in the past decade by the existence of federal tax incentives and programs supporting consumers' installation of energy efficiency and solar projects, as well as developers' investment in renewable-power projects.[25] Some of these investments were made in years prior to the 2010s – such as happened in the roll-out of programs supported by the American Recovery and Reinvestment Act ("ARRA") of 2008 – and have long-lived effects on electricity demand and supply (e.g., more efficient buildings and appliances; installations of PV solar projects).

2. Corporate Climate and Electricity Commitments

Not only have legislatures and executive branch agencies of state governments taken steps in recent years to support investment in and deployment of more efficient, renewable and less-polluting electric technologies, but also private sector actors have done so as well. Two notable examples of corporate actions for clean power are the number of large companies that have procured long-term power supplies from renewable and other zero-

---

[25] For many years, federal laws have offered Production Tax Credits ("PTCs") and Investment Tax Credits ("ITCs") as incentives for investment in and supplies of power from renewable energy projects. The PTC was first authorized in the Energy Policy Act of 1992 and the ITC was first included in the Energy Policy Act of 2005. The two tax-incentive programs have been updated and re-authorized on multiple occasions since their initial enactment. See: "Renewable Energy Tax Credits," World Resources Institute, April 2008, https://files.wri.org/d8/s3fs-public/pdf/bottom_line_renewable_energy_tax_credits.pdf, and October 2010, https://files.wri.org/d8/s3fs-public/pdf/bottom_line_renewable_energy_tax_credits_10-2010.pdf; Molly Sherlock, "The Renewable Electricity Production Tax Credit: In Brief," Congressional Research Service, April 29, 2020, https://sgp.fas.org/crs/misc/R43453.pdf.

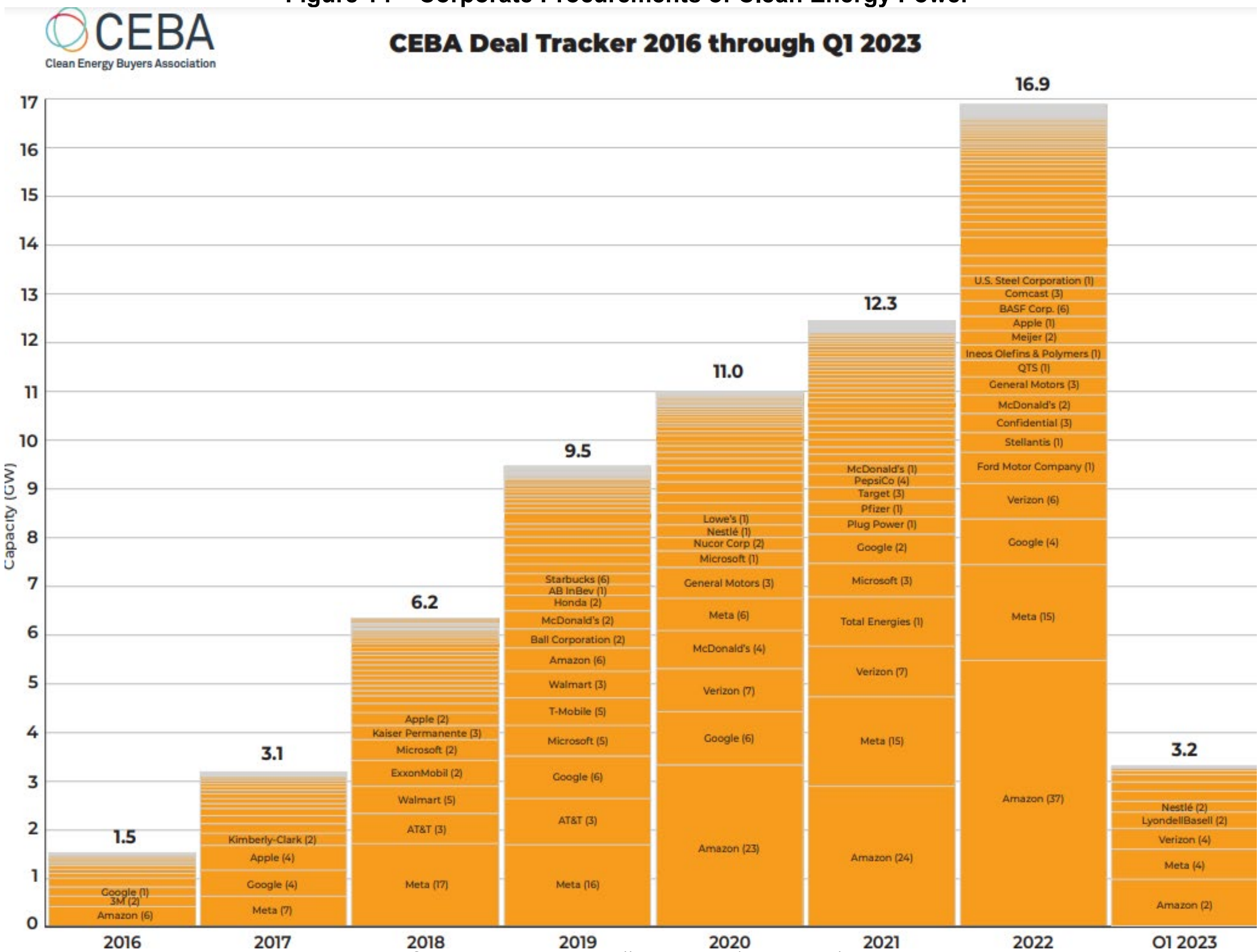
carbon facilities, and the extensive utility company commitments to reduce GHG emissions from their portfolio of generating resources.

According to the CEBA (the Clean Energy Buyers Association), corporations that are large electricity customers have entered into agreements totaling 68 GW of clean electricity capacity as of 2022,[26] with 16.9 GW signed up in 2022 alone and another 3.2 GW announced in the first quarter of 2023. As shown in Figure 14, the companies signing contracts for clean electricity (or for the renewable energy credits attached to output of wind and solar facilities) include major U.S. manufacturing, technology, communications, and other corporations such as Amazon, Apple, AT&T, Ford, General Motors, Google, McDonalds, Meta, Microsoft, Nucor, Pepsico, Pfizer, T-Mobile, U.S. Steel, Verizon, and Walmart. (Figure 14 shows publicly announced corporate clean energy procurements through power purchase agreements, green tariffs, tax equity investments, and project ownership in the U.S. from 2016 through March 31, 2023, and excludes onsite generation.)

Some of the projects qualify to meet states' RPS requirements, and thus may not signify net additions to the electric capacity and energy anticipated in those state policies; that said, the procurements reflect financial commitments that have helped to realize those policy objectives sooner than otherwise. Also, they reflect private-sector buyers' appetite for supplying their own electricity needs through renewable or other generation sources without GHG emissions.

[26] Total U.S. generating capacity as of the end of 2022 was 1,160.2 GW of electricity generating capacity, of which a small portion (approximately 39.5 GW) was small-scale solar PV capacity and the rest was utility-scale generating capacity. https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php#:~:text=At%20the%20end%20of%202022,solar%20photovoltaic%20electricity%2Dgeneration%20capacity.

Figure 14 – Corporate Procurements of Clean Energy Power



CEBA Deal Tracker, https://cebuyers.org/deal-tracker/.

Many electric utilities (and their holding company parents) have also made public commitments to reduce their GHG emissions, often in response to preferences of their customers, investors, and other public and private stakeholders.

Approximately four-fifths of all electricity customers in the U.S. are served by a utility that has commitments to reduce carbon emissions, either because the utility operates in a state with a mandatory carbon-reduction target or because the utility itself has made a voluntary climate commitment. According to SEPA (the Smart Electric Power Alliance) which tracks electric utility commitments, 42 utilities have adopted a voluntary 100% carbon-reduction target, and 497 individual utilities are "preparing to meet a state's 100% carbon-reduction target".[27,28] Figure 15 shows the geographic footprints of these utilities' service territories, with three figures showing compliance with 100% net-zero or net-neutral emissions (in yellow) or 100% renewable or clean power[29] (in blue) as of 2040 (top map), 2045 (middle map) or 2050 (bottom map). (Utilities with partial emissions-reduction commitments are shown in red.)

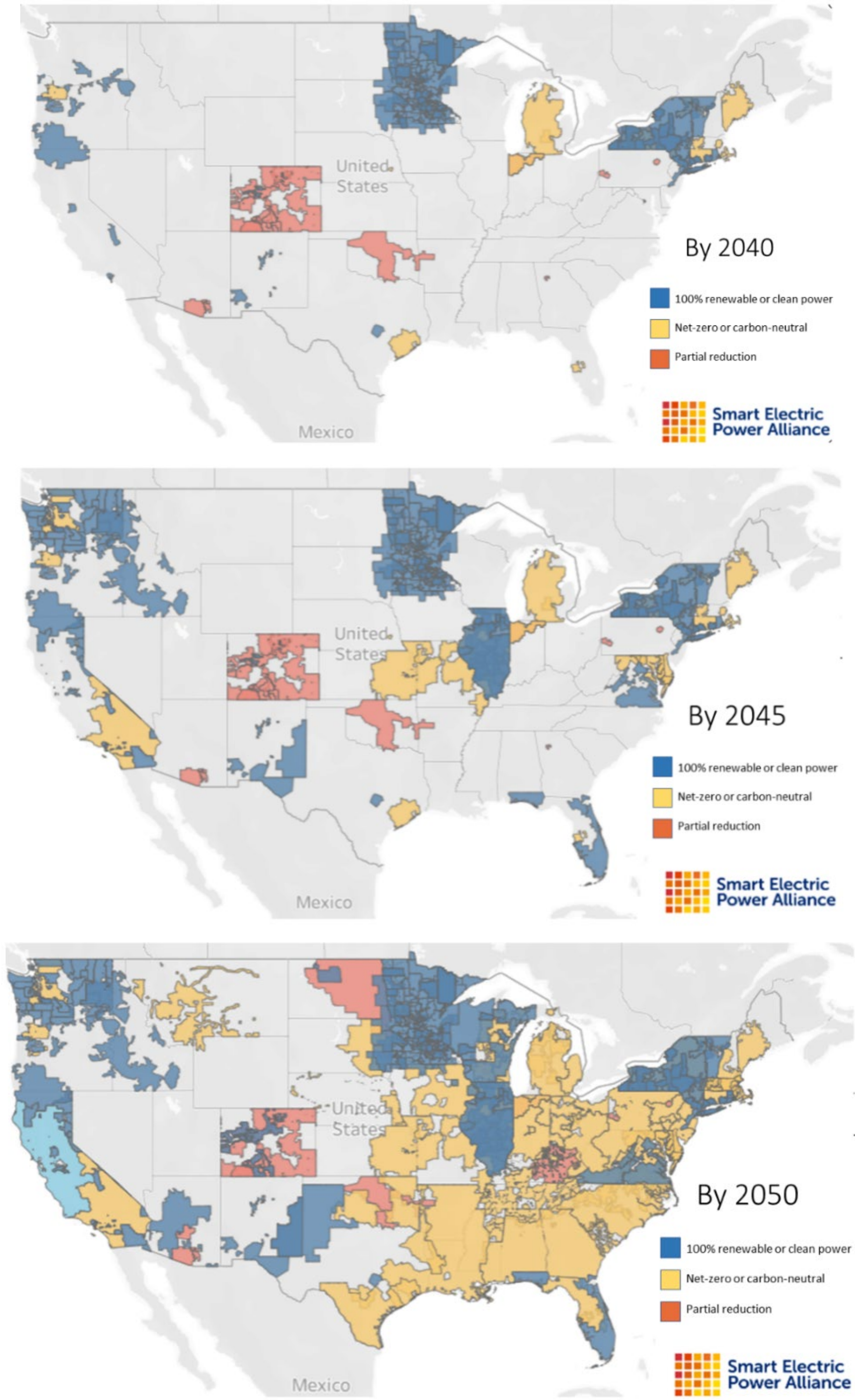
These utility commitments have been reported in investor-owned companies' financial disclosure statements filed with the Securities and Exchange Commission[30] and reflect financial decisions of boards of directors that making these commitments are consistent with the provision of safe, reliable and economic power supply for their customers and investors. Six electric companies (American Electric Power, DTE Energy, Duke Energy, Nextera, NRG Energy, and Southern Company) that own eight of the 10 biggest coal power plants in the U.S. have committed to be net zero emitters by 2050 or otherwise made significant reductions in GHG emissions.[31] Another statement indicating utility commitments is the statement of four major investor-owned utilities,[32] in conjunction with the leaders of major environmental advocacy and think tanks, that: "the U.S. must achieve net-zero greenhouse-gas emissions across the economy by 2050 to avoid the worst effects of climate change, and that rapid emissions reductions from the electricity sector is a cornerstone of economy-wide progress. By 2030, electricity sector emissions must be low enough for the U.S. to deliver on its economy-wide Nationally Determined Contributions" (which include as its cornerstone the target of reducing U.S. GHG emissions by 50-52% from 2005 levels by 2030[33]).

Some of these companies with net-zero commitments (shown in Figure 15) have also announced retirements of coal and natural gas power plants (discussed further below), with many of these retirements slated to occur well

[27] Also, "79% of U.S. customer accounts are served by an individual utility with a 100% carbon-reduction target or a utility owned by a parent company with a 100% carbon-reduction target…56 Individual utilities have adopted a voluntary carbon-reduction target." Smart Electric Power Alliance (SEPA), Utility Carbon-Reduction Tracker, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/ (with most recent dataset updated as of June 2023).
[28] SEPA indicates that the states with a mandatory and binding electricity requirement for 100% renewable or 100% clean power, or a binding net-zero requirement that applies to electric distribution utilities, by 2050 are: California; Connecticut; District of Columbia; Hawaii; Illinois; Maryland; Massachusetts; New Mexico; New York; Oregon; Puerto Rico; Rhode Island; Virginia; Washington; Wisconsin; SEPA states that related "state policy actions that are less enforceable, including executive orders and non-binding goals, are not displayed." https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.
[29] SEPA describes "clean power" as electricity generated by zero-emissions resources, which typically include renewables and nuclear facilities. https://sepapower.org/utility-transformation-challenge/frequently-asked-questions-faq/.
[30] See for example: Southern Company, 2023 Proxy Statement, https://s27.q4cdn.com/273397814/files/doc_financials/2023/ar/2023-Southern-Company-Proxy-Statement.pdf; Exelon Corporation, 2023 Proxy Statement, https://www.sec.gov/Archives/edgar/data/1109357/000130817923000188/exc_courtesy-pdf.pdf; Xcel Energy, 2022 Proxy Statement, https://www.sec.gov/Archives/edgar/data/72903/000007290322000019/combinedproxystatement.htm; Vistra Energy, 2022 Proxy Statement, https://filecache.investorroom.com/mr5ir_vistracorp_ir/284/VST%202022%20Proxy%20Statement.pdf.
[31] All of these companies besides AEP have net-zero targets by 2050; AEP's target is to be 80% below 2000 emissions levels by 2050. Michael Lustig, "ChartWatch: Owners of 8 of 10 largest US coal plants have net-zero targets," S&P Global Market Intelligence, August 24, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/chartwatch-owners-of-8-of-10-largest-us-coal-plants-have-net-zero-targets-59942473.
[32] Joint Statement of: Center for Climate and Energy Solutions, Center for the New Energy Economy at Colorado State University, Clean Air Task Force, DTE Energy, Edison International, Environmental Defense Fund, Public Service Company of New Mexico, The Nature Conservancy, World Resources Institute, Xcel Energy, "Accelerating Power Sector Decarbonization: It's time to Enact a Federal Clean Energy Tax Package in Budget Reconciliation," October 18, 2021, https://www.edf.org/sites/default/files/documents/Net%20Zero%20Roundtable%20-%20Tax%20Package%20Statement%20-%20Final%2010-18-2021.pdf.
[33] "United States' Nationally Determined Contribution: Reducing Greenhouse Gases in the United States: A 2030 Emissions Target," https://unfccc.int/sites/default/files/NDC/2022-06/United%20States%20NDC%20April%2021%202021%20Final.pdf.

before 2040 as these companies transition the carbon-intensity of their generating fleet on a trajectory to meet net zero commitments by mid-century.

Figure 15 –
Service Territories of Electric Utilities with Mandatory or Voluntary Renewable, Clean-Energy or Carbon Reduction Target – By Compliance Date (100% and Partial by 2040, 2045, 2050)



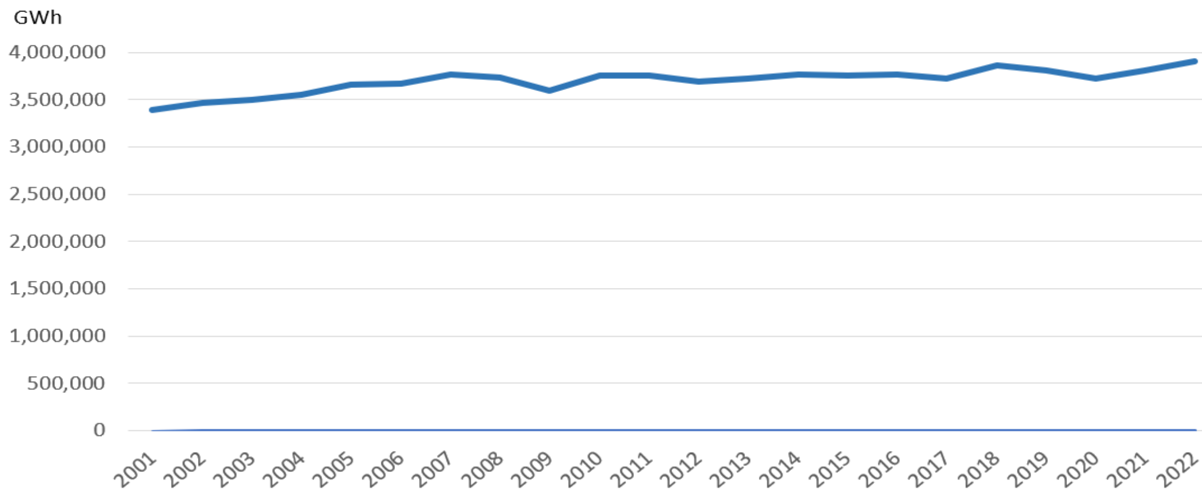
SEPA, Utility Carbon Reduction Tracker, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/

D. Drivers of Change Since 2012: Slow Demand Growth and Entry of New Electricity Supply Resources

1. Electricity Demand Conditions

Over the past decade and after many years of flat electricity demand in the U.S. (as shown in Figure 16 below), there have been recent but still only slight increases in overall demand for electricity. (Retail sales of electricity in 2020 hit a low point since 2010, due to the effects of the first year of the pandemic, but even this level of sales was only 1% lower than it was in 2010.) Between 2010 and 2022, electricity demand grew by a total of only 4 percent.

Figure 16 – U.S. Retail Sales of Electricity: 2001-2022



EIA, 826 data, https://www.eia.gov/electricity/data.php#sales

As discussed previously, this relatively flat demand growth results from increased efficiency of electricity use, not just from such things as EERS requirements, many states' requirements that utilities offer cost-effective energy-efficiency programs to customers, and decreased amounts of grid-supplied electricity as a result of installation of rooftop solar and its provision of on-site power supply to meet a customer's demand. It also results from increased appliance efficiency (in part from federal requirements for increased efficiency targets for many consumer appliances such as light bulbs).

One scholarly article ascribes a significant role to "the rapid emergency of LEDs and other energy-efficient lighting" in keeping electricity demand growth relatively low in the past decade: "Over 450 million LEDs have been installed to date in the United States, up from less than half a million in 2009. LEDs and other energy-efficient light now account for 80% of all U.S. lighting sales and according to a recent survey, 70% of American have purchased at least one LED bulb. It is no surprise that LEDs have been so popular. LED prices have fallen 94% since 2008, and a 60-watt equivalent LED lightbulb can now be purchased for about $2. LEDs use 85% less electricity than incandescents, so represent a significant savings in operating costs. LEDs are also much more durable than incandescents, are dimmable, and work in a wide range of indoor and outdoor settings."[34]

This relatively flat electricity demand has meant that with a growing share of supply from new renewables (including rooftop solar installations that satisfy much of the electricity demand of the households that install it), there has been less output at some of the least efficient generating resources (which use coal, oil, and natural gas). As described in the following section, significant amounts of generating capacity with very-low operating costs (i.e., wind and solar) and high power-production efficiency (e.g., natural gas combined cycle plants) were added over the past decade, thus exacerbating the output challenges for relatively inefficient coal plants with high operating and maintenance costs.

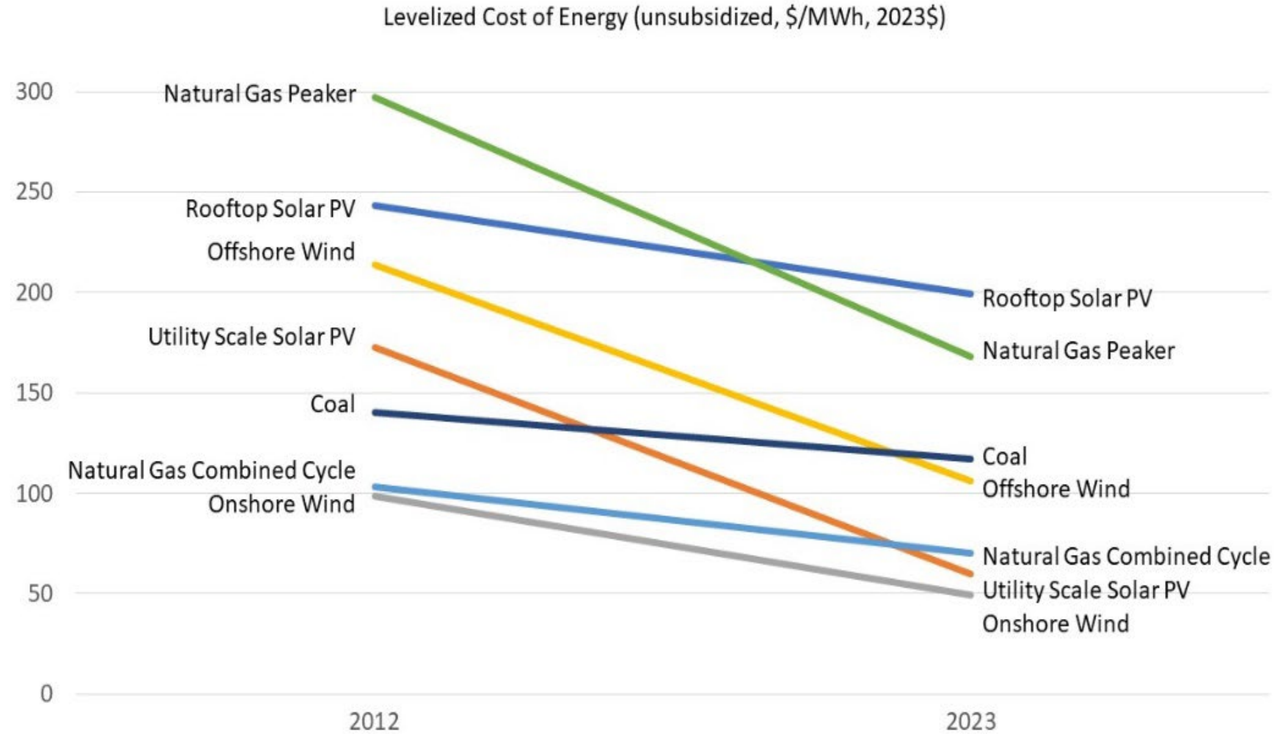
2. Diverse Competitive Supply Options

Over the course of the past decade, the declining costs and improving technical performance characteristics of new gas-fired, wind and solar projects led to significant additions of generating capacity from such technologies (as shown in Figure 2). Some of these capacity additions were to ensure the provision of adequate capacity, as companies considered whether to maintain and/or replace existing generating facilities. In some cases, electric utilities issued all-resource competitive procurements in which such suppliers of such technologies ended up as winning bidders. Some of the additions occurred to meet RPS requirements, boosted in part by the availability of federal tax incentives for investment in and production of power from renewable resources. The entry of new wind, solar, and natural gas facilities reflected electric companies' responses to economic and policy realities in place in the 2010s.

During the past few years, the going-forward levelized costs of new onshore wind and utility-scale solar dropped below those of gas-fired combined cycle projects – something that was not the case ten years ago. (Levelized cost is a measure of the cost to produce power over the life of a project, taking into consideration its capital costs, fixed and variable operating costs including fuel, and expected output, and serves as a measure for comparing costs of new technologies that have different sizes, operating characteristics, combinations of fixed and variable costs, and life spans.) Figure 17 shows the trends in levelized costs of various generating technologies. While there were cost reductions across the board for new fossil and renewable generating technologies, utility-scale solar showed relatively rapid reductions in levelized cost over the decade, as did offshore wind and rooftop solar. By 2022, new onshore wind and utility-scale solar technologies had lower costs than all other technologies.

[34] Lucas Davis, "Evidence of a decline in electricity use by U.S. households," Economics Bulletin, Volume 37, Issue 2. May 14, 2017, http://www.accessecon.com/Pubs/EB/2017/Volume37/EB-17-V37-I2-P96.pdf. Citations in the original have been omitted here.

Figure 17 – Levelized Cost of Electric Technologies: 2012, 2023 (2023$)

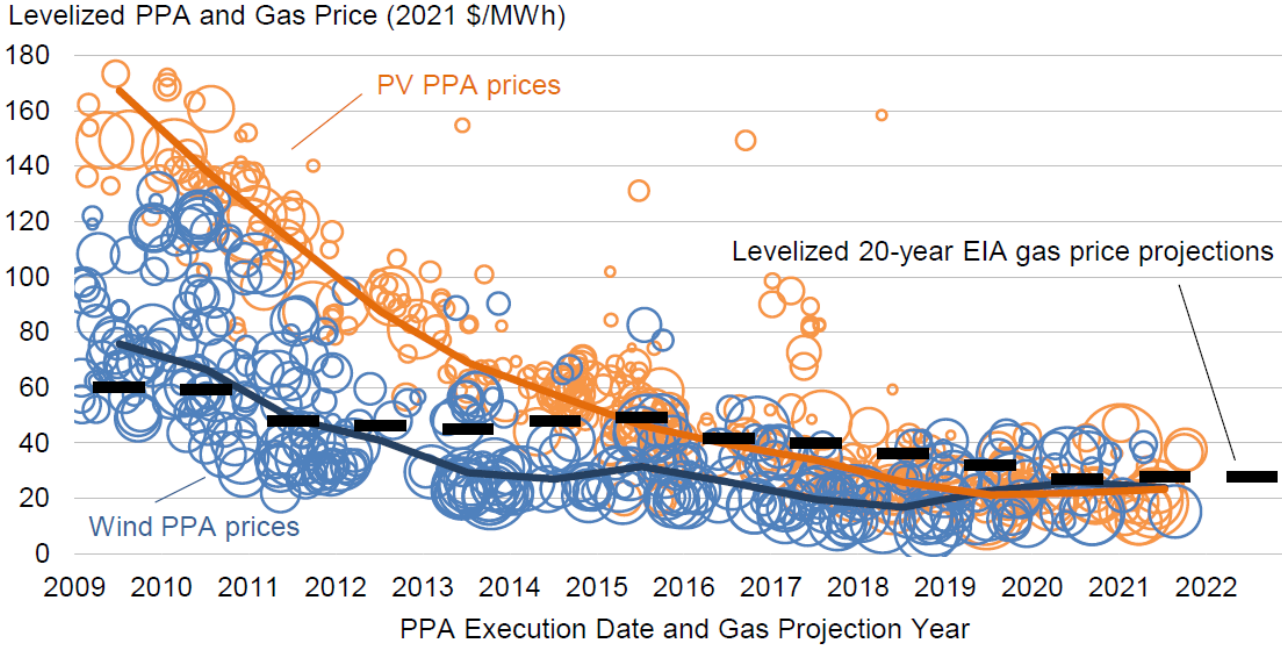


Sources: Lazard LCOE reports for 2012 and 2023 (with 2012 LCOEs reported in 2012 report adjusted for inflation, and with LCOEs reflecting the midpoint between the reported high and low estimates for each technology type).

These technology cost reductions also show up in the prices offered for winning power purchase agreements ("PPAs") over the decade. Figure 18 shows the price of power for PPAs for utility-scale solar and onshore wind projects, on a levelized basis over the life of the project and as of the first contract year of a signed PPA. As noted in the U.S. Department of Energy's "Land-Based Wind Market Report: 2022" from which Figure 18 is sourced, this chart shows that although "the gap between wind and solar PPA prices was quite wide a decade ago, that gap has narrowed considerably in recent years, as solar prices have fallen more rapidly than wind prices. The figure also shows that wind PPA prices – and, more recently, utility-scale solar PPA prices – have, in many cases, been competitive with the projected fuel costs of gas-fired combined cycle generators. Specifically, the black dash markers show the 20-year levelized fuel costs – converted from natural gas to power terms at an assumed heat rate of 7.5 million British Thermal Units (MMBtu) per MWh – from then current EIA projections of natural gas prices delivered to electricity generators. Supported by federal tax incentives, the average levelized wind and solar PPA prices within this contract sample have, for several years now, been below the projected levelized cost of burning natural gas in existing gas-fired combined cycle units."[35]

[35] Ryan Wyser et al., "Land-Based Wind Market Report, 2022 Edition," 2022, Department of Energy (hereafter "DOE 2022 Wind Market Report"), https://www.energy.gov/sites/default/files/2022-08/land_based_wind_market_report_2202.pdf.

Figure 18 – Natural Gas Prices and Power Purchase Agreement Prices for Land-Based Wind and Utility-Scale Solar Projects: 2009-2022 (2021 $/MWh)

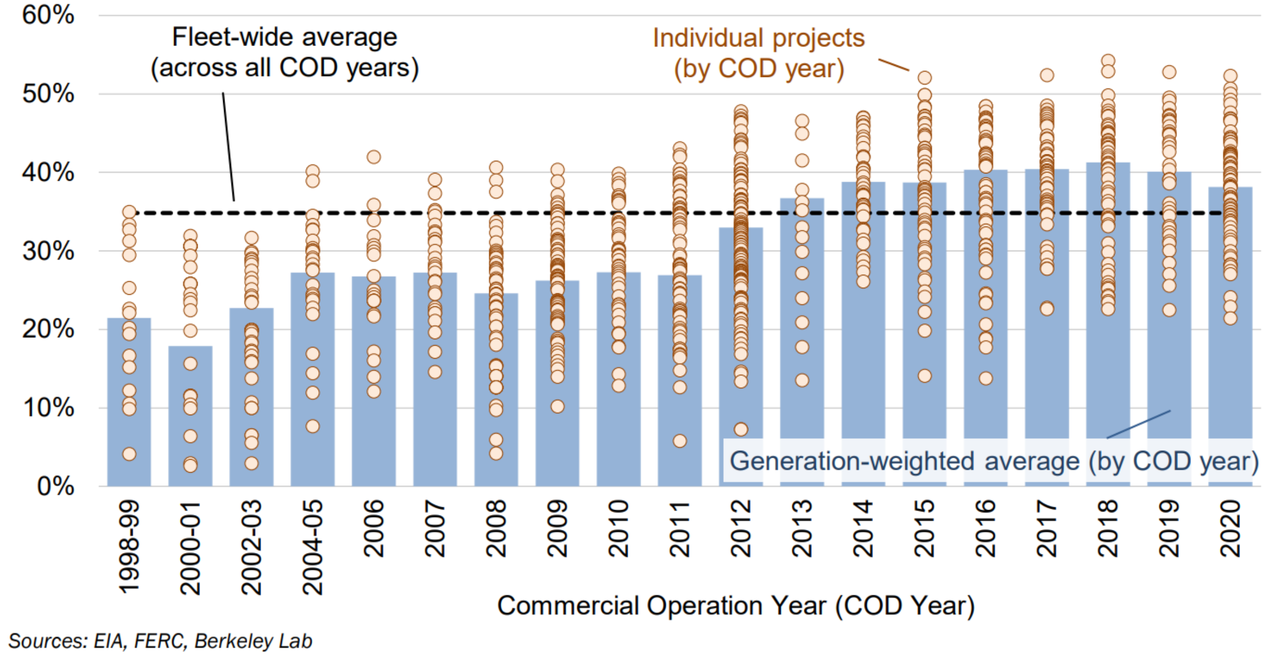


DOE 2022 Wind Market Report

Another metric for comparing power plants' performance is capacity factor – i.e., their actual output relative to their potential to produce power. For generating facilities (like fossil units) with fuel costs and other costs that vary with output, capacity factor is often a function of the relative cost of operating the plant, which the dispatch order of power plants takes into account (as explained above). But because wind and solar projects have no fuel costs, they generate electricity whenever the facilities are available to do so (that is, not out for maintenance or repair; and when the sun is shining or the wind is blowing) and they dispatch ahead of fossil units. In this regard, they are like nuclear facilities as well as run-of-the-river and other conventional hydroelectric facilities.

Wind projects' capacity factors depend on wind quality (e.g., the windiness of the location where the wind turbine is sited) as well as a project's equipment characteristics (e.g., tower height, turbine blade design, and other technical factors that enable a wind facility to produce power). The better the quality of wind and the turbine's performance characteristics, the more output one can expect from a project and from the capital cost invested in it. As shown in Figure 19, onshore wind projects' capacity factors showed significant improvement over the past decade, in part due to their improved operating efficiencies from better materials, higher towers and longer blades, which contributed to their better economic attractiveness over the past decade.

Figure 19 – Improvement in Onshore Wind Capacity Factors (Output) Over Time (Capacity Factor by Year of Project Installation)



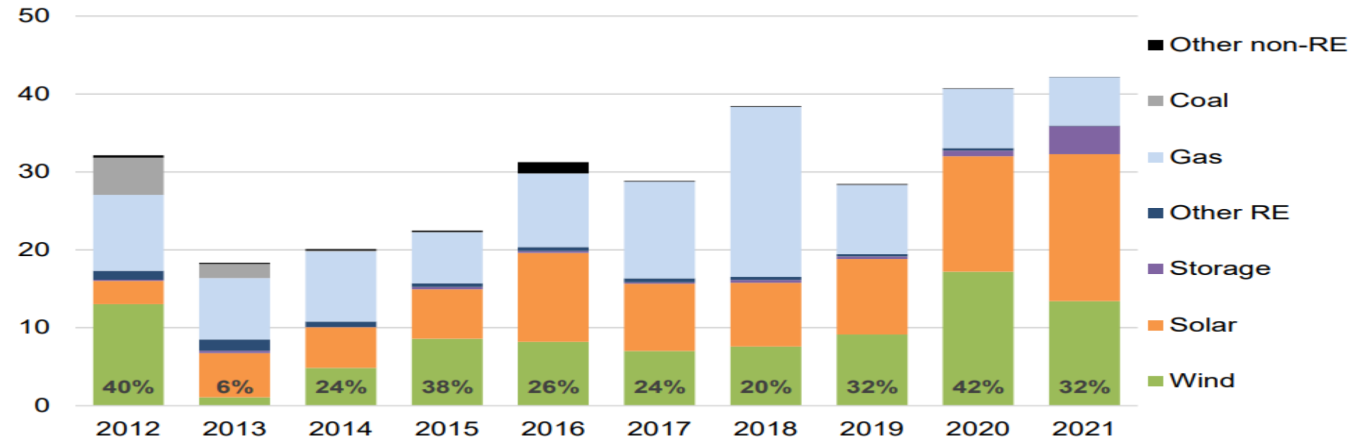
DOE 2022 Wind Market Report

Over the past decade, these improved economics for wind and solar projects, along with those of new gas-fired generating units, led to significant capacity additions of these technologies in all regions of the country. Figure 20 shows the amount of capacity additions from 2012-2022 by technology and/or fuel type.

Nearly 300 GW of new wind, utility-scale solar and natural gas generating capacity was added, with most capacity additions in the PJM region, ERCOT and the Southeast (as shown in Figures 21 and 22, which indicate capacity added by technology/fuel type and by region of the country).[36] Most of the wind capacity additions were in ERCOT, SPP and MISO. Utility-scale solar additions were in CAISO (California), the Southeast and the rest of the West, with most of the gas-fired capacity additions occurring in PJM, the Southeast and MISO (where significant amounts of coal plant capacity retirements was also occurring, as discussed further below). Since 2021, an additional 36 GW of coal-fired generating capacity also retired (or was scheduled to retire by the end of 2023).[37]

[36] The regional wholesale power markets shown in the figure are Regional Transmission Organizations ("RTOs"), Independent System Operators ("ISOs"). Parts of the West and Southeast do not participate in an RTO or ISO.
[37] EIA, Inventory of Generators for 2022 and 2023.

Figure 20 - Annual Capacity Additions by Technology (2012-2021)



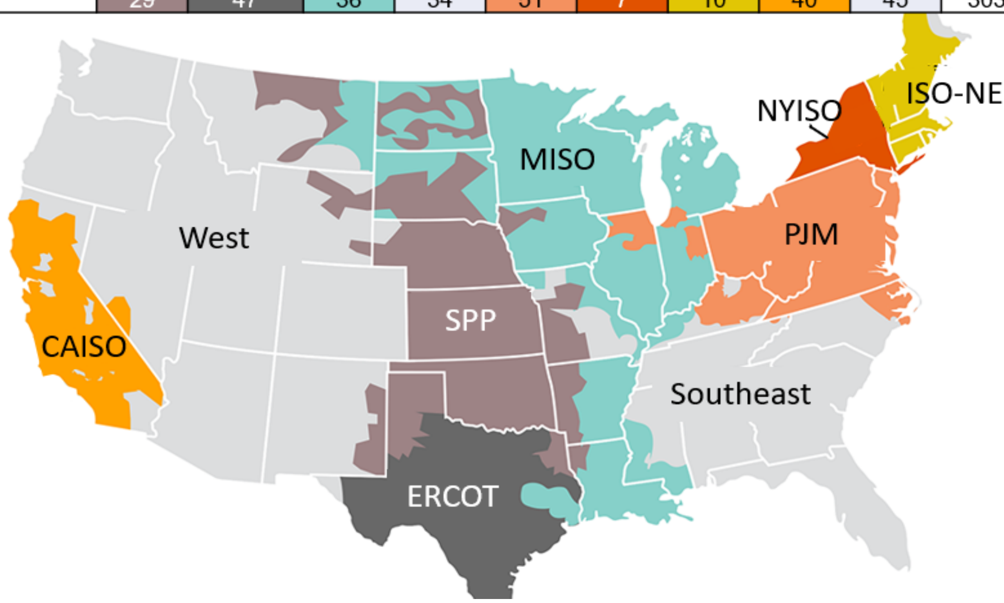
Sources: Hitachi, ACP, EIA, Berkeley Lab

DOE, Land-Based Wind Market Report: 2022 Edition, https://www.energy.gov/sites/default/files/2022-08/land_based_wind_market_report_2202.pdf

Figure 21 – Capacity Additions (2012-2021) and Electrical Regions of the U.S.

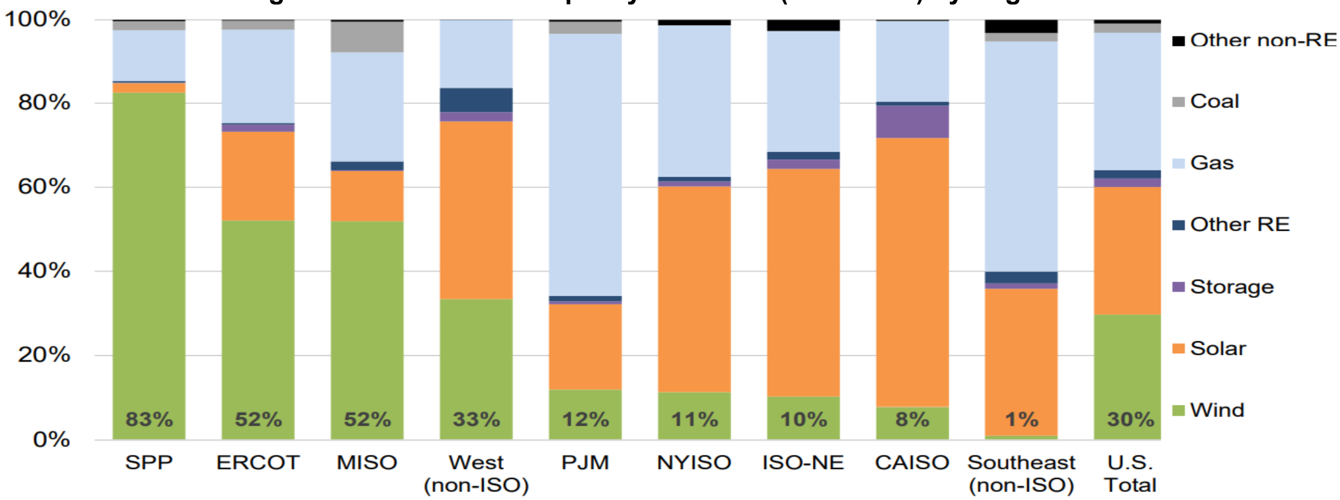
Total Capacity Additions by Region and by Technology (GW) 2012-2021

Capacity Type	SPP	ERCOT	MISO	West (non-RTO)	PJM	NYISO	ISO-NE	CAISO	Southeast (non-RTO)	U.S. Total
Gas	3.5	10.5	9.3	5.6	31.9	2.5	3.0	7.7	24.8	99.6
Solar	0.6	9.9	4.3	14.6	10.4	3.4	5.6	25.5	15.7	91.8
Wind	23.8	24.4	18.6	11.5	6.1	0.8	1.1	3.1	0.5	90.1
Storage	0.0	0.8	0.1	0.8	0.3	0.1	0.2	3.1	0.6	6.2
Other	0.8	1.3	3.7	2.0	2.4	0.2	0.5	0.5	3.6	15.2
Total	29	47	36	34	51	7	10	40	45	303



Capacity information by technology and region: DOE 2022 Wind Market Report.

Figure 22 – Percent of Capacity Additions (2012-2021) by Region



**U.S. Total also includes AK and HI, in addition to the regions listed*

Sources: Hitachi, ACP, EIA, Berkeley Lab

DOE 2022 Wind Market Report

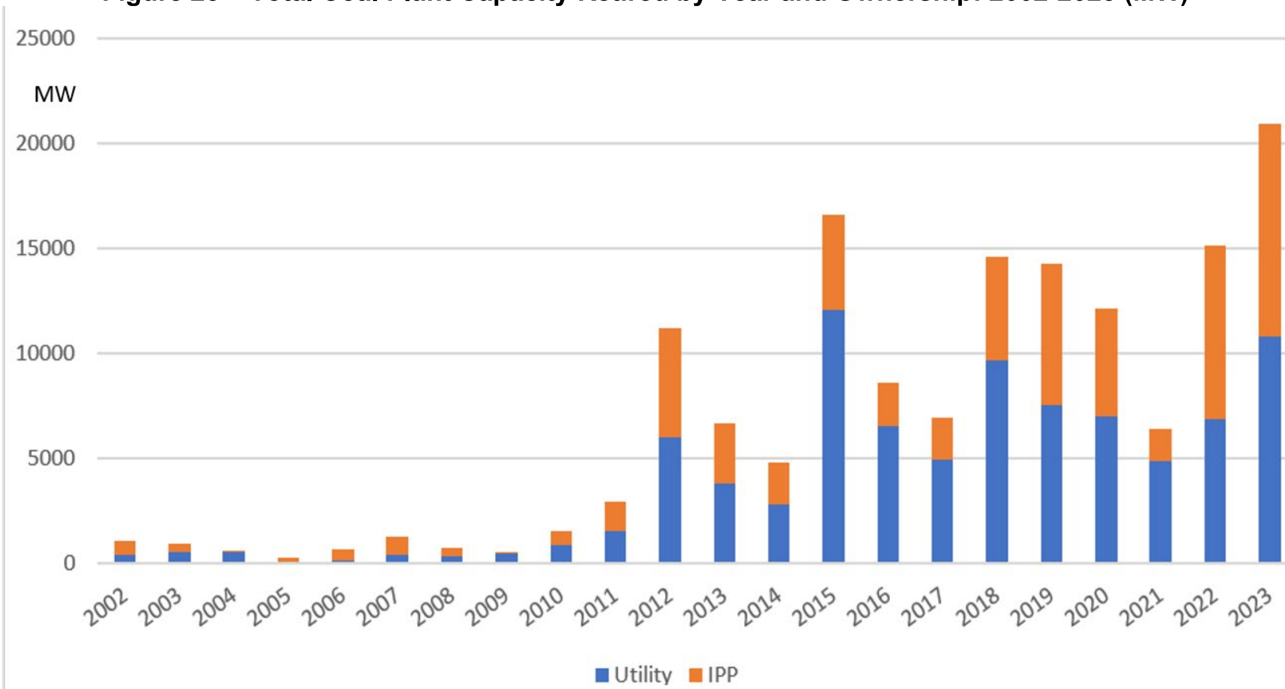
E. EPA Air Regulations During the 2010s: Lesser Driver of Change

The foregoing trends dominated investment, operating and retirement decisions of owners of power plants over the past decade. Many retirement decisions about older and relatively inefficient existing coal facilities were influenced to a lesser degree by federal environmental regulations as well. An indication of such is that more coal-fired generating capacity was retired in the years after major federal regulations affecting existing coal plants went into effect than in the years leading up to such implementation (as shown in Figure 23). Over the four-year period from 2012 through 2015, 278 coal units were retired, totaling 39 GW of coal plant capacity retired, with a spike in retirements occurring in 2015 (the year that regulations regulating mercury emissions from coal plants went into effect, as described below) and with those units tending to be smaller coal units whose low capacity factors and high costs did not support investment to comply with federal air regulations.[38] By contrast, in the years (2016-2023) since those regulations went into effect (as described further below), 312 more coal-fired generating units totaling an additional 90 GW will have retired (with a larger average size of 289 MW). These latter retirements thus were not specifically triggered by federal air pollution regulation related to mercury or GHG emissions. Most of this capacity was owned by utilities (as compared to merchant plants owned by non-utility companies), as shown in Figure 23).[39]

`[38] The average size of coal units retired in 2015 was 130 MW, compared to an average size of 280 MW for units that remained in operation beyond 2015. EIA, "Coal made up more than 80% of retired electricity generating capacity in 2015," Today in Energy, March 8, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25272#:~:text=The%20coal%20units%20that%20were,average%20age%20of%2038%20years.

[39] A merchant plant operates in the context of competitive markets, without having costs recovered in the rate base of a regulated utility.

Figure 23 – Total Coal Plant Capacity Retired by Year and Ownership: 2002-2023 (MW)



EIA, Inventory of Generators

For example, the final federal Mercury and Air Toxics Standard ("MATS") Rule was issued in February 2012 by the U.S. Environmental Protection Agency ("EPA"), generally giving coal-fired power plants four years to comply (i.e., by the Spring of 2016) and in special situations involving reliability considerations, allowing additional time on a case-by-case basis.[40] The MATS rule was appealed with the D.C. Circuit court upholding it in 2014 and, upon appeal, the U.S. Supreme Court in June 2015 sent it back for additional cost-benefit analysis.[41]

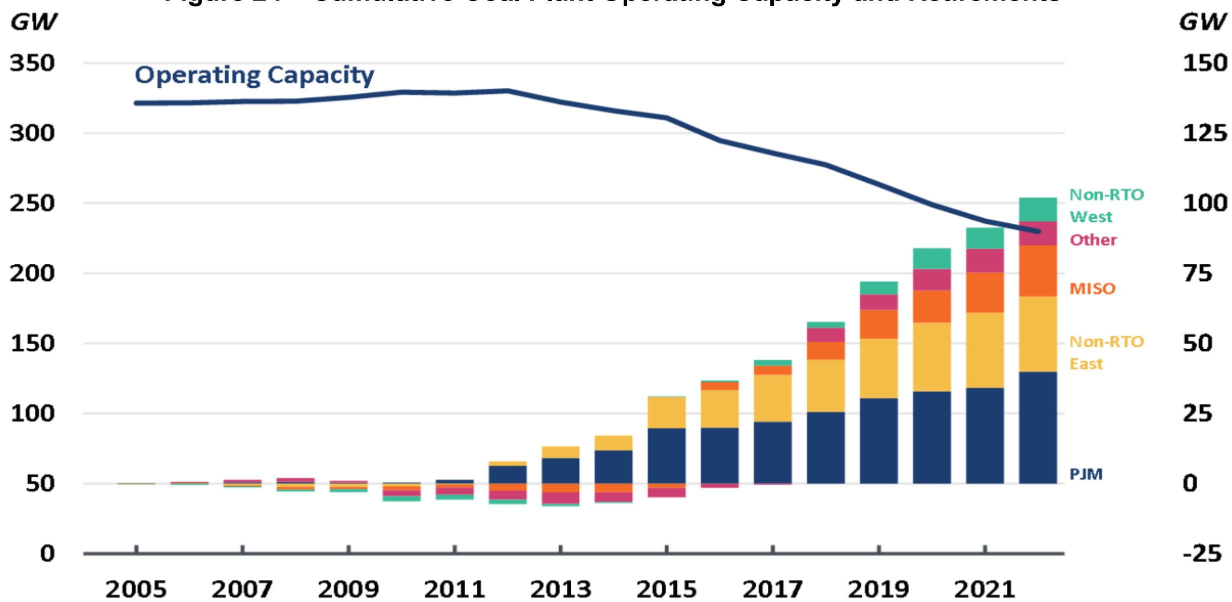
Additionally, although the EPA proposed (in 2014) and then adopted (in 2015) new rules to control GHG emissions from existing fossil units,[42] those rules were never implemented as a result of actions in federal court (including the Supreme Court) and a change in presidential administrations.[43]

[40] EPA's MATS Fact Sheet stated that: "Existing sources generally will have up to 4 years if they need it to comply with MATS. This includes the 3 years provided to all sources by the Clean Air Act. EPA's analysis continues to demonstrate that this will be sufficient time for most, if not all, sources to comply. Under the Clean Air Act, state permitting authorities can also grant an additional year as needed for technology installation. EPA expects this option to be broadly available. EPA is also providing a pathway for reliability critical units to obtain a schedule with up to an additional year to achieve compliance…In the unlikely event that there are other situations where sources cannot come into compliance on a timely basis, consistent with its longstanding historical practice under the Clean Air Act, the EPA will address individual noncompliance circumstances (if there are any) on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution." https://www.epa.gov/sites/default/files/2015-11/documents/20111221matssummaryfs.pdf. *See* also, https://www.govinfo.gov/content/pkg/FR-2012-02-16/pdf/2012-806.pdf, and https://eelp.law.harvard.edu/2017/09/mercury-and-air-toxics-standards/.
[41] HEELP, "Mercury and Air Toxics Standard" Regulatory Tracker, https://eelp.law.harvard.edu/2017/09/mercury-and-air-toxics-standards/.
[42] EPA, "Fact Sheet: Overview of the Clean Power Plan Final Rule," August 2015, https://archive.epa.gov/epa/cleanpowerplan/fact-sheet-overview-clean-power-plan.html.
[43] HEELP, "Regulating Greenhouse Gases from Existing Power Plants—the Clean Power Plan, the Affordable Clean Energy Rule, & 2023 Power Plant Rules," Regulatory Tracker, https://eelp.law.harvard.edu/2017/09/clean-power-plan-carbon-pollution-emission-guidelines/.

F. Coal Unit Capacity and Retirements in the Past Decade

The upshot of these various factors is that coal-fired generating capacity has declined by approximately one third over the past decade, from just above 303 GW at the start of 2013 to just below 196 GW by the end of 2023.[44] Figure 24 shows these cumulative retirements (through 2022), with most of them occurring in PJM, MISO and the non-RTO Southeast (as noted above).

Figure 24 – Cumulative Coal Plant Operating Capacity and Retirements

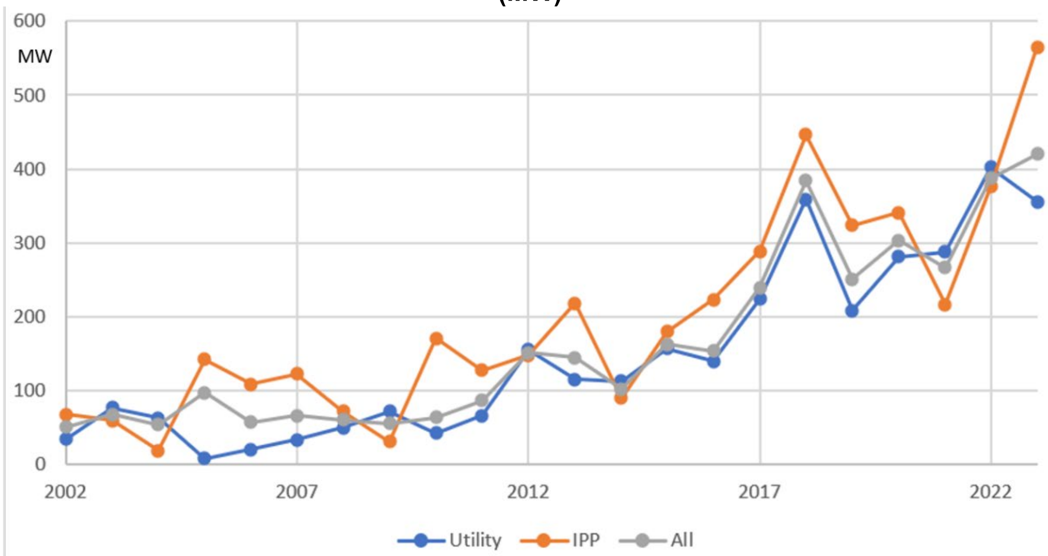


M. Celebi et al., (Brattle) "A Review of Coal-Fired Electricity Generation in the U.S.," Center for Applied Environmental Law & Policy, 2023, https://www.brattle.com/wp-content/uploads/2023/04/A-Review-of-Coal-Fired-Electricity-Generation-in-the-U.S..pdf.

Retirements this past 10 years involved 590 units, with retirements from 2012-2015 occurring at older and smaller units (averaging 52 years in operation and 121 MW in size) and those occurring after 2016 being larger (252 MW on average) and slightly younger (48 years old on average).[45] Figure 25 shows the trend in size of retiring units, for facilities owned by utilities and non-utility energy companies.

[44] EIA, Inventory of Generators (https://www.eia.gov/electricity/data/eia860/) and https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.
[45] EIA, Inventory of Generators.

Figure 25 – Average Size (MW) of Coal Power Plants at Retirement by Ownership Type: 2002-2023 (MW)



EIA, Inventory of Generators

G. Air Emissions From the Power Sector in the Past Decade

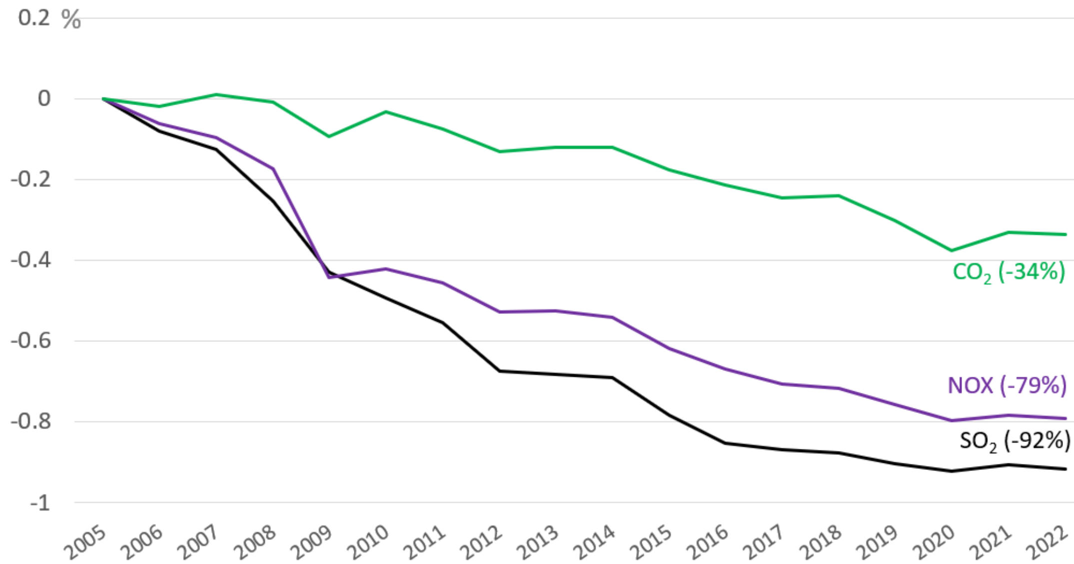
Emissions from power generation have declined significantly in recent years. Relative to 2005, which is the baseline year of high CO2 emissions in the U.S., Figure 26 shows the overall emissions reductions for sulfur dioxide (SO_2) (-92%), nitrogen oxides (NOx) (-79%), and carbon dioxide (CO_2) (-34%) from power plants since 2005.

As explained in a recent report from the Congressional Budget Office:

> The downward trend in emissions related to energy is largely attributable to a shift away from coal-fired generation to natural gas–fired generation in the electric power sector. About two-thirds of the decline in CO2 emissions in that sector has occurred because of the switch from coal to natural gas, and about one-third has come from increased generation from renewable sources, which do not release CO2. Since 2005, coal-fired generation has declined by 55 percent. About 70 percent of that decline has been offset by increases in natural gas–fired generation, which emits about half as much CO2 as coal. At the same time, wind and solar generation – which account for nearly all the growth of renewable generation – have together increased from less than 1 percent of all generation to nearly 13 percent. Changes in the average costs of producing power – from lower natural gas

prices and cost reductions in renewable generation – have been responsible for the changes in generation shares.[46]

Figure 26 – Emissions of SO2, NOX and CO2 from U.S. Power Plants: Percentage change since 2005



EPA data, https://www.epa.gov/power-sector/power-plant-emission-trends.

[46] Congressional Budget Office, "Emissions of Carbon Dioxide in the Electric Power Sector," December 2022, https://www.cbo.gov/system/files/2022-12/58419-co2-emissions-elec-power.pdf.

III. Looking Ahead: The Outlook for Coal-Fired Generation

A. Overview: Ongoing Influences of Market Fundamentals and Public Policy

The transition underway in the electric industry is likely to continue and potentially accelerate in upcoming years. All of the factors described above – state policies encouraging (and in many cases requiring) the increased use of renewable and zero-carbon electricity sources, utility commitments to decarbonize their electricity portfolios, other corporate commitments to procure clean energy supply, market fundamentals that also favor the addition of new renewables, low natural gas prices, and an aging coal fleet – are likely to continue to put pressure on coal-fired power plants to retire. As discussed further below, owners with coal plants have already announced a significant number of unit retirements to occur between now and the end of this decade.

One new set of powerful forces that will further push poorly performing coal plants out of the market is the relatively recent enactment of two major federal laws – the Infrastructure Investment and Jobs Act ("IIJA"), enacted at the end of 2021, and the Inflation Reduction Act ("IRA"), enacted in August 2022 and often called the most significant energy and climate investment statute ever enacted by Congress. The financial incentives and many other provisions of the IIJA and the IRA will continue and further hasten the transitions already described in the prior section of this report, and set the stage for the next round of regulations governing GHG emissions from existing fossil generating units that could go into effect in the upcoming decade.

This final section of this paper describes key relevant provisions of the IIJA and IRA, the announcements of coal plant retirements before and after these statutes were enacted, and the upcoming character of EPA's proposed GHG regulations for existing coal plants and other emitting power plants. Because other factors that contribute to transitions in the electric sector's portfolio of generating resources were described in Section II and will still be in place affecting changes in the upcoming decade(s), those factors are not repeated here.

B. Provisions of the Federal IIJA and IRA Relevant to the Electric Sector's Transition

Together, the IIJA and the IRA provide significant federal financial incentives and regulatory support for continued transformation of the electric grid.

Notably, in 2021 the IIJA signaled such support through a number of types of provisions:[47]

- By strengthening the ability of the Federal Energy Regulatory Commission to approve certain interstate transmission facilities and by creating a new Grid Deployment Authority at the Department of Energy to assist in building out the nation's high-voltage transmission grid – something that will help enable access to and development of significant high-quality renewable resources in regions remote from loads;
- By establishing a program to support financially distressed existing nuclear reactors;

[47] White House Guidebook to the Infrastructure Investment and Jobs https://www.whitehouse.gov/wp-content/uploads/2022/05/BUILDING-A-BETTER-AMERICA-V2.pdf.

- By providing funding for long-term research, development, innovation, and deployment of clean energy technologies (e.g., advanced storage technologies, advanced nuclear reactors, carbon capture technologies, and hydrogen facilities).

IIJA funding for "delivering clean power" totaled $21.3 billion, with another $21.5 billion for "clean energy demonstrations"[48] Much of the benefit of the IIJA's clean-energy provisions will accrue to clean-energy transitions a decade from now, but the provisions anticipate the potential for zero-emitting technologies to provide reliable supplies of power.

Nearer-term investments will flow from the provisions of the 2022 IRA, which included financial incentives for investment in renewable and zero-emitting technologies, grid modernization and resilience, storage systems, and energy efficient electricity-using technologies in buildings and transportation.[49] Estimates of direct federal funding from the IRA include:

- Programs with known amounts of direct funding (e.g., $27 billion for the EPA's Greenhouse Gas Reduction Fund; $3.6 billion for the Department of Energy's loan guarantee program);
- Open-ended financing for multi-year programs involving new and continued tax incentives for renewable and other clean-energy investments and power production, estimated to amount to financial incentives worth $270 billion (U.S. Treasury Department estimate[50]) to $394 billion (McKinsey estimate[51]).
- Reinforced EPA's authority to regulate GHG emissions from electricity generation as pollutants under the Clean Air Act ("CAA"). The IRA's Low Emissions Electricity Program modifies the existing CAA and provides $87 million in new resources to EPA itself to implement and ensure GHG emissions reductions under existing authorities and the Low Emissions Electricity Program.[52]

Also, the provisions of the IIJA and the IRA will leverage private-sector funding. A recent analysis by Goldman Sachs Research[53] estimates that the IRA "will provide an estimated $1.2 trillion of incentives by 2032" and "could encourage $11 trillion of total infrastructure investments by 2050…. The IRA includes incentives that make most clean tech – solar, wind, electric vehicles (EVs), and storage, as well as bio-energy, clean hydrogen, and carbon capture – profitable at large scale. Goldman Sachs Research estimates that the IRA's impact could encourage $11 trillion of total infrastructure investments by 2050. By 2032, our analysts estimate there will be $2.9 trillion of

[48] White House Guidebook to the Infrastructure Investment and Jobs https://www.whitehouse.gov/wp-content/uploads/2022/05/BUILDING-A-BETTER-AMERICA-V2.pdf.
[49] White House Guidebook on the Inflation Reduction Act, https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf.
[50] Note that the IRA's Clean Electricity Tax Production Credits will continue through the latter of 2032 or the year in which power sector CO_2 emissions are reduced by 75% relative to 2022 levels. https://home.treasury.gov/system/files/136/FactSheet-Implementing-IRA-Climate-CleanEnergy-TaxIncentives.pdf.
[51] https://www.mckinsey.com/industries/public-sector/our-insights/the-inflation-reduction-act-heres-whats-in-it.
[52] Greg Dotson and Dustin Maghamfar, "Clean Air Act Amendments of 2022: Clean Air, Climate Change, and the Inflation Reduction Act," Environmental Law Reporter, January 2023, https://www.eli.org/sites/default/files/files-pdf/53.10017.pdf. Notably, the new CAA amendments require that emissions reductions are additional to reductions already expected to occur from other policies.
[53] Goldman Sachs Research, "The US is poised for an energy revolution," April 17, 2023, https://www.goldmansachs.com/intelligence/pages/the-us-is-poised-for-an-energy-revolution.html

cumulative investment opportunity across sectors for the re-invention of U.S. energy system, or on average $290 billion annually."[54]

Several modeling studies have analyzed the implications of the combined financial incentives of the IIJA and IRA for electric system demand and capacity additions over the next decade. For example, a "multi-model" analysis authored by more than two dozen experts[55] and recently published in *Science*[56] examined the estimated range of impacts from the current policies including the IIJA and IRA. Regarding electric-sector impacts, the underlying models themselves analyzed the impacts of federal tax credits for clean electricity resources, energy storage and carbon capture and generation from existing nuclear plants. The models found that new zero-carbon resources and storage will enter the system between now and 2035 at rates either equal to or much more aggressive than in recent years and significant coal capacity will retire each year. (Figure 27 below, which is excerpted from the multi-model study, compares the projected average annual capacity additions and retirements to 2035.) The *Science* study observed that:

> Models consistently show that IRA leads to large increases in wind and solar deployment but with substantial variation in magnitudes. Across all models, growth rates from 2021 to 2035 range from 10 to 99 GW/year for solar and wind under IRA (58 GW/year average), which is more than twice the average of 27 GW/year without IRA and higher than the record 33 GW installed in 2021. There is wide variation in the expected increase in energy storage across models, 1 to 18 GW/year (7 GW/year average), compared with 0 to 8 GW/year in the reference.
>
> Results also exhibit reductions of unabated coal generation [i.e., without any carbon capture and storage (CCS)], ranging from 38 to 92% declines from 2021 levels by 2030 with IRA[57] … versus 3 to 60% without IRA. Five models show retrofits of some share of coal capacity with CCS, driven by the high value of tax credits for stored CO_2 (increasing from \$50/t-CO_2 historically to \$85/t-CO_2). Although all models suggest that gas-fired capacity will increase to provide firm capacity as load

[54] Further, Goldman Sachs Research analysts project that: "total U.S. power demand will increase 2.5 times by 2050 compared with 2021, which will require $6.6 trillion in renewable power investment. This includes the build-up of solar and wind (~$1.4 trillion each) and other renewable energy generation facilities (~$700 billion), the expansion, upgrade, and digitalization of power networks (~$2.3 trillion) and utility-scale energy storage facilities (~$800 billion). Renewable energy sources (excluding nuclear and hydro) are expected to grow by about 9% annually through 2050, representing 44% of total generation capacity by 2030 and 80% by 2050, according to GS Research. Our analysts anticipate that the early years of the new revolution will be driven mainly by electrification through the expansion of renewable power facilities, transmission, storage, and networks and building upgrades. Later, spending for clean hydrogen spending and carbon capture will accelerate. The report estimates that the average annual investment in decarbonization between this year and 2050 will be about $400 billion, representing about 1.3% of GDP, with the peak estimated at about $520 billion, or 1.7% of GDP, in the mid-2030s." https://www.goldmansachs.com/intelligence/pages/the-us-is-poised-for-an-energy-revolution.html.

[55] These experts are: John Bistine (Electric Power Research Institute ("EPRI")), Geoffrey Blanford (EPRI), Maxwell Brown (National Renewable Energy Laboratory ("NREL")), Dallas Burtraw (Resources for the Future ("RFF"), Maya Domeshek (RFF), Jamil Farbes (Evolved Energy Research ("EER")), Allen Fawcett (EPA), Anne Hamilton (NREL), Jesse Jenkins (Princeton University), Ryan Jones (EER), Ben King (Rhodium Group ("Rhodium"), Hannah Kolus (Rhodium), John Larsen (Rhodium), Amanda Levin (Natural Resources Defense Council ("NRDC")), Megan Mahajan (Energy Innovation ("EI")), Cara Marcy (EPA), Erin Mayfield (Dartmouth College), James McFarland (EPA), Haewon McJeon (Center for Global Sustainability, University of Maryland ("U Maryland")), Robbie Orvis (EI), Neha Patankar (Binghamton University), Kevin Rennert (RFF), Christopher Roney (EPRI), Nicholas Roy (RFF), Greg Schivley (Carbon Impact Consulting), Daniel Steinberg (NREL), Nadejda Victor (National Energy Technology Laboratory ("NETL")), Shelley Wenzel (EI), John Weyant (Stanford University), Ryan Wiser (Lawrence Berkeley National Laboratory), Mei Yuan (MIT Joint Program on the Science and Policy of Global Change), Alicia Zhao (U Maryland).

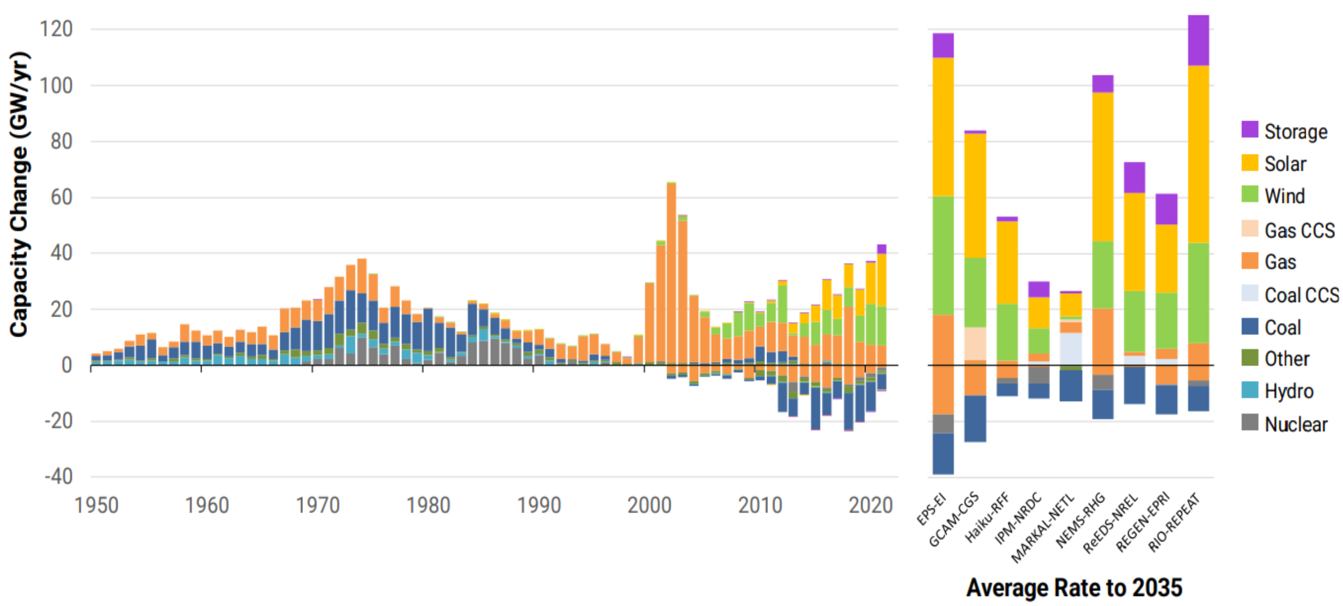
[56] John Bistine, et al., "Emissions and energy impacts of the Inflation Reduction Act: Economy-wide emissions drop 43 to 48% below 2005 levels by 2035 with accelerated clean energy deployment," *Science*, June 29, 2023 (hereafter "*Science* Study"), https://www.science.org/stoken/author-tokens/ST-1277/full.

[57] *Science* Study, with references to figures in the excerpted original text omitted.

grows and coal retires, most models also suggest that natural gas generation will decline under IRA relative to today's levels.

Overall, generation shares from low-emitting technologies – including renewables, nuclear, and CCS – in 2030 vary between 49 and 82% (68% average) across models with IRA, up from about 40% today and from 46 to 65% without IRA (54% average), an 11 to 33 p.p. [percentage point] increase. Power sector generation and emissions outcomes under IRA are more closely aligned by 2035 across models.

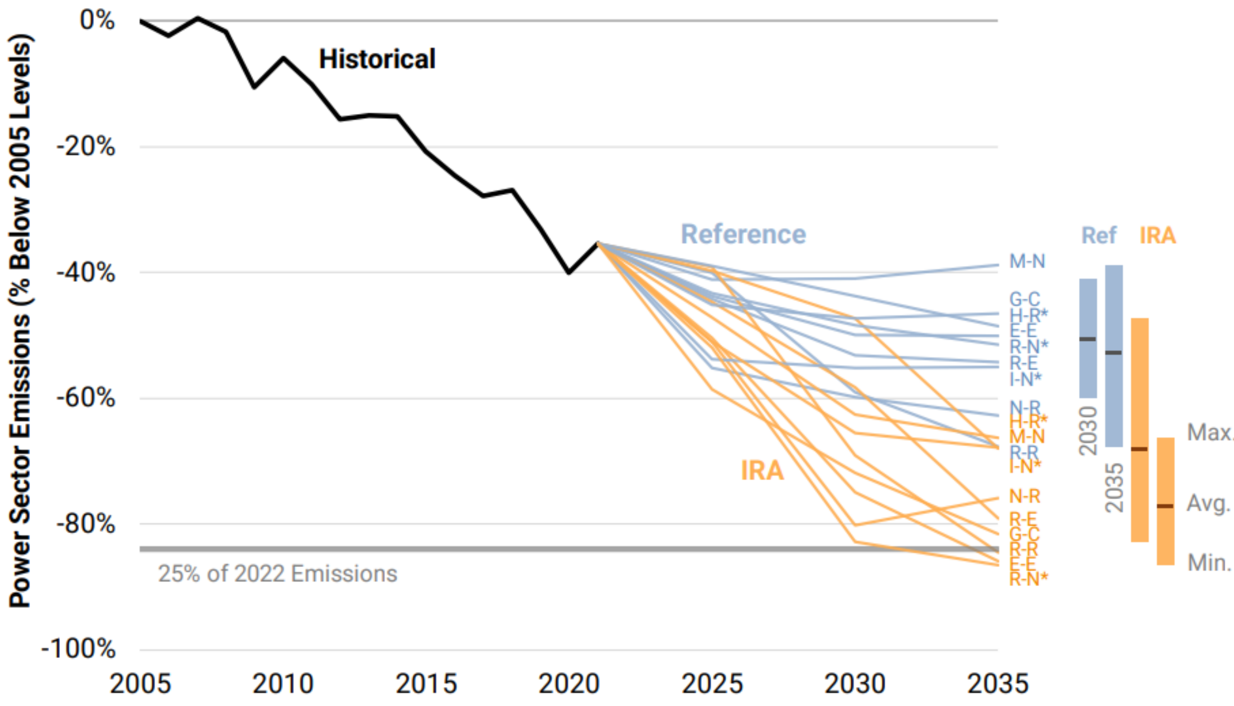
Figure 27: Capacity Additions and Retirements by Fuel (GW/yr): Actual (1950-2022) and Nine Studies' Estimates (2023-2035)



Science Study.

Figure 28 shows the range of these models' estimates of power-sector emissions, with all models indicating dramatic reductions in GHG emissions over the next decade relative to pre-IRA assumptions (shown in the Reference case in Figure 27 below, from the Science study). The *Science* study states:

Figure 28 – GHG Emissions from the U.S. Power Sector: Actual Historical (2005-2022) and Projected (2023-2035) Using Reference (Pre-IRA) and With IRA Forecasts from Nine Studies



Science Study.

C. Actual Announced Coal-Unit Retirements Before and After the IRA/IIJA

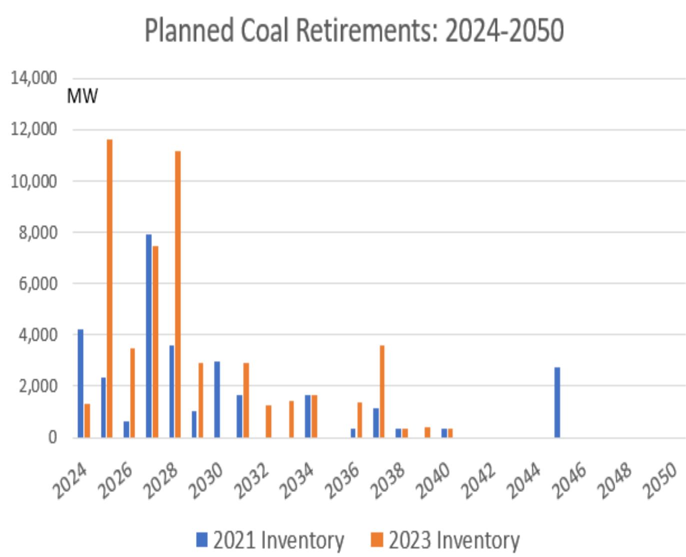
Another indication of the impact of these two new federal statutes can be seen in a comparison of planned retirements of coal plants from the period before enactment of the IIJA (e.g., January 2021) to the retirements currently planned for coal plant capacity (e.g., April 2023).

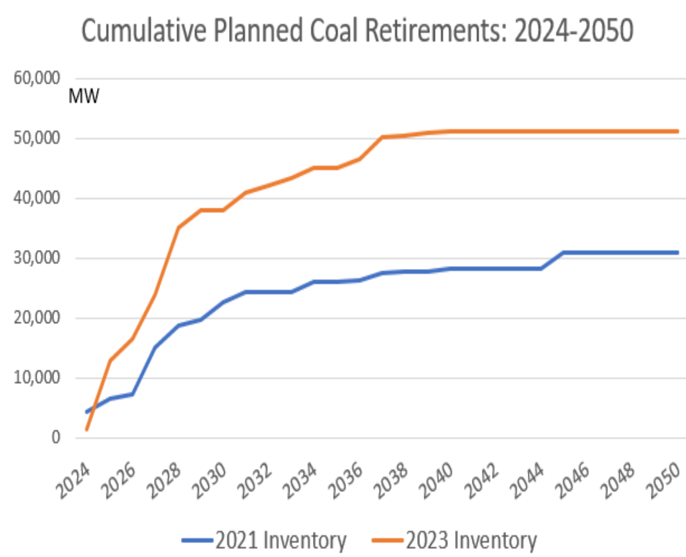
At the beginning of 2021, although there was new executive-branch leadership that was more supportive of decarbonizing the power sector, no one knew whether Congress would enact incentives or requirements affecting power-sector transitions, and if so, what the provisions of such policies would look like. By contrast, as of this writing, Congress has enacted both the IIJA and the IRA, and President Biden has taken steps for the U.S. to rejoin the Paris Agreement and made pledges that electric sector emissions would need to be low enough for the U.S. to deliver on its economy-wide Nationally Determined Contributions (reducing U.S. GHG emissions by 50-52% from 2005 levels by 2030).

Between the beginning of 2021 and the second quarter of 2023, owners of coal plants had more information that national policy supported reduction in power sector GHG emissions.

Figure 29 compares the electric industry's plans in early 2021 versus mid 2023 with respect to retirements of coal plants over the 2024-2050 period. The chart on the left of Figure 29 shows MWs of planned retirements of coal plant capacity in each year from 2024 onwards, with the blue bars indicating retirements anticipated as of early 2021 and the orange bars indicating planned retirements as of mid-2023. The chart on the right of Figure 29 shows cumulative planned retirements (in MW) for plans as of early 2021 (in blue) and as of mid-2023 (in orange). Cumulative planned retirements for the 2024-2050 period grew by 166% from January 2021, when the amount was 30.9 GW, to May 2023, when the amount was 51.2 GW. The coal-fired generating units with announced retirements through 2035 are shown in Figure 30 (with this map capturing most of the capacity planned for retirement indicated in Figure 29, which extends beyond 2035).

Figure 29 – Planned Retirements of Coal-Fired Generating Capacity (2024-2050) as of 1/2021 and 4/2023

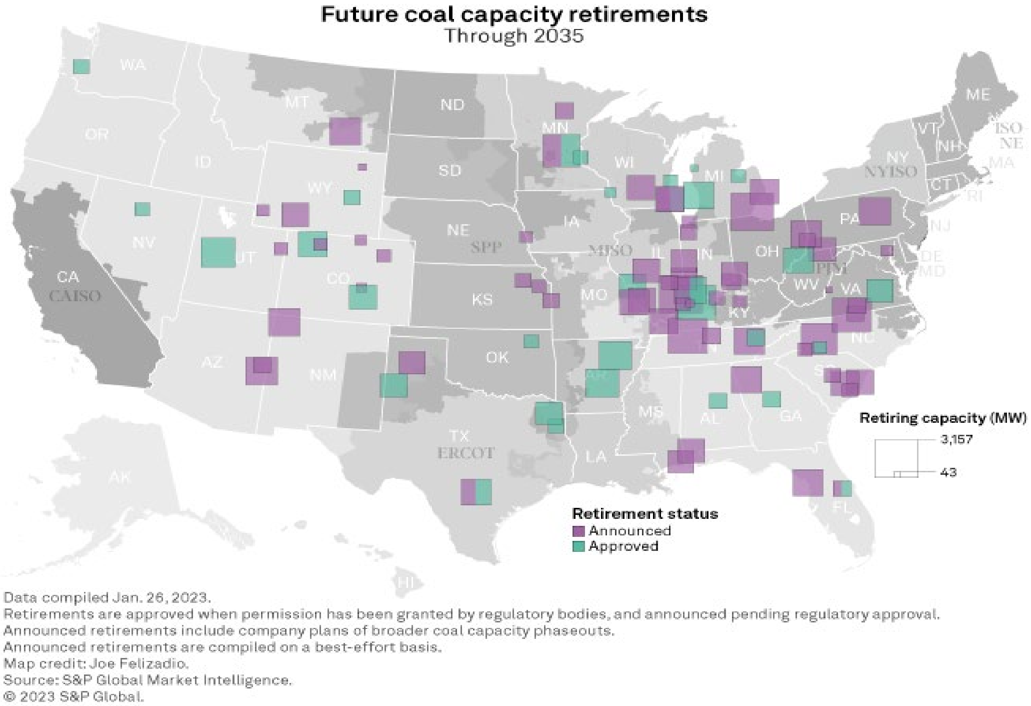




EIA, Inventory of Generators, January 2021 and May 2023

Figure 30 – Map of Planned Coal Capacity Retirements as of 2022 and up through 2035: Announced and/or Approved as of February 2023

From S&P Global:



T. Kuykendall et al, "Inflation Reduction Act to accelerate US coal plant retirements," S&P Global Market Intelligence, February 10, 2023, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/inflation-reduction-act-to-accelerate-us-coal-plant-retirements-74196498

Assuming that all planned retirements end up going into effect as indicated, there would be 144 GW of coal plant capacity in operation and without an announced retirement date. Of that amount, 49 GW entered service before 1975 and is already nearly 50 years old. By 2030, if all of this capacity is still operating, more than half of it (74 GW) would be over 50 years old. (Recall that the average age of capacity retired between 2016 and 2023 is 48 years.)

As new generating capacity and storage facilities with no or low variable costs enter service (in part supported by financial incentives provided under federal law) and is dispatched ahead of fossil generating units (like coal) with higher variable costs, the capacity factor of many coal plants will continue to deteriorate, rendering many of these now-operating coal plants less economic to operate and maintain and less financially viable in the future. It would be reasonable to expect much of this older and less efficient coal-plant capacity with low utilization to move into retirement and decommissioning. The timing of owners' decisions about individual plants remains uncertain today, although the EIA's most recent Annual Energy Outlook (based on the reference case which assumes current policy as of the end of 2022) projects that there would be 102 GW of coal-plant capacity in operation in 2030, dropping to 97 GW by 2032, 91 GW by 2035, and 77 GW by 2040.[58]

[58] EIA, Annual Energy Outlook 2023, Table 9, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2023&cases=ref2023&sourcekey=0.

D. Other Factors Potentially Affecting the Timing/Location of Further Coal Unit Retirements

In addition to the impacts of these two new federal statutes and the other factors already putting pressure on coal plant retirements, there are several uncertainties that may affect the timing of coal retirements, whether planned or unplanned at present. Many studies have examined transitions of the U.S. electric system resulting from such things as changes on the supply side (e.g., expansion of the transmission grid, deployment of utility-scale and distribution clean-power technologies) and on the demand side as well (e.g., impacts from electrification of heating systems in buildings and adoption of electric vehicles, implementation of more flexible demand).[59] The pace of commercial readiness and adoption of some advanced technologies (e.g., advanced nuclear) is uncertain, as is the pace of other things (e.g., the uptake of buildings' conversions to electric heating systems). States' policies affecting retail rate design and transitions of local natural gas use will affect such transitions, but in as-yet unknown ways. Local reliability considerations may keep even some relatively poor performing coal plants in operation until local capacity and electric energy needs can be assured through some combination of new power plants, energy efficiency investments, flexible demand, transmission enhancements, or other actions.

Another uncertainty affecting the timing of retirements, especially of coal-fired power plants with low-to-mid-level utilization rates, is the outcome of the current rulemaking underway with respect to federal regulation of GHG emissions from existing fossil-fuel power plants. In May of 2023, the EPA announced its proposed rules to regulate such emissions.[60] According to EPA, the agency intends to finalize new rules by 2024, after receiving and considering comments submitted by the public by August 8, 2023.

The final rule will not be known, therefore, until EPA issues its new regulations – and ultimately until it is implemented in the plans developed by the states and in the actions of owners of affected generating units.

As EPA has explained about its proposed regulation, it provides different approaches to the "Best System of Emission Reduction" ("BSER") for large and frequently used GHG-emitting generating units and for less frequently used units, depending on the date upon which a particular affected unit is shut down for retirement. As shown in Figure 31, EPA's proposal indicates that if the owner of a coal-fired boiler intends to operate the unit beyond the end of 2039, it would have one type of BSER, while units that cease operations before January 1, 2040 would have different BSERs applied to them – that is, one BSER "for units that cease operations before January 1, 2032, and units that cease operations after January 1, 2035, that adopt enforceable annual capacity factor limit of 20%" and another BSER for "units that cease operation before January 1, 2040 and are not in other subcategories."[61] These different approaches are illustrated on a time line prepared by the Harvard Environmental & Energy Law Program, as shown in Figure 32.

---

[59] National Academies of Sciences, Engineering and Medicine, *The Future of Electric Power in the U.S.*, 2021, https://nap.nationalacademies.org/catalog/25968/the-future-of-electric-power-in-the-united-states; National Academies of Sciences, Engineering and Medicine, Accelerating Decarbonization in the United States: Technology, Policy and Societal Dimensions, 2021, https://www.nationalacademies.org/our-work/accelerating-decarbonization-in-the-united-states-technology-policy-and-societal-dimensions.

[60] https://www.federalregister.gov/documents/2023/05/23/2023-10141/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed.

[61] EPA, "Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units," Stakeholder Presentation, May 2023, https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf.

Figure 31 – EPA Proposed Regulation for GHG Emissions From Power Plants

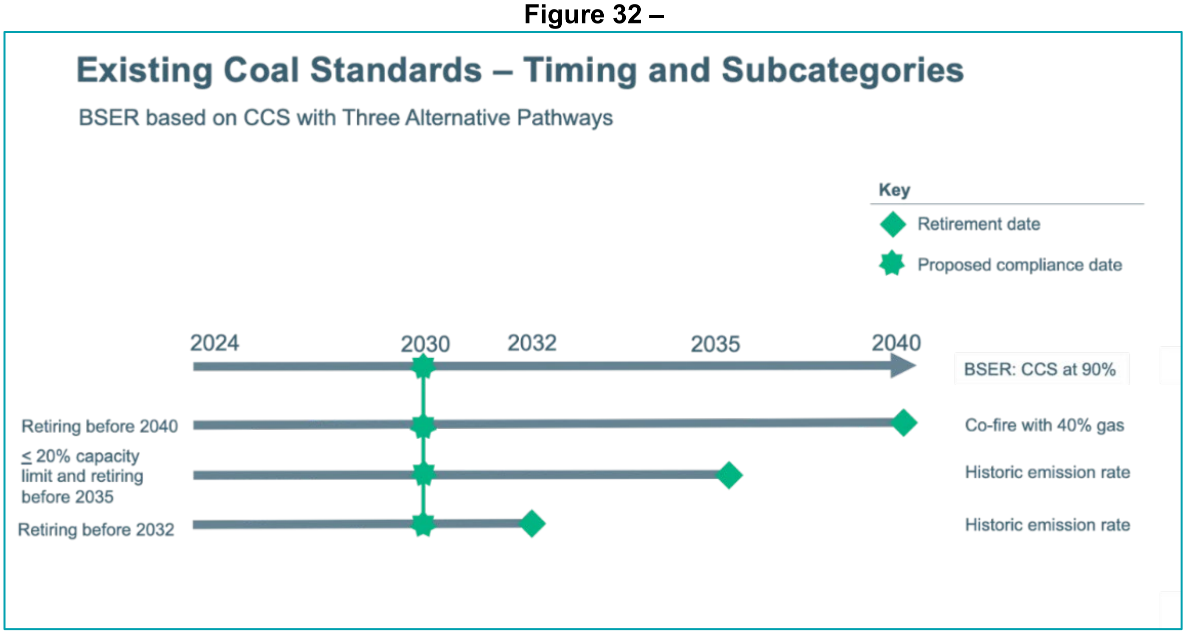
PROPOSED BSER LEVELS FOR 111D – EXISTING COAL, OIL AND NATURAL GAS-FIRED BOILERS AND LARGE, FREQUENTLY USED NATURAL GAS COMBUSTION TURBINES

Coal-Fired Boilers	Natural Gas and Oil-Fired Boilers	Natural Gas Combustion Turbines
For units operating past December 31, 2039, **BSER:** CCS with 90% capture of CO_2 an (88.4% reduction)	**BSER:** routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross).	For turbines >300MW, >50% capacity factor **CCS Pathway BSER:** By 2035: highly efficient generation coupled with CCS with 90% capture of CO_2 (90 lb CO_2/MWh) **Low-GHG Hydrogen Pathway BSER:** By 2032: highly efficient generation coupled with co-firing 30% (by volume) low-GHG hydrogen (680 lb CO_2/MWh) By 2038: highly efficient generation coupled with co-firing 96% low-GHG hydrogen (90 lb CO_2/MWh)
For units that cease operations before January 1, 2040 and are not in other subcategories, **BSER:** co-firing 40% (by volume) natural gas with emission limitation of a 16% reduction in emission rate (lb CO_2/MWh-gross basis)		
For units that cease operations before January 1, 2032, and units that cease operations after January 1, 2035, that adopt enforceable annual capacity factor limit of 20%, **BSER:** routine methods of operation and maintenance with associated degrees of emission limitation of no increase in emission rate		

The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kgCO_2e/kgH_2 overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).

EPA, "Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units," Stakeholder Presentation, May 2023, https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf.

Figure 32 –



https://eelp.law.harvard.edu/2023/05/epa-proposes-new-rules-to-combat-climate-changing-pollution-from-power-plants/

There are features of the proposed GHG regulations for existing fossil generating units that dovetail with power system and market realities as they now and are anticipated to exist in upcoming years: that is, that some fossil fuel generating units will operate infrequently now and in the years ahead and may be good candidates (e.g., from a financial point of view) for retirements in the not-too-distant future, while other fossil units are likely to show promise for operating in economically viable ways for many years into the future. The flexibility that is built into the proposed approach recognizes that owners of these generating units have multiple considerations to take into account as they analyze their options in the future: the likelihood that a plant will or will not operate in current electricity markets, its profitability given its age and size and location, its need for reliability purposes, and the economics of adding different compliance strategies at different costs in light of all of those factors.

As summarized by the Harvard Environmental & Energy Law Program: "If a coal plant plans to operate for a long time (i.e., beyond 2040), EPA is proposing to require those plants to run pollution controls by 2030. But if a company plans to continue to operate a coal plant until 2035 or 2040, then EPA proposes standards based on how much it will run or what fuels it uses. If a plant is planning to retire by 2032, the rule doesn't ask companies to make costly investments."[62]

[62] "EPA proposes new rule to combat climate changing pollution from power plants (Timelines)," HEELP, https://eelp.law.harvard.edu/2023/05/epa-proposes-new-rules-to-combat-climate-changing-pollution-from-power-plants/. *See* also: Carrie Jenks, Hannah Oakes Dobie, Hannah Perls, Sara Dewey, "EPA's Proposed Greenhouse Gas Emission Standards for Power Plants are Consistent with Statutory Factors and Market Trends," HEELP, May 19, 2023, https://eelp.law.harvard.edu/2023/05/epas-proposed-greenhouse-gas-emission-standards-for-power-plants-are-consistent-with-statutory-factors-and-market-trends/.