National Coal Council

Maximizing the Value of the U.S. Coal Fleet

July 2026

Prepared by the National Coal Council

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July 21, 2026

Dear Secretary Wright:

On behalf of the National Coal Electricity Subcommittee, we are pleased to submit our report, *Maximizing the Value of the U.S. Coal Fleet*. We dedicate this report to you and President Trump in recognition of your foresight and leadership in reestablishing the National Coal Council (NCC) and enabling the NCC to provide you with the recommendations that are described in the report.

Electricity is the lifeblood of the United States, and the American electricity grid now faces one of its greatest challenges in generations. During World War II, U.S. electricity generation surged to support the industrial mobilization needed to produce the aircraft, tanks, ships, and munitions that helped win the war. Coal-fueled power helped fuel that victory abroad and the postwar prosperity that followed at home.

Today, the United States faces a new era of strategic competition, with artificial intelligence (AI), advanced manufacturing, electrification, and broader economic growth driving renewed demand for reliable and affordable electricity. Yet, as described in this report, federal and state policies have undermined the nation's ability to maintain the abundant, reliable, and affordable power needed to meet this moment. These policies and regulations have caused or contributed to the retirement, so far, of enough coal-fueled generation since 2011 to power 62 million households, or equivalent to the total power supply of the states of California and New York combined. Federal, regional, and state policies have also undermined the economics of the remaining coal fleet, increasing the pressure to retire even more coal power plants despite the critical need for the electricity they produce.

Coal power plants must continue to operate because of their many advantages, beginning with costs – most states with low-cost electricity have a higher share of coal generation – and relying on existing coal-fueled generation is much less costly than building replacement generation, whether nuclear, natural gas, wind, or solar. Coal power plants are dispatchable, which means they can be ramped up and down depending on the demand for electricity, and are not dependent on the sun or wind. They have a high capacity value, which is a measure of dependability when electricity demand peaks. They are supported by on-site fuel inventories and able to provide affordable electricity because of stable coal prices and long-term fuel contracts. They also provide essential reliability services and other reliability attributes that keep the grid stable; are resilient as demonstrated by their ability to increase output during winter storms; contribute to a diverse electricity mix; and promote energy independence because the United States has more coal reserves than any other country.

For the past several years, the U.S. electricity grid has been undergoing profound changes, leaving regulators, ratepayers, industry officials, and others to wrestle with many challenges. These include higher electricity prices; large increases in electricity demand; the replacement of aging infrastructure; the risk of capacity shortages caused in part by the retirement of coal power plants; and the loss of attributes that are essential for grid reliability. Coal-fueled generation can help meet these challenges if policies, regulations, and programs are designed to preserve and modernize the coal fleet. Running our existing coal fleet at historic operating rates represents some of the best incremental generation to provide reliable and affordable electricity and help solve the nation's generation needs in the coming years.

Sincerely,

Jim Grech
James Grech
National Coal Council Chair

Jimmy A Brock
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National Coal Council Vice Chair

Michelle A. Bloodworth
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Electricity Subcommittee Chair

1. Executive Summary

Overview

Coal and the nation's fleet of coal power plants have been an essential part of the U.S. electricity grid for more than a century, with coal generating half the nation's electricity as recently as 2008, the same year domestic coal production peaked. The U.S. coal fleet remains a critical national asset as the electricity grid enters a period of renewed demand growth, rising reliability risks, and increasing concern over the affordability of electricity.

After nearly 15 years of flat electricity demand, the grid must now support rapid growth from data centers, AI, manufacturing, electrification, and broader economic activity. Despite this demand growth, dispatchable capacity remains at risk of retirement, with financial pressures expected to increase to the extent new loads are encouraged or required to obtain their electricity from only new generation resources. For net capacity increases to occur, existing generation resources must be retained even as new resources are added to the grid. Retaining and operating the existing coal fleet through at least the 2040s remain one of the most cost-effective pathways to maintain grid reliability.

The decline of the coal fleet has not been caused by market forces alone. It has been driven by politicized environmental regulations, regulatory uncertainty, subsidized competing resources, state mandates, and market structures that do not fully value and compensate coal power plants for their reliability and fuel-security attributes. Preserving and modernizing existing coal power plants is generally less expensive than replacing them with new capacity, which can take several years to build.

This report includes background information that forms the basis for recommendations that, if implemented, will help preserve and modernize the coal fleet. The recommendations below summarize the major actions described in the report.

Recommendations

This report finds that the administration should repeal or revise unnecessary and expensive environmental regulations, reform power market practices, provide financial support to modernize the coal fleet, remove impediments to coal production, and support the development of new coal power plants. Furthermore, we recommend that the Department of Energy (DOE) establish a process to monitor and report on progress toward implementation of the recommendations. The members of the NCC stand ready to assist DOE in this process.

Regulatory Reforms

- The Environmental Protection Agency (EPA) has made progress modifying and repealing some regulations. We recommend that the agency make a priority of finalizing the repeal of greenhouse gas (GHG) regulations for new and existing coal power plants and the underlying Endangerment Finding, repealing the 2024 Effluent Limitations Guidelines (ELG) rule, and reforming New Source Review (NSR).

- Regulatory certainty is essential for efficient planning and investing. Congress should codify changes to regulations that are promulgated by EPA. Durable certainty would allow plant owners, grid operators, and investors to make long-term decisions based on affordability and reliability rather than attempting to comply with constantly changing regulations.
- DOE should collaborate more closely with EPA, the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and grid operators to properly analyze the impacts of proposed and existing regulations on grid reliability and resource adequacy.
- DOE should work with states and grid operators to identify coal power plants that have entered into agreements with the federal government and/or non-governmental organizations (NGOs) that require the retirement of plants whose retirement poses a threat to reliability and resource adequacy. Once identified, DOE should work with plant owners, state authorities, and others to void or modify these agreements.
- The Department of the Interior (DOI) should continue efforts to resume, streamline, and provide certainty around leasing and permitting of federal coal reserves – including reforming Fair Market Value determinations. In addition, Congress should continue to codify leasing reforms that modernize the federal coal leasing program by amending the Mineral Leasing Act to provide for bonus payments of certain coal leases.
- DOI and the Advisory Council on Historic Preservation (ACHP) should negotiate a national Programmatic Agreement for energy infrastructure, and ACHP should issue a categorical exemption for scientific and geological sampling. DOI should define “ground disturbance” with thresholds below which archaeological review is not triggered.

Electricity Market Reforms

- The price-distorting impact of subsidized resources should be remedied by adopting durable minimum offer price rules in all FERC-jurisdictional markets.
- DOE should work with FERC and grid operators to convert Federal Power Act Section 202(c) orders, which have prevented plant closures for short periods of time, into longer-term reliability-must-run (RMR) agreements that allow for longer-term planning and proper compensation for plant owners.
- FERC should direct grid operators to assess the effective load carrying capability (ELCC) of generation resources to incorporate the value of dispatchability and on-site fuel that are essential for operation during extended reliability events to support increasingly stressed grid conditions. ELCC methodologies should also incorporate a more forward-looking approach that reflects generator upgrades and plant investments that can improve resource adequacy during periods of system stress.
- FERC should direct grid operators to identify and properly value all reliability attributes, especially fuel security. FERC should ensure that gas-fueled power plants without fuel security

(on-site storage or firm contracts) are not dispatched ahead of lower-cost coal-fueled generation through "advanced commitment" without proper compensation for displaced coal-fueled generation and fuel suppliers.

- DOE and FERC should incentivize bilateral contracting, including the co-location of large loads and existing coal power plants, by offering fast-track interconnection treatment and other streamlined permitting requirements.
- Large-load interconnection and co-location policies should encourage the efficient use of existing generation and transmission infrastructure while supporting new resource development. Policymakers should ensure that large-load growth contributes to overall system reliability and resource adequacy by enabling long-term contracting arrangements, efficient utilization of existing grid infrastructure, and timely development of new generation where needed. Also, load forecasting should be improved to assure efficient resource planning.
- FERC should compensate power plants for operating at minimum load to maintain reliability.

Financial Support

- To help preserve the coal fleet, DOE should increase both grants and loan guarantees for investments to modernize and preserve existing coal power plants and should streamline the process for approving grants and loans.
- The Department of War (DOW) should procure a meaningful amount of power from coal power plants through a clearly defined request for proposals and the award of both contracts and task order-based power purchase agreements.
- The Defense Production Act (DPA) should be used to provide financial support to domestic manufacturers of equipment and parts used in coal power plants. Federal policy should also support the broader coal supply chain, including coal production and transportation infrastructure.
- DOE should identify coal power plants that are dependent on a specific coal source and coordinate with DOI to ensure that these coal sources receive coal leases, mine plan approvals, and reclamation permits that are needed to supply the plants.

New Coal Power Plants

- DOE should designate a specific amount of loan guarantee authority for new coal power plants and establish a grant program using DOE's nuclear and Carbon Capture and Storage (CCS) demonstration competitions as a model.
- Besides providing financial support for new coal power plants, DOE should assess the regulatory and policy roadblocks that impede the development of new coal power plants and provide recommendations to remove these roadblocks.

2. Introduction

This report, *Maximizing the Value of the U.S. Coal Fleet*, is authored by the NCC Coal Electricity Subcommittee. The NCC was reestablished by the Secretary of Energy on June 16, 2025, to provide advice, information, and recommendations to the Secretary on a continuing basis regarding general policy matters relating to coal and the coal industry.[1] The report describes the history and status of the coal fleet, the value of the coal fleet and its contribution to reliable and low-cost electric power, the change in power markets with renewed demand growth, and actions that can be taken to support the coal fleet.

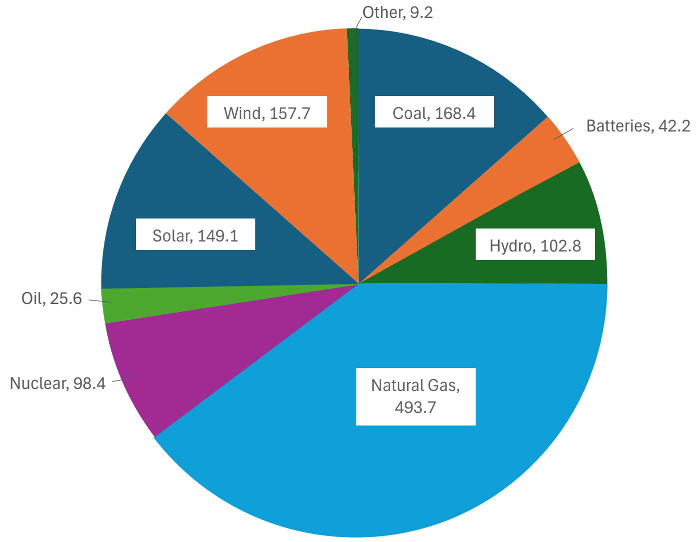
3. Profile of the Nation's Coal Fleet

Status of the U.S. Coal Fleet

The U.S. coal fleet remains a cornerstone of the nation's electricity generating infrastructure. As of December 2025, the fleet comprises 374 coal-fueled generating units at 186 power plants across 37 states, representing over 168 gigawatts (GW) of installed electric generating capacity (winter demonstrated capacity). Coal power plants account for approximately 13% of total U.S. installed generating capacity, second only to natural gas, whose 520 GW of capacity comprises over 40% of the national total. In many important power regions, coal provides a much higher share of capacity. For example, coal-fueled generating capacity represents close to a quarter of the total generating capacity of the Midcontinent Independent System Operator (MISO) region.

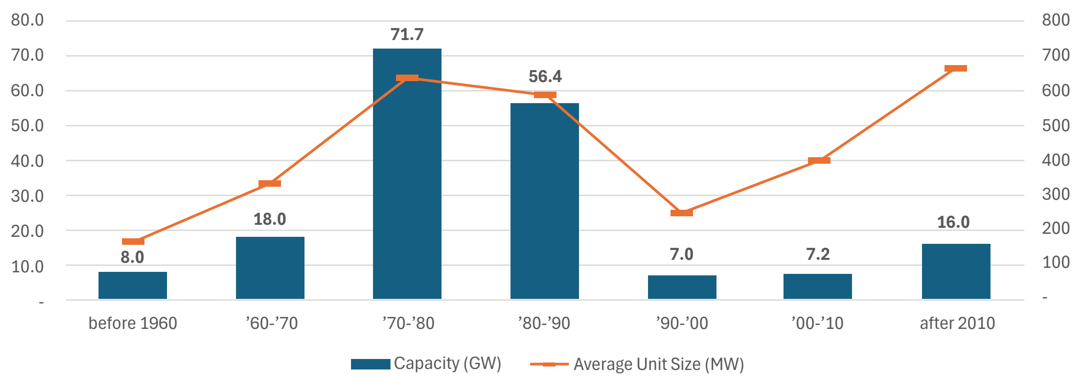
[1] https://www.federalregister.gov/documents/2025/06/18/2025-11223/national-coal-council.

Figure 1 - U.S. Generating Capacity as of Dec. 2025[2]



The coal fleet spans a wide range of ages, with units ranging from 13 to 73 years in operation. The newest coal power plants started operations during 2010-2013, with 19 new units, totaling almost 12,400 megawatts (MW) in 11 states. These high efficiency, low emissions coal units average over 650 MW each, underscoring the continued technical viability of coal-fueled generation at large scale. The oldest units still in operation date back to 1953 at the Tennessee Valley Authority's Shawnee power plant in Paducah, Kentucky. They are a testament to the durability and continuing value of well-maintained coal infrastructure. Most of the active fleet, roughly 70%, started operation between 1970 and 1990. This large, established base of generating capacity represents decades of capital investment that would cost far more time and money to replace than to preserve and modernize.

Figure 2 - U.S. Coal Units Built by Decade[3]



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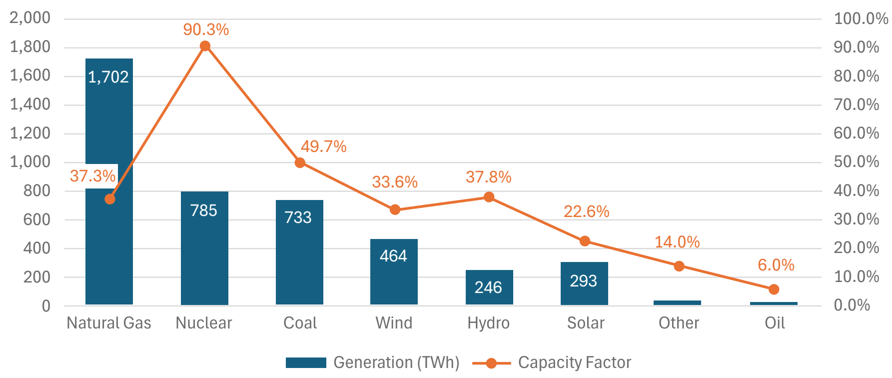
[2]Source: https://www.eia.gov/electricity/data/eia860m.
[3]Source: EIA-860 (https://www.eia.gov/electricity/data/eia860) data.

In terms of generation, coal power plants ranked third among all fuel types in 2025, producing 733 terawatt-hours (TWh), approximately 17% of total U.S. electricity generation. Perhaps more striking is the fleet's utilization which achieved an average capacity factor of 50% in 2025, the second highest of any fuel type, surpassing natural gas (37%) and trailing only nuclear (90%). The coal fleet can operate at much higher output, as the average national capacity factor was over 70% from 2000 through 2008.

Figure 3 - 2025 U.S. Generation & Capacity Factor by Fuel Type[4]



Recent History of the U.S. Coal Fleet (2010 – 2025)

The story of the U.S. coal fleet over the past 16 years is, in part, a story of harmful policy choices – not market forces alone – that have systematically disadvantaged coal-fueled generation in favor of heavily subsidized alternatives. Since 2010, nearly 154 GW of coal-fueled capacity have been retired or converted to natural gas, a decline of almost 45% from the fleet's peak, leaving about 168 GW of coal-fueled capacity operating today. No new coal power plants have entered commercial operation since 2013, despite coal remaining one of the most abundant and lowest-cost domestic energy resources.

Annual coal retirements peaked in 2016 at over 20 GW, driven in large part by compliance deadlines under the Mercury and Air Toxics Standards (MATS) rule. Between 2015 and 2024, retirements and conversions averaged more than 13 GW per year – a relentless attrition driven by a convergence of aggressive federal environmental regulations, the post-shale-revolution drop in natural gas prices, federally subsidized buildouts of new wind and solar capacity, state renewable electricity mandates, and state-level subsidies for existing nuclear plants, all during a prolonged period of essentially flat electricity demand. Encouragingly, the sharp rebound in electricity demand in recent years has begun to reverse this trend. In 2025, coal retirements and conversions fell to just 6.3 GW, the lowest level since 2013, as grid operators and utilities recognized the irreplaceable reliability value of the remaining coal fleet.

While the coal fleet has been shrinking in the United States, new coal power plants continue to be built to supply power to the fast-growing economies of China, India, and Southeast Asia. Global construction of new coal power plants has averaged over 60 GW annually since 2020.[5] Currently, almost 467 GW of new coal-fueled generation are under development in other countries.

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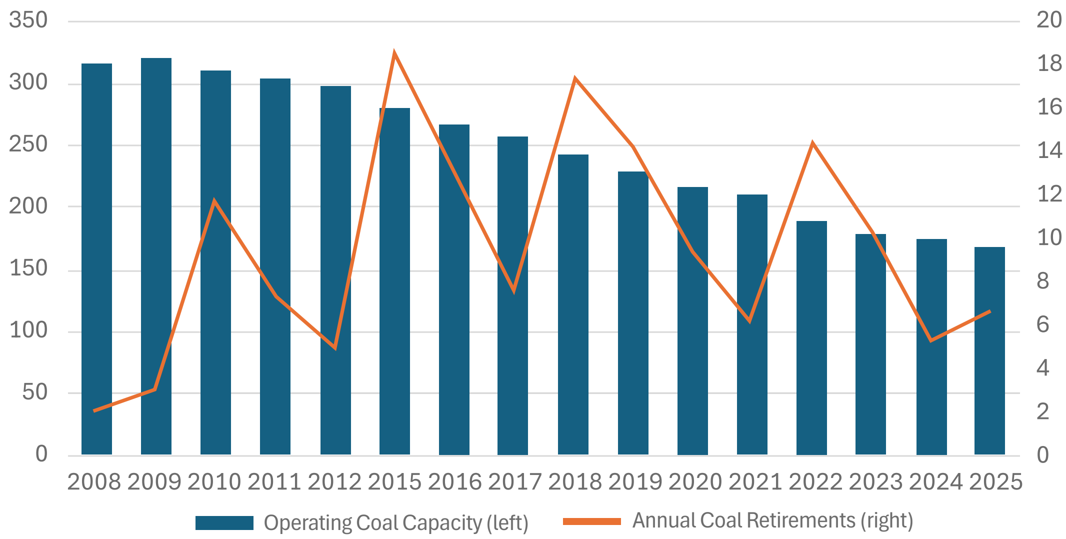
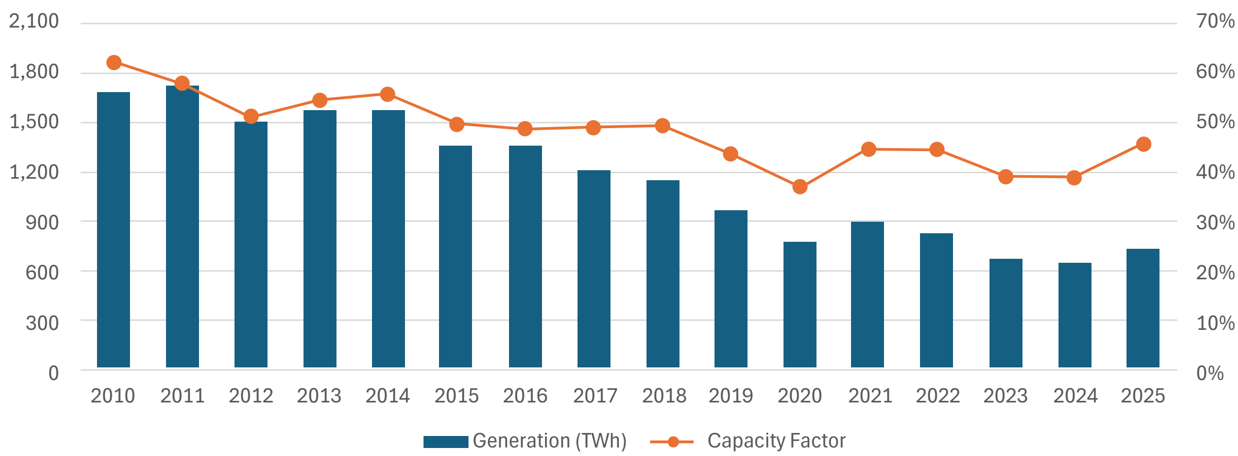
[4]Source: Analysis of 2025 EIA-860 (https://www.eia.gov/electricity/data/eia860/) and EIA-923 (https://www.eia.gov/electricity/data/eia923/) data.
[5]Global Energy Monitor at https://globalenergymonitor.org/projects/global-coal-plant-tracker.

Figure 4 - U.S. Coal Capacity (GW)[6]



Coal-fueled generation has been in steady decline since its 2008 peak, falling nearly 60% by 2025, with only brief recoveries in years when natural gas prices spiked. The average capacity factor of the coal fleet declined from 72% in 2008 to a low of 41% in 2020, reflecting the COVID-19 pandemic. The 50% capacity factor achieved in 2025 – the highest in seven years – signals that the coal fleet is responding to renewed demand for electricity.

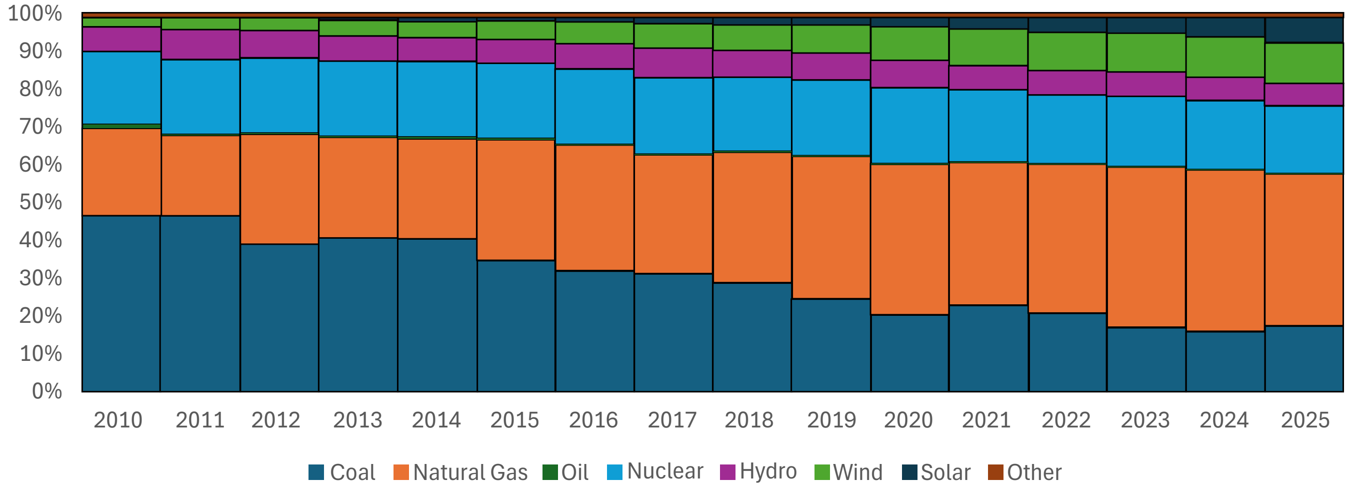
Figure 5 - U.S. Coal Generation (TWh) & Capacity Factor[7]



Coal's share of total U.S. electricity generation fell from 46% in 2010 – the highest of any fuel type – to 17% in 2025. Over that same period, natural gas's share rose from 23% to 40%, while the combined share of wind and solar surged from a negligible 2% to over 18%. These shifts reflect the profound transformation of the U.S. electricity generation mix, driven largely by policy intervention rather than any fundamental change in the underlying economics or reliability of coal power plants.

[6]Source: EIA-860 (https://www.eia.gov/electricity/data/eia860/) data.
[7]Source: Analysis of 2025 EIA-860 (https://www.eia.gov/electricity/data/eia860) and EIA-923 (https://www.eia.gov/electricity/data/eia923) data.

Figure 6 - U.S. Generation Mix by Fuel Type[8]



The coal power industry has made extraordinary investments in environmental performance over this period. Between 2000 and 2025, sulfur dioxide (SO_2) emissions from coal power plants declined by 93%, from over 10.7 million tons to just 705,000 tons. SO_2 emission rates at coal power plants dropped 83%, from over 1 pound per million Btu (lb/MMBtu) to just 0.17 lb/MMBtu. Nitrogen oxides (NO_x) emissions fell by 89%, with emission rates declining by 72% over the same period. These improvements represent one of the most dramatic pollution reductions achieved by any major industrial sector in U.S. history. Coal power plants collectively will have invested almost $124 billion in emission control technologies by 2030 driven by federal rules including the Cross-State Air Pollution Rule, MATS, the Ozone Transport Rule, and the Regional Haze Rule.

[8]Source: EIA Electricity Data Browser (https://www.eia.gov/electricity/data/browser).

Figure 7 - U.S. SO_2 Emissions from Coal Power Plants[9]

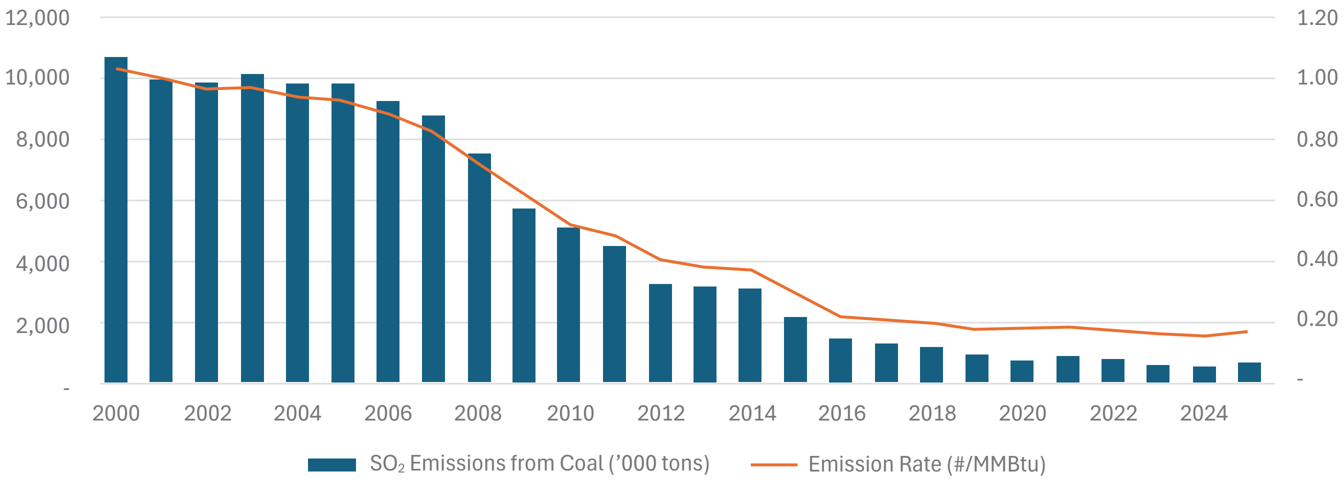
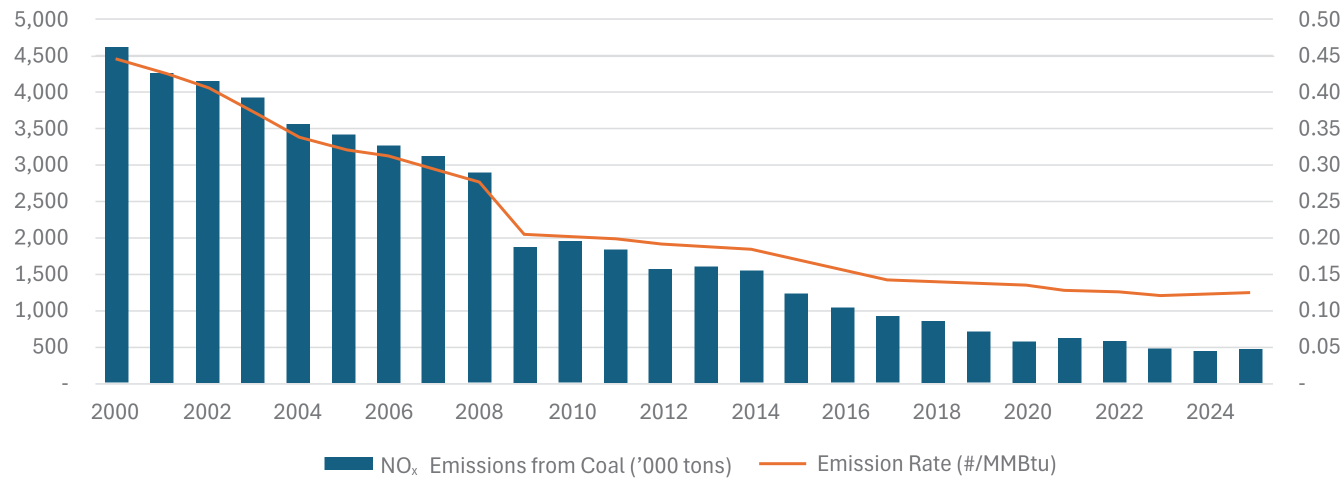


Figure 8 - U.S. NO_x Emissions from Coal Power Plants[10]



The decline in coal generation was largely driven by policy. Federal environmental regulations imposed during the Obama and Biden administrations challenged plant owners with costly compliance requirements and deep uncertainty about future regulatory demands, tipping the economic calculus toward early retirement. At the same time, the shale gas revolution fundamentally altered the competitive landscape. Natural gas prices delivered to U.S. power plants declined from $9.02/MMBtu in 2008 to $3.89/MMBtu in 2025,[11] spurring a near-tripling of natural gas-fueled generation over the same period as investors redirected capital toward new natural gas-fueled combined-cycle (NGCC) power plants. In an era of no growth in electricity demand, utilities were willing to retire existing coal power plants to make room for investments in new wind, solar, and natural gas power plants, decisions that were incentivized by ratemaking policies (providing returns on investment in new plants), approved by the governing state regulatory commissions, and supported by environmental groups that intervened in these cases.

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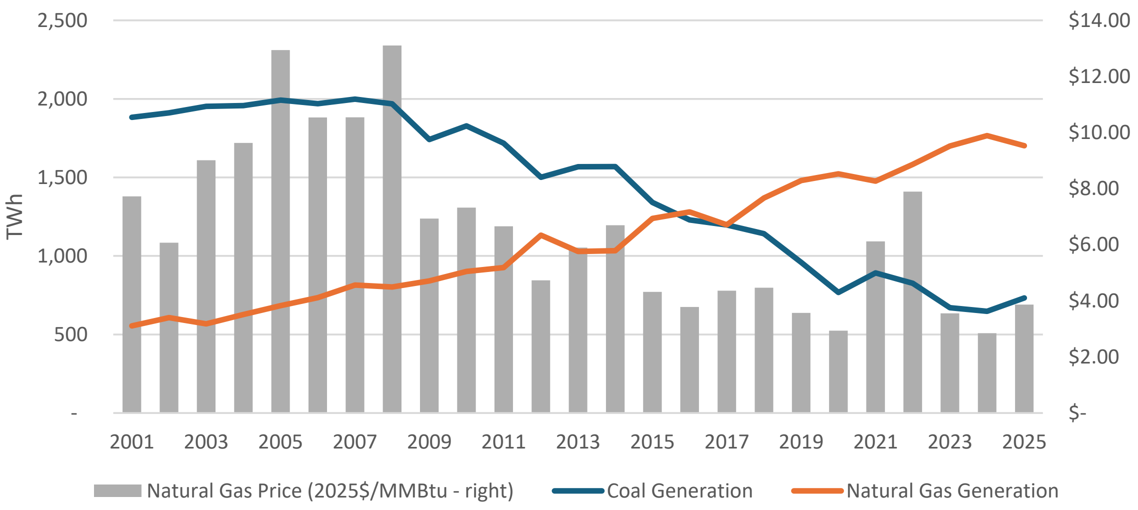
[9]Source: EPA Clean Air Markets Program Data (https://campd.epa.gov).
[10]Source: EPA Clean Air Markets Program Data (https://campd.epa.gov).
[11]Source: EIA Electricity Data Browser (https://www.eia.gov/electricity/data/browser).

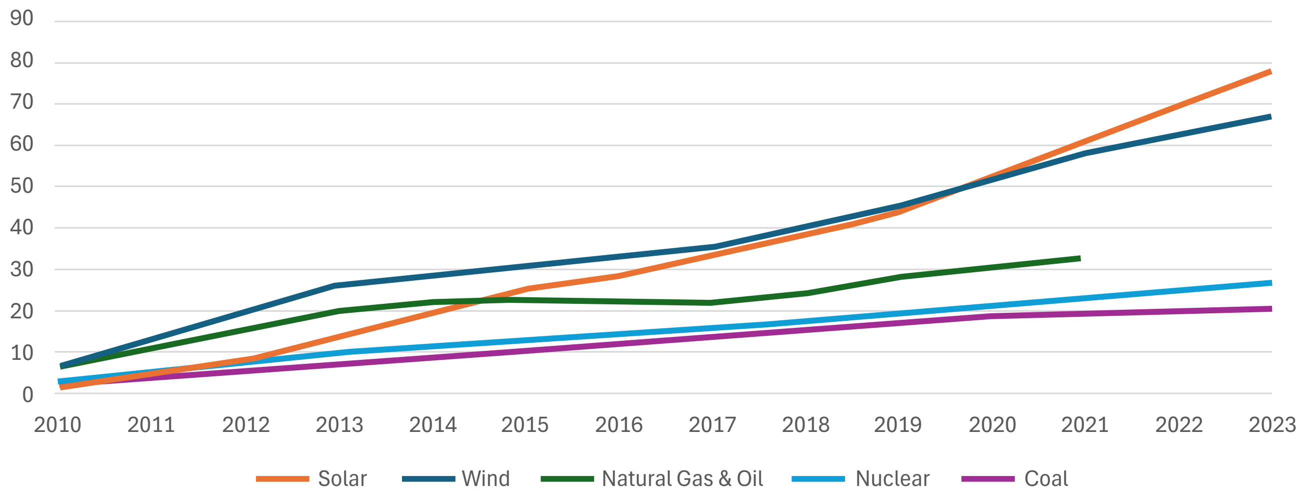
Figure 9 - U.S. Natural Gas and Coal Generation vs. Natural Gas Price Delivered to Power Plants[12]



Beyond natural gas competition, the coal fleet faced a tilted playing field created by massive federal and state subsidies for renewable energy and nuclear power. Production Tax Credits (PTC) and Investment Tax Credits (ITC), combined with state renewable portfolio standards (RPS) and clean energy standards (CES), directed unprecedented capital flows into wind and solar development. Between fiscal years 2010 and 2023, the federal government spent or forewent approximately $145 billion in tax revenues for wind and solar alone, compared to just $21 billion for coal, the lowest federal subsidy level of any of the six major generation fuel types. (Subsidies for the coal industry are now minimal after the expiration of the refined coal tax credit in 2020, little of which went to support coal generation.)[13] In addition, many states (including New York, Illinois, New Jersey, Connecticut, Ohio, and California) enacted dedicated subsidies to keep economically challenged nuclear plants operating when power market prices were low, a financial lifeline that was never extended to the coal power industry.

[12]Source: EIA Electricity Data Browser (https://www.eia.gov/electricity/data/browser).
[13]https://www.eia.gov/analysis/requests/subsidy.

Figure 10 - Cumulative Federal Subsidies (2010-24) $2024 billion[14]



Some states have enacted rules and regulations that are driving coal plant retirements and increasing retail power prices as a result. The most destructive of these rules are the cap-and-trade programs to force power plants to purchase emission allowances for CO_2, especially the Regional Greenhouse Gas Initiative (RGGI). The states that are part of RGGI have now closed every coal power plant except one in Maryland, which has not retired because it has been ordered to stay open by PJM to provide grid and transmission reliability.[15] These states plus California (which has its own cap-and-trade program) now have the highest retail power rates in the lower 48 states, which are directly correlated with their emission reduction programs. Other states have laws and regulations (such as CES and RPS) that will force coal power plants to close over the next decade – including Colorado, Illinois, Michigan, and Minnesota – likely resulting in lower reliability and higher retail power prices, as has happened in California and the RGGI states.

[14]Source: Texas Public Policy Foundation Report on Federal Subsidies (https://www.texaspolicy.com/wp-content/uploads/2024/10/2024-10-LP-Federal-Energy-Subsidies-BrentBennett_FINAL-1.pdf).
[15]Virginia recently joined RGGI and has two operating coal power plants.

Figure 11 - RPS/CES Targets by State[16]

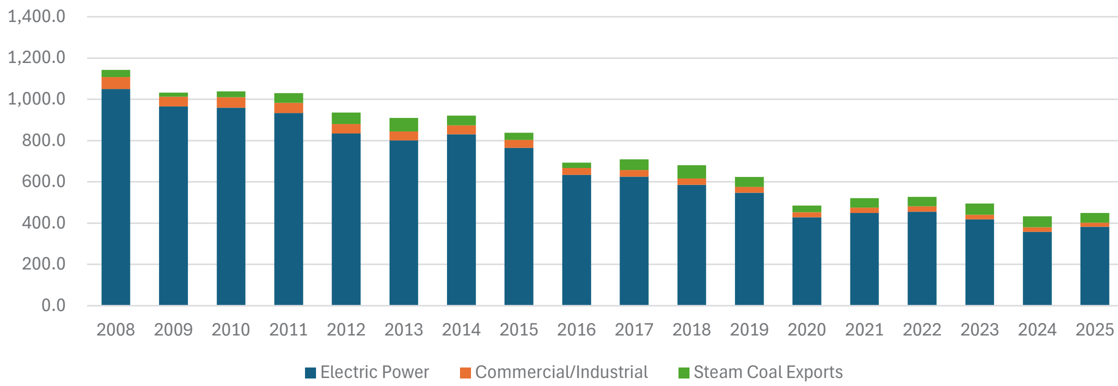
State	CES Target	Year	2025 CES %	RPS Target	Year	2025 RPS %
California	100%	2045	55%	60%	2030	36%
Colorado	100%	2050	44%	30%	2020	40%
Connecticut	100%	2040	65%	40%	2030	4%
Delaware	100%	2050	2%	40%	2035	2%
Hawaii	--	--	--	100%	2045	20%
Illinois	100%	2045	95%	50%	2040	23%
Indiana	10%	2025	17%	--	--	--
Iowa	--	--	--	105 MW	2015	13,734 MW
Kansas	--	--	--	20%	2020	72%
Maine	--	--	--	100%	2050	49%
Maryland	100%	2045	31%	50%	2030	3%
Massachusetts	100%	2050	6%	40%	2030	5%
Michigan	100%	2040	42%	60%	2035	14%
Minnesota	--	--	--	100%	2040	29%
Missouri	--	--	--	15%	2021	10%
Montana	--	--	--	15%	2015	43%
Nevada	--	--	--	50%	2030	45%
New Hampshire	--	--	--	25%	2025	10%
New Jersey	100%	2050	41%	50%	2030	3%
New Mexico	100%	2045	65%	80%	2040	65%
New York	100%	2040	46%	70%	2030	8%
North Carolina	100%	2050	44%	12.5%	2021	10%
North Dakota	--	--	--	10%	2015	51%
Ohio	--	--	--	8.5%	2026	7%
Oklahoma	--	--	--	15%	2015	52%
Oregon	100%	2040	68%	50%	2040	21%
Pennsylvania	18%	2021	57%	8%	2021	4%
Rhode Island	--	--	--	100.0%	2033	13%
South Carolina	--	--	--	2%	2021	5%
South Dakota	--	--	--	10%	2015	95%
Texas	--	--	--	10,000 MW	2025	68,969 MW
Utah	--	--	--	20%	2025	19%
Vermont	--	--	--	75%	2032	18%
Virginia	100%	2045	27%	100%	2045	8%
Washington	100%	2045	91%	15%	2020	11%
Washington, DC	--	--	--	100%	2032	1%
Wisconsin	--	--	--	10%	2015	9%

** calculated as 2025 in-state qualifying generation / in-state retail sales*

[16]Source: Analysis of DSIRE USA (https://dsireusa.org) and EIA-923 (https://www.eia.gov/electricity/data/eia923) and EIA-861 (https://www.eia.gov/electricity/data/eia861) data.

The stakes for the broader coal economy are enormous. The electric power sector accounts for nearly 75% of total U.S. coal consumption. Domestic industrial and steelmaking markets represent only about 7% of demand, while metallurgical and thermal coal exports account for approximately 20%. This concentration means that even modest policy changes affecting the coal fleet – whether to preserve existing capacity or facilitate the buildout of new capacity – will have outsized consequences for coal producers, the railroads that depend on coal as one of their most important commodities, and the state and local governments that rely on coal-related tax revenues and royalties.

Figure 12 - U.S. Coal Consumption by End-Use Sector (Million Tons)[17]



4. Value of the Coal Fleet and its Supply Chain

Coal power plants provide reliability and fuel security for the electricity grid. The independent grid operators, responsible for ensuring a reliable supply of power, evaluate the reliability of different types of generating resources based on their performance at times of peak demand when the risk of electricity shortages is greatest. For their capacity market auctions, PJM and MISO accredit each type of capacity as a percentage of their maximum capacity that can be relied upon during periods of peak demand. PJM and MISO accredit coal for 83% and 90%, respectively, of their maximum capacity as reliable capacity, while they accredit natural gas at 60% and 66%, with wind and solar at much lower levels.[18]

Figure 13 - Capacity Accreditation by Fuel Type[19]

	Capacity Market Accreditation	
	PJM	MISO
Coal	**83%**	**90%**
Natural Gas	60%	66%
Wind	41%	29%
Solar	11%	26%

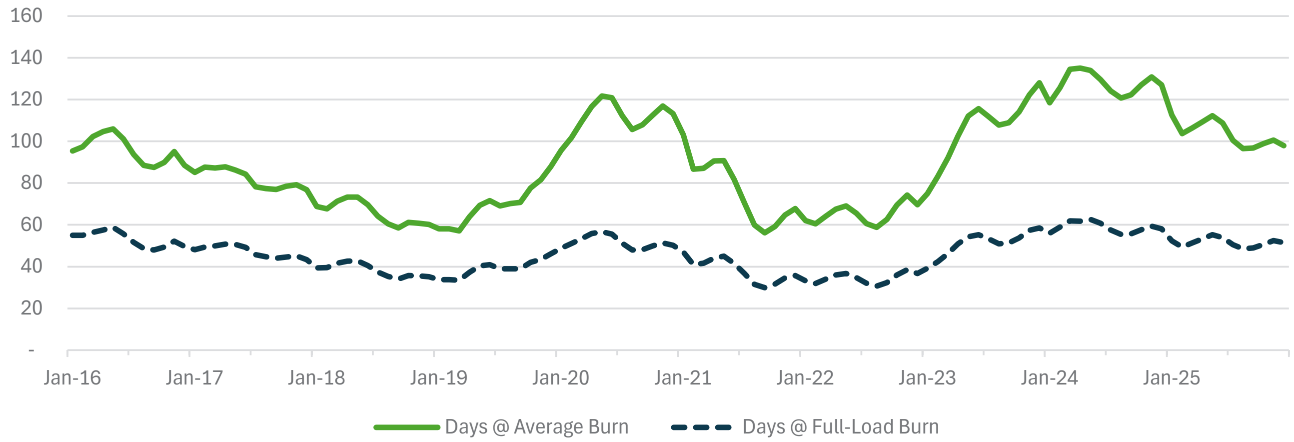
[17]Source: EIA Quarterly Coal Report (https://www.eia.gov/coal/production/quarterly).
[18]See "Ensuring Reliability: A Case Study of the PJM Power Grid," prepared for America's Power at https://americaspower.org/issue/ensuring-reliability/.
[19]Source: PJM (https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability) and MISO (https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy) capacity planning documents and EIA Hourly Electric Grid Monitor (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview) data.

Coal power plants contribute to the stability of the electricity grid because they are dispatchable – meaning that grid operators can dispatch the power plant (increase or decrease generation) when needed to match customer demand for electricity. Wind and solar facilities are inherently not dispatchable. They can only operate when the wind is blowing or the sun is shining, and grid operators cannot require wind and solar plants to increase generation to meet increased demand for power as they can for coal power plants. Compared to the other major sources of generating capacity – nuclear and NGCC plants – coal has greater ability to dispatch because coal power plants have greater turndown capability (the ability to reduce a plant to a lower level of operation without turning it off provides the grid operator with flexibility and reliability). On average, coal power plants can turn down generation to 40% of peak capacity, compared to 48% for nuclear and 49% for NGCC plants. Among major sources of power capacity, only simple cycle combustion turbines have greater turndown ratios than coal, but these plants are less efficient and are primarily used to meet peak demand.

The ability to dispatch a power plant provides grid operators with the critical ability to match power generation with load, and the large coal power plant steam turbine generators also provide the grid with inertia for voltage support. With further investment, the ability of coal power plants to follow load can be increased. Major utilities like PacifiCorp and Duke Energy have shown the ability to reduce the minimum load of their coal plants to only 10% - 20% of peak demand.

Coal power plants also provide critical on-site fuel security by maintaining large stockpiles of coal at the plants. This provides reliability in the event that fuel deliveries are interrupted due to adverse weather conditions or transportation problems. Coal power plants typically maintain on-site stockpiles of 30 – 60 days of maximum burn at full load. Plant operators use on-site fuel inventory to balance the market, allowing stockpiles to vary with demand while maintaining relatively regular deliveries. These coal stockpiles also function as a de facto battery by ensuring the availability of generating capacity and stable pricing in times of extreme weather.

Figure 14 - U.S. Coal Inventory at Coal Plants in Days of Consumption[20]



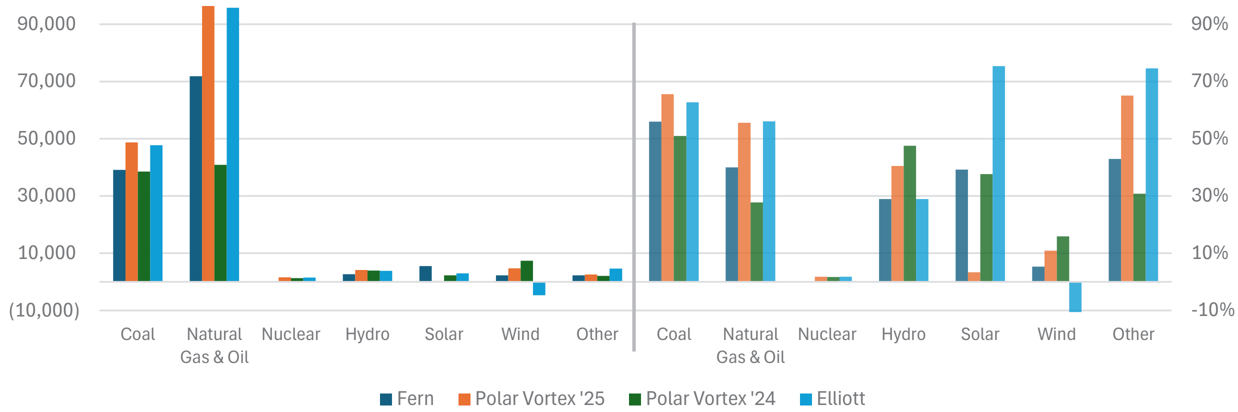
In contrast, virtually all natural gas power plants rely upon just-in-time delivery from the nationwide pipeline system. Few gas power plants maintain on-site storage of fuel oil (which requires an air permit that allows oil to be burned instead of natural gas) if gas supply is interrupted, and almost no gas power plants have on-site storage of LNG to provide fuel security.[21]

While just-in-time gas deliveries normally work well, they can be a problem during extreme cold winter storms, when demand for natural gas to heat houses and buildings is at its peak. During winter storm events over the last four years, coal generation has surged to meet increased power demand as the availability of natural gas was limited.

[20]Source: Analysis of EIA-923 (https://www.eia.gov/electricity/data/eia923) data.

[21]Recently, Dominion Energy received approval to build a new LNG storage facility to provide fuel security for two of its large gas power plants. Dominion stated "To avoid fuel shortages during extreme weather or other supply disruptions or constraints, Dominion Energy is adding liquefied natural gas (LNG) fuel storage at Greensville County Power Station. The Brunswick-Greensville Storage Facility will provide backup fuel supply to keep Greensville County and Brunswick County power stations operating for up to four days each and the lights on for more than 700,000 customers." https://www.dominionenergy.com/about/making-energy/power-stations/brunswick-greensville-storage-facility.

Figure 15 - Absolute (MW - left) and Relative Change (right) from Baseline during Previous Winter Storms[22]



Coal power plants have played a critical role in supporting power supply to consumers during extreme winter weather events. During these winter storms, power demand soars to supply home heating, and utilities must increase generation to meet this load. Failure to do so will result in widespread blackouts, such as the catastrophic event in Texas during Winter Storm Uri in February 2021.[23] During these winter storms, demand for natural gas jumps at the same time (also for home heating), which may limit the availability of natural gas to increase power generation. Since wind and solar plants are not dispatchable, grid operators cannot increase generation from these sources to respond to increased demand – in fact, winter storms can reduce wind and solar power generation due to snow and ice.

In the four extreme winter storm events since 2022, coal generation has provided a major source of increased power to meet load, with little increased generation from non-fossil sources (nuclear, hydro, wind, and solar). As shown on the chart above, coal generation responded to these storms with an increase in output of at least 50% above the baseline generation level in the weeks prior to the storm event. Without the fuel diversity provided by the coal fleet, it is likely there would have been major power blackouts.[24] In addition, reliance on the coal fleet during Winter Storm Fern saved ratepayers across four regions more than $1 billion.[25]

Also, coal provides the power industry with stable fuel prices, while natural gas prices fluctuate with swings in market conditions and even short-term winter weather. Adjusted for inflation, the delivered coal price for power generation has declined over the last 13 years. Even during global market disruptions, as occurred in 2022 after the invasion of Ukraine, delivered coal prices remained stable because most coal is purchased under longer-term contracts with fixed prices. In contrast, the average delivered cost of natural gas tripled from $2.41/MMBtu in 2020 to $7.27/MMBtu in 2022, while delivered coal prices were comparatively stable, increasing from $1.91/MMBtu to $2.36/MMBtu over the same period. The increase in natural gas prices from 2024 to 2025 spurred a 13% increase in coal-fueled generation as coal replaced gas in economic dispatch. The rapid growth of LNG exports could increase the volatility of natural gas prices by increasing the linkage to global natural gas markets. This is likely to increase the future reliance of the grid on coal-fueled generation to replace natural gas when global LNG prices are high.

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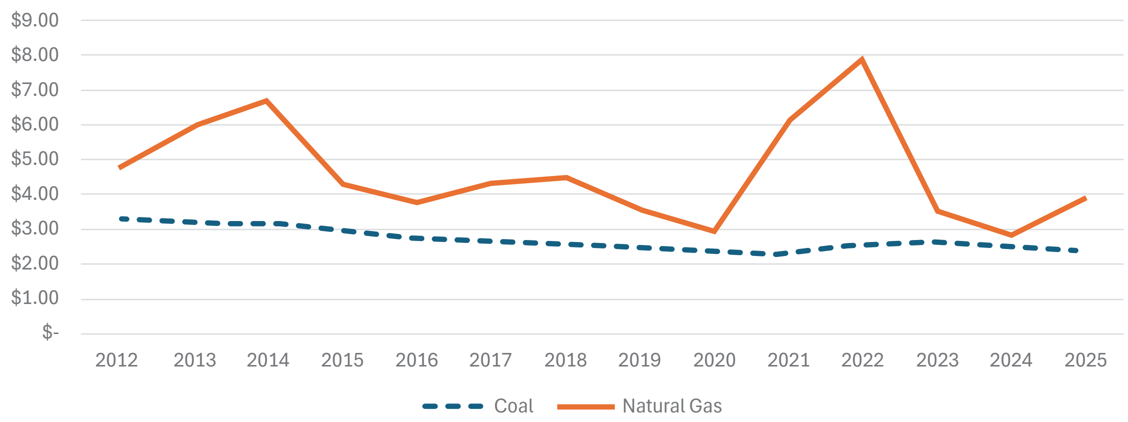
[22]Source: EIA Hourly Electric Grid Monitor (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview).
[23]Reliable power supply saves lives. The blackouts in Texas during Winter Storm Uri were responsible for 246 deaths, according to the Texas Department of State Health Services. https://www.dshs.texas.gov/sites/default/files/news/updates/SMOC_FebWinterStorm_MortalitySurvReport_12-30-21.pdf.
[24]See America's Power reports on Winter Storm Elliott (https://americaspower.org/issue/operation-of-the-u-s-power-generation-fleet-during-winter-storm-elliott/), Polar Vortex 2024 (https://americaspower.org/issue/operation-of-the-u-s-power-grid-during-the-january-2024-storm/), Polar Vortex 2025 (https://americaspower.org/issue/operation-of-the-u-s-power-grid-during-the-january-2025-polar-vortex/), and Winter Storm Fern (https://americaspower.org/issue/full-report-operation-of-the-u-s-power-grid-during-winter-storm-fern/).
[25]Energy Ventures Analysis, "Operation of the U.S. Power Grid During Winter Storm Fern," February 2026.

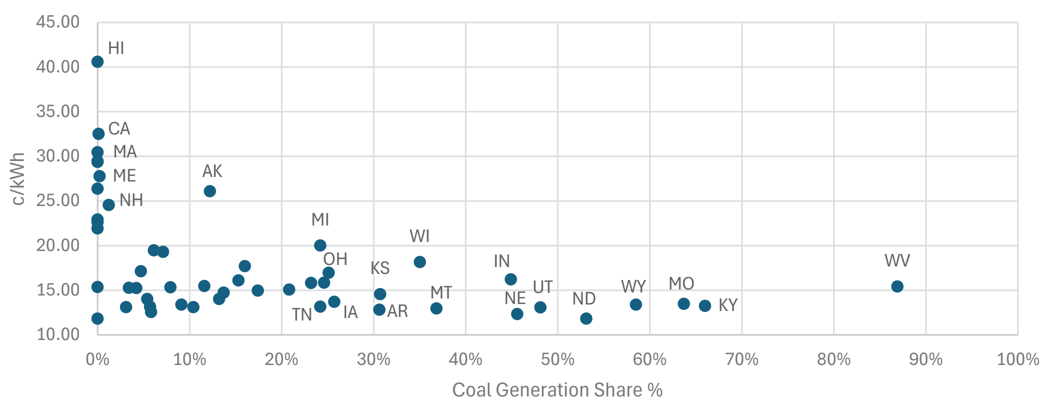
Figure 16 - Delivered Fuel Cost to U.S. Power Plants ($2025/MMBtu)[26]



A balanced portfolio of power generation, including coal and natural gas, protects consumers from high costs associated with overreliance on one fuel source. When natural gas prices are high (typically due to high demand from a cold winter), coal power plants ramp up output to replace gas-fueled generation, which reduces the cost of electricity to retail customers. Coal-fueled electricity generation also plays an important role in keeping natural gas prices from escalating. As natural gas prices rise, coal-fueled power generation displaces natural gas-fueled generation and thereby caps natural gas demand and provides consumers with price relief.[27] The flexibility to switch generation between natural gas and coal keeps power costs down and protects customers from spikes in volatile fuel prices. Coal is the only source of generation that provides flexibility to replace natural gas, as nuclear, wind, and solar generation cannot be ramped up for economic reasons and dependency on weather conditions.

Coal power plants have kept retail electricity rates lower in states that have preserved their coal fleets. Every state where the share of coal-fueled generation is greater than 25% had 2025 average retail power rates below the national average. States with high shares of coal-fueled generation have some of the lowest retail power rates in the country, including North Dakota, Nebraska, Wyoming, Kentucky, Utah, Montana, and West Virginia. In contrast, every state with retail power rates more than 25% above the national average has closed all its coal power plants (except Alaska, which has high power prices because of its remote location). In 2025, the 12 states that had no coal-fueled generation

Figure 17 - 2025 Coal Generation Share vs. Average Residential Retail Rate by State[28]



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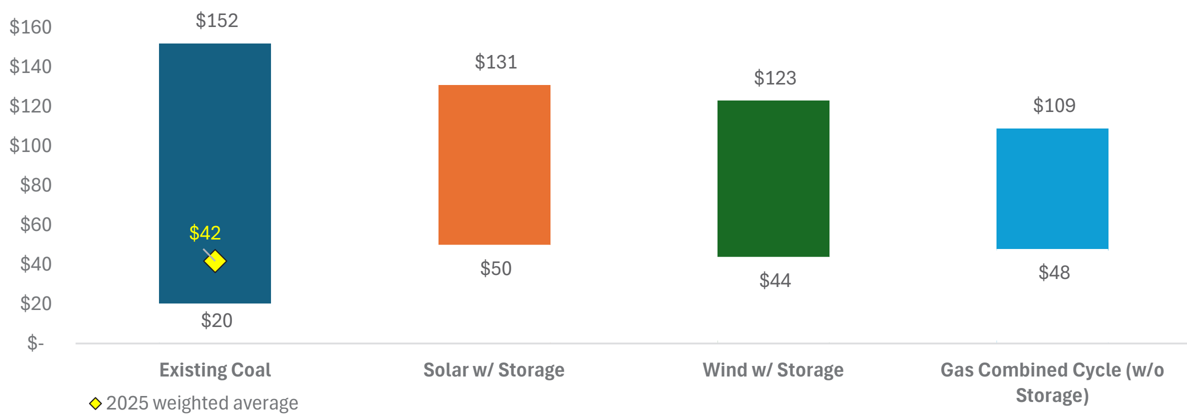
[26]Source: EIA Electricity Data Browser (https://www.eia.gov/electricity/data/browser).
[27]See *Comments of Paul Cicio, President & CEO, Industrial Energy Consumers of America, before the Federal Energy Regulatory Commission, April 24, 2025.*
[28]Source: Analysis of EIA-923 (https://www.eia.gov/electricity/data/eia923) and EIA-861 (https://www.eia.gov/electricity/data/eia861) data.

paid residential power rates of 25.94 cents per kilowatt-hour, 86% higher than the 12 states with the highest percentage of coal-fueled generation (over 30% supplied by coal).

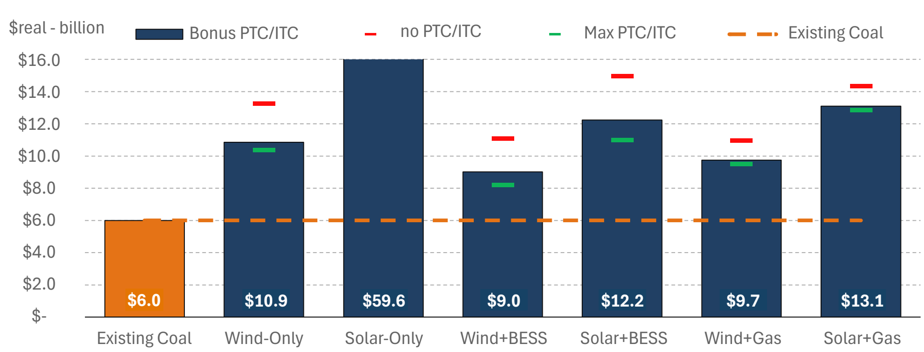
It is typically cheaper to operate and maintain existing coal power plants than it is to replace them with new sources of power generation. Based on the data filed by electric utilities on FERC Form 1, the average cost of coal-fueled generation in 2024 was $41.78 per megawatt-hour (MWh), including all fuel and operating costs. (The range of costs is wide as coal power plants that operate at low capacity factors have higher average costs due to spreading fixed costs over low utilization, but these plants are maintained to provide needed dispatchable capacity to ensure reliability.) In comparison, the cost of new power generation from natural gas, wind, and solar technologies ranges from $44 to $131 per MWh (levelized cost of energy, according to a recent report by Lazard).

Figure 18 - Existing Coal Generation Cost vs. New Firm Generation ($/MWh, w/o subsidies)[29]



In addition, the chart below shows that the cost of replacing almost 42 GW of retiring coal capacity with various combinations of wind and solar generation would be substantially greater than continuing to operate the retiring coal generation.

Figure 19 - Average Annual Cost - Existing Retiring Coal Fleet vs. New Renewable Energy[29]

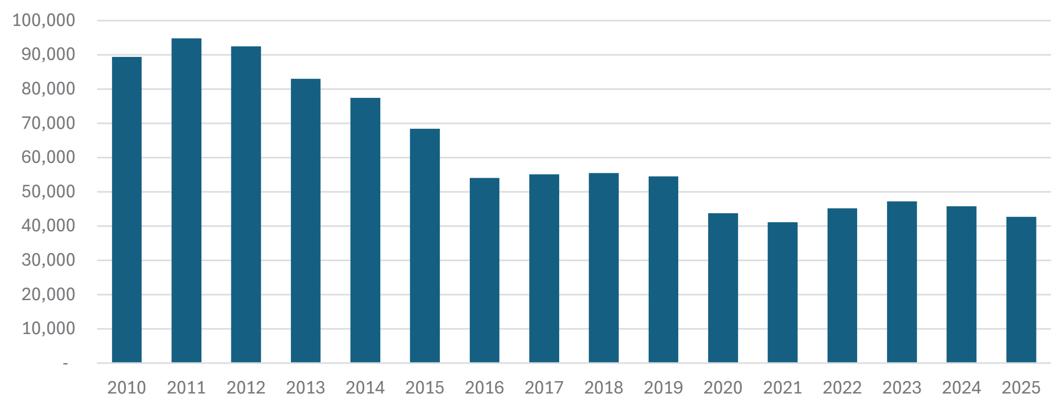


Source: Energy Ventures Analysis, Inc. | Note: Bonus PTC/ITC = $27.50/MWh & 30%; Max PTC/ITC = $33/MWh & 50%.

[29]Source: U.S. FERC Form-1 (https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-electric-utility-annual-report). and Lazard 2025 LCOE study (https://www.lazard.com/research-insights/levelized-cost-of-energyplus-lcoeplus).

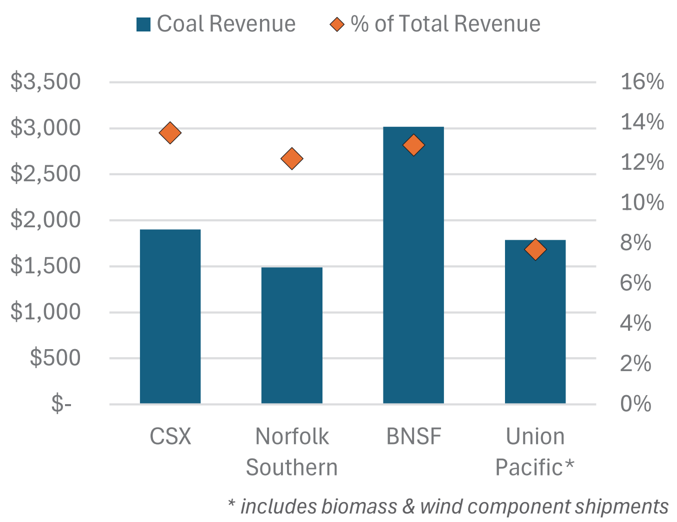
The coal supply chain is important to the national economy, especially in the 20 states that produce coal. Even with the decline in coal-fueled power generation, the country still has over 40,000 direct jobs in coal mining, with several times that number created by the associated economy.

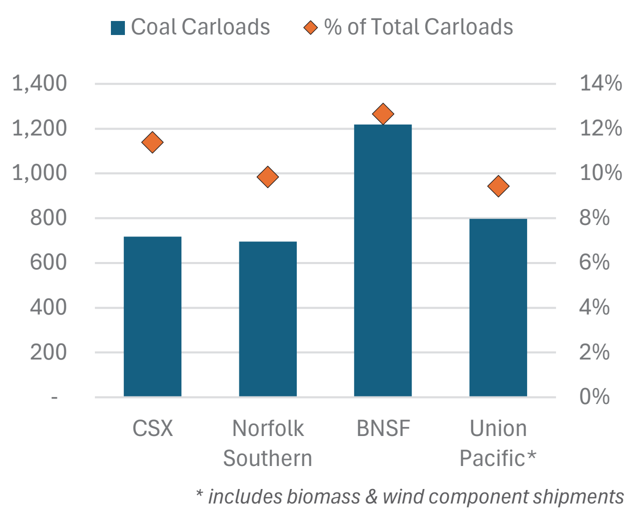
Figure 20 - U.S. Coal Mining Jobs[30]



The revenues from transporting coal support the national freight rail system, as coal is one of the most important products carried by the major freight railroads.

Figure 21 - 2025 Coal Revenues ($million – left) & Carloads (million – right) by Major U.S. Rail Carrier[31]





Over 40% of total U.S. coal production is mined on federal lands. In 2024, 209.5 million tons were produced from federal lands which generated federal revenues of $490 million in royalties and rents.[32] Coal produced from federal lands supplies over 50% of the coal purchased for power generation and is a critical source that could not be replaced from private lands.

[30]Source: U.S. MSHA (https://www.msha.gov/data-and-reports/mine-data-retrieval-system).
[31]Source: Railroad companies' 2025 SEC 10-K filings.
[32]Source: Office of Natural Resources Revenue https://revenuedata.onrr.gov.

Under the Obama and Biden administrations, the Bureau of Land Management (BLM) took action to block all new leasing of federal coal in Wyoming and Montana (the states that produce over 90% of federal coal), first by a moratorium in 2016, followed by a final rule in 2024. The suspension of federal coal leasing caused the available coal reserves in Wyoming to fall by half since 2013, as depletion from production was not replaced with new leases. If this rule had remained in place, coal supply for power generation would have started to decline by 2030, and existing leases would have been exhausted by 2041, effectively shutting off coal supply for over half the existing coal fleet. In 2025, the BLM ended the moratorium and revoked the federal ban on new coal leases.

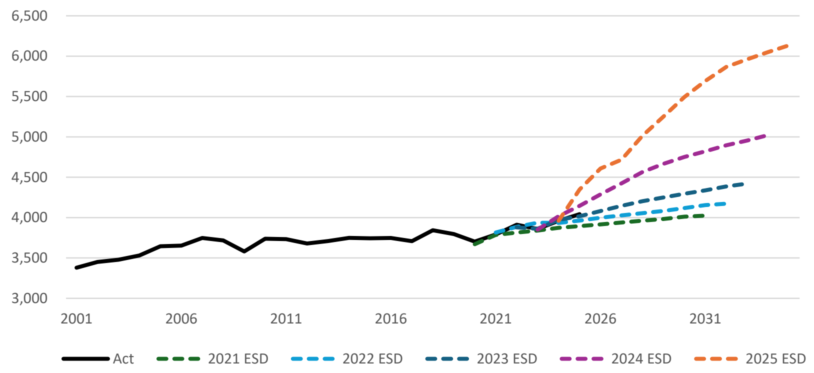
5. Electricity Demand Growth and Reliability

After nearly 15 years of stagnant electricity consumption, the United States has entered a new era of sustained and accelerating electricity demand growth. The financial crisis of 2008 – 2009, combined with aggressive energy efficiency programs across all sectors, effectively masked underlying growth in electricity use for more than a decade. Economic expansion, rising population, and increasing electrification were offset by efficiency gains, resulting in essentially flat national electricity consumption from 2007 through 2021 – a period that also enabled grid operators to absorb the closure of roughly one-third of the coal fleet without immediately triggering reliability warnings.

That era of stagnant electricity demand is over. Since the end of the COVID-19 pandemic, U.S. electricity demand has grown at over 1.6% per year, a rate not seen since the early 2000s. The primary catalyst has been explosive growth in data center electricity consumption, driven by the AI revolution's demand for ever-increasing computing power. AI-optimized data centers are extraordinarily energy intensive, and the pace of new facility construction has accelerated dramatically. This trend has fundamentally changed the reliability calculus for the U.S. electricity grid. Further, demand growth is being spurred by the push for electrification of homes and buildings, the shift to electric vehicles, and the reshoring of domestic manufacturing.

The magnitude of the demand surge has caught many forecasters flat-footed. NERC’s 2021 Electricity Supply and Demand (ESD) assessment projected just over 4,000 TWh of net energy for load by 2030 – a level that was already exceeded in 2025, five years ahead of that forecast. NERC's 2025 ESD has dramatically revised its projections upward, now projecting nearly 5,500 TWh of net energy for load by 2030 and over 6,100 TWh by 2035, representing increases of 36% and 52% over 2025 levels, respectively. The speed at which these forecasts have been revised – and exceeded – underscores just how quickly the demand environment has shifted.

Figure 22 - Lower-48 Net Energy for Load (TWh) - Actuals vs. NERC ESD Forecasts (right)[33]



Despite this urgent demand outlook, the nation's pipeline of new generating capacity is dominated by weather-dependent resources that cannot be counted on to meet peak demand reliably. According to Lawrence Berkeley National Laboratory, the U.S. interconnection queue held nearly 2,300 GW of proposed new capacity at the end of 2024, a staggering figure that might appear reassuring at first glance. However, only about 172 GW, or 7.5%, consists of conventional dispatchable generation capable of operating on demand regardless of wind speed or sunshine. More than one-third of the queued capacity is variable wind and solar without any battery or energy storage backup. Additionally, history shows that only about a quarter of projects entering the interconnection queue are ever actually built. In the meantime, their presence in the queue creates long delays for projects that will ultimately be built. There are no new coal power plant projects in the interconnection queue.[34]

The backlog problem is compounded by a dramatic lengthening of interconnection timelines. While a typical project once cleared the interconnection queue in less than two years, the average time from interconnection request to commercial operation had ballooned to over 54 months – more than 4.5 years – by 2024. New wind and solar projects face even longer waits as wind projects that entered the queue in the late 2010s and early 2020s now average nearly 5.5 years to reach commercial operation, and new solar projects average over four years, with co-located solar-plus-storage projects taking even longer. While the development timeline for new gas-fueled capacity was approximately three years, the surge of orders for new gas turbines and the limited availability of Engineering, Procurement, and Construction (EPC) contractors have caused the development time to increase to about seven years. The practical effect is that the addition of new reliable generation capable of meeting growing demand is being systemically delayed, even as the need becomes increasingly urgent.

These market conditions make the preservation of existing dispatchable capacity a near-term reliability necessity rather than merely an economic preference. While new resources will be needed over time, the current development pipeline is not capable of replacing retiring coal-fueled capacity quickly enough to meet rapidly increasing electricity demand. Existing coal power plants already have interconnection rights, transmission access, fuel supply logistics, operating workforces, and on-site infrastructure in place. Preserving and modernizing these assets can therefore provide reliable capacity materially faster than relying solely on new generation additions that must overcome interconnection delays, permitting challenges, equipment backlogs, fuel infrastructure constraints,

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[33]Source: 2025 NERC Electricity Supply & Demand (ESD) Assessment (https://www.nerc.com/programs/reliability-assessment--performance-analysis/electricity-supply--demand).
[34]Source: https://emp.lbl.gov/publications/queued-2025-edition-characteristics.

and financing risk. Market and regulatory reforms should recognize this timing value by prioritizing retention of existing dispatchable resources while the new-build pipeline catches up to demand growth.

Figure 23 - Active Interconnection Requests by Fuel Type (GW - left) & Number of Requests by Status (2000-2019 – right)[35]

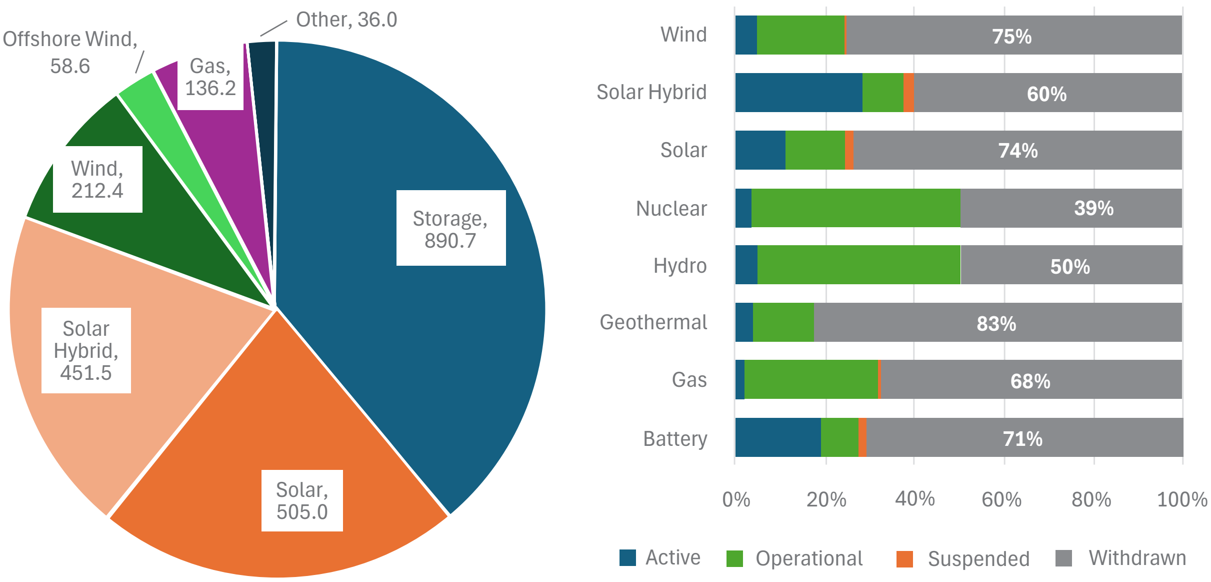
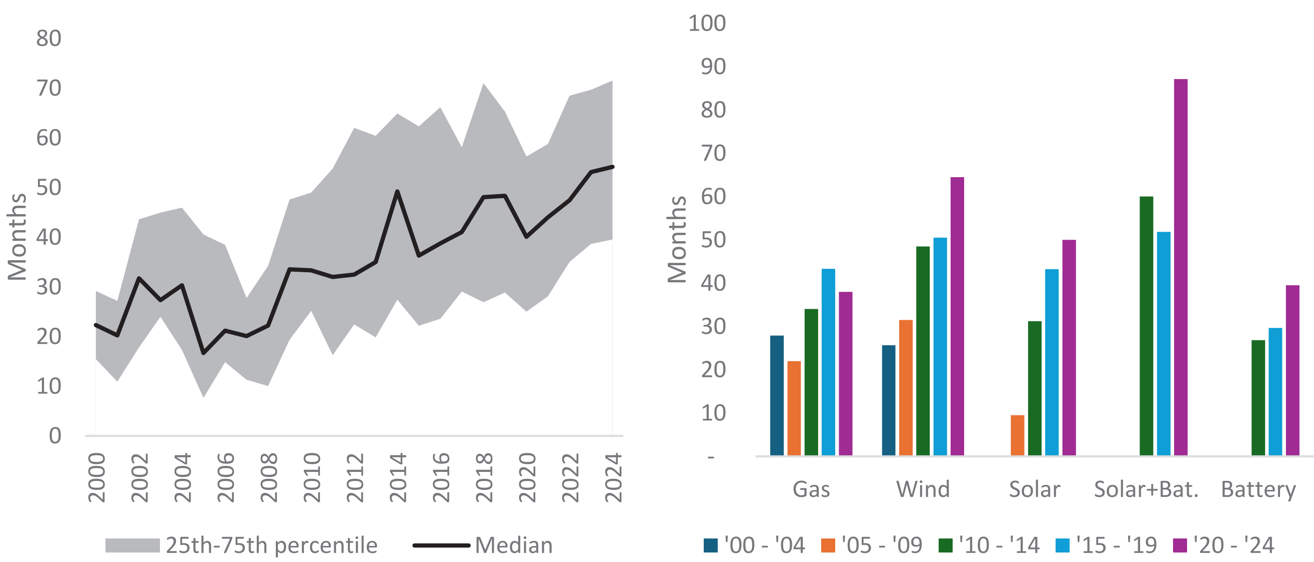


Figure 24 - Number of Months from Interconnection Request to Commercial Operation Date – All Fuel Types (left) and by Fuel Type (right)[36]

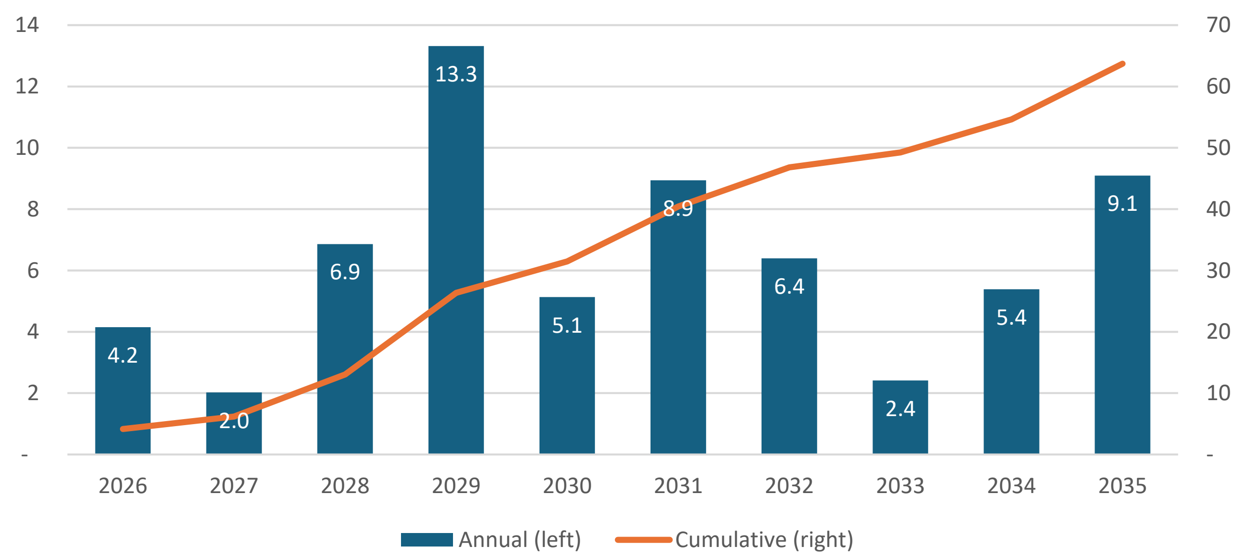


[35]Data as of the end of 2024; Source: Lawrence Berkeley National Laboratory (https://emp.lbl.gov/queues).
[36]Source: Lawrence Berkeley National Laboratory (https://emp.lbl.gov/queues).

Compared to large central station conventional power plants, the small size of wind and solar projects and their location in remote areas place a much greater burden on the interconnection and transmission infrastructure required to integrate these resources into the grid. Onshore wind projects are located far from populated areas (the better wind resources are not close to population centers) and require major investment in long-distance high-voltage transmission lines to deliver this power to the demand centers. Offshore wind projects face even more daunting challenges.

Compounding the supply-side constraints is the continuing attrition of the coal fleet. Over 60 GW of coal-fired capacity are still scheduled to retire over the next decade due in part to compliance deadlines embedded in federal environmental regulations – rules finalized by the Obama and Biden administrations with the explicit intent of forcing coal power plant closures. More than 26 GW are scheduled to retire before 2030, including over 13 GW in 2029 alone. These retirement mandates do not make sense at a time of rapidly increasing electricity demand.

Figure 25 - Planned Coal Retirements (GW)[37]

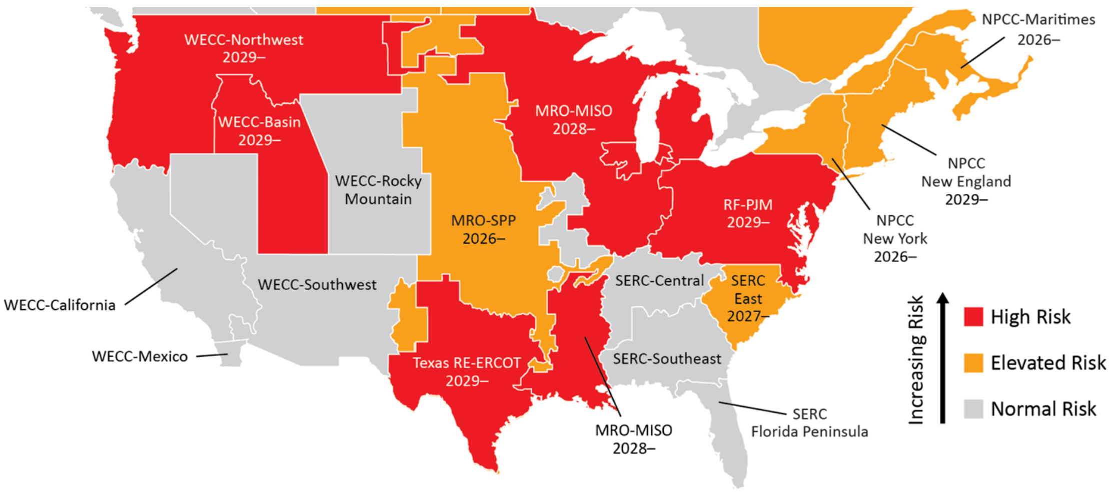


[37]Excludes coal-to-natural gas conversions; Source: EIA 860 data and company announcements.
[38]https://www.nerc.com/our-work/assessments.

The combination of surging electricity demand, a clogged interconnection queue dominated by unreliable intermittent resources, and the continued retirement of proven dispatchable generation has prompted urgent warnings from the nation's most authoritative grid reliability organizations – NERC, DOE, and a number of grid operators.

NERC's 2025 Long-Term Reliability Assessment (LTRA)[38], released in January 2026, paints a troubling picture of the decade ahead. The report – NERC's annual ten-year snapshot of North American grid adequacy – found that 13 of 23 assessment areas across North America now face "elevated" or "high" resource adequacy risks over the next five years. NERC projects that summer peak demand across the continent could surge by as much as 224 GW over the assessment period, a figure 69% higher than the prior year's LTRA had projected – and that winter demand could grow by an even larger 245 GW, a 65% upward revision. These are not incremental adjustments; they reflect a wholesale reassessment of the scale and speed of the demand challenge. NERC identified the interconnection queue's unreliability as a central concern: few projects advance through the approval process, and development is threatened by supply chain bottlenecks and interconnection delays. Meanwhile, NERC expects existing fossil-fueled capacity to decline over the next decade, while the additions from batteries, solar, and wind – despite their rapid growth – do not provide the firm, dispatchable power that a reliable grid requires, and they have an increasing waste management problem. NERC specifically flagged the grid's growing dependence on natural gas as introducing new fuel-assurance vulnerabilities, particularly during extreme cold weather events when residential heating demand competes directly with power plants for gas supply. NERC's key recommendations – streamlining system growth processes, carefully managing generator retirements, conducting robust regional adequacy assessments, and better coordination of electric and natural gas infrastructure planning – all point toward the same conclusion that coal retirements must stop, and planned retirements must be reversed.

Figure 26 - NERC 2025 LTRA - Risk Area Summary - 2026-2030[39]

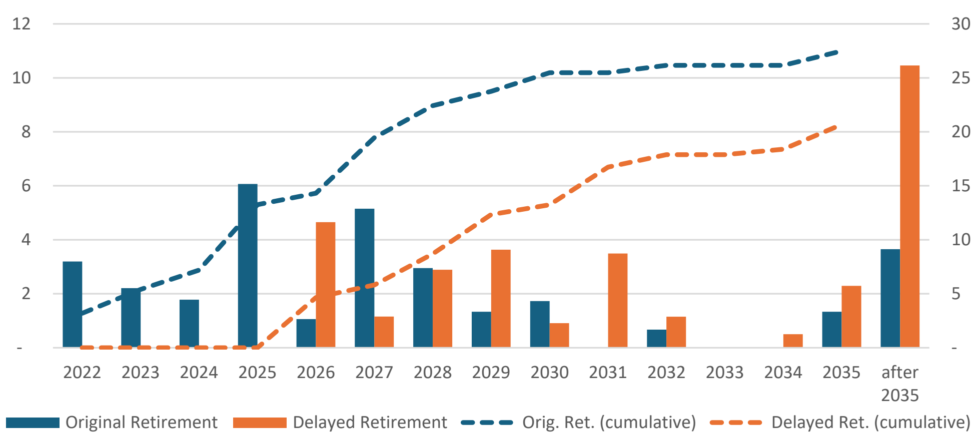


[39]Source: https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.
[40]https://www.energy.gov/topics/reliability.

DOE reached equally alarming conclusions in its July 7, 2025, report, "Evaluating U.S. Grid Reliability and Security,"[40] released pursuant to President Trump's Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." Using a deterministic simulation model that evaluated grid performance across all 8,760 hours of the year under 12 historical weather scenarios and across 23 planning regions, DOE assessed the grid's ability to meet projected demand through 2030. The findings are stark. Under the "current system" baseline (2024 conditions), the grid performs acceptably with an estimated 8.1 annual loss-of-load hours. However, under DOE's "Plant Closures" scenario – which incorporates the 104 GW of announced retirements scheduled through 2030, approximately three-quarters of which are coal, loss-of-load hours balloon to 817 per year, a hundredfold increase. DOE projects that electricity demand will grow by roughly 101 GW, or 15%, by 2030, driven by approximately 50 GW of AI and data center load and 51 GW of other new loads. Against this backdrop, only 22 GW of new firm dispatchable capacity – natural gas and nuclear – are expected to be added. The report specifically identified PJM and ERCOT as the regions facing the highest reliability risks, each requiring approximately 10.5 GW of new firm capacity to maintain acceptable reliability standards. DOE's findings directly informed its deployment of emergency authority under Section 202(c) of the Federal Power Act to prevent premature coal power plant closures and make clear that allowing coal retirements to continue without a credible replacement strategy would be harmful to the reliability and security of the nation's electricity grid.

Some coal power plant owners have responded to these warning signals by delaying or reversing planned retirements. DOE's Section 202(c) emergency orders have so far preserved over 3.3 GW of coal-fueled capacity that would otherwise have retired. Taken together, DOE orders and voluntary retirement delays have preserved more than 13 GW of coal capacity that would have closed by now absent intervention – a meaningful contribution to grid reliability. However, these individual actions are no substitute for a comprehensive policy framework that extends coal operations for as long as the grid requires. Many delayed retirements face a hard stop at the end of 2028 imposed by the 2020 ELG rule's retirement subcategory provision. Some plant owners have responded by investing in full ELG compliance to enable operations beyond 2028, with nearly 7 GW of previously planned retirements now delayed well into the next decade. These investments in compliance and continued operation represent exactly the kind of rational, reliability-preserving response that federal policy should be designed to encourage and reward, not penalize.

Figure 27 - Coal Plant Retirement Delays (GW)[42]



[41]https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.
[42]Source: Various company announcements and updated Integrated Resource Plans.

6. Preserving, Modernizing and Optimizing the Coal Fleet

Opponents of coal regularly describe the coal fleet as "aging," but the age of a coal power plant does not affect its ability to continue operating for decades to come. With proper reinvestment, coal power plants can continue to operate efficiently and economically far beyond their initial planned life.

The oldest coal power plants in the country still operate efficiently and economically. For example, utilities built four large coal power plants from 1953 to 1956 to supply the Atomic Energy Commission's uranium enrichment plants at Portsmouth, Ohio, Paducah, Kentucky, and Oak Ridge, Tennessee. Utilities built the Kyger Creek (963 MW in Ohio), Clifty Creek (1,173 MW in Indiana), Shawnee (1,071 MW in Kentucky), and Kingston (1,298 MW in Tennessee) plants to supply reliable power around the clock. These plants are all over 70 years old and operate economically today (one of the ten units at Shawnee was closed after being repowered with a different experimental technology). In 2025, three of these four plants ran at a higher capacity factor than the national average (Clifty Creek – 55%, Kyger Creek – 60%, Shawnee – 68%) with heat rates similar to the national average of 10,964 Btu/kWh (Clifty Creek – 10,843 Btu/kWh, Kyger Creek – 10,756 Btu/kWh, Shawnee – 10,950 Btu/kWh). These plants have air pollutant emission rates for SO_2 and NO_x similar to the low national averages (0.17 and 0.13 lb/MMBtu, respectively) because they have optimized operations and invested in modern emissions controls. The owners of the Kyger Creek and Clifty Creek plants have signed contracts committing to keep these plants operating until at least 2040, while TVA has recently proposed to continue operating the Shawnee and Kingston plants until 2039.

Federal actions are necessary to preserve and modernize the coal fleet. These actions include changes to laws, regulations, policies, and programs. The Trump administration has already initiated many changes, but other changes are necessary to preserve the remaining coal fleet and to enable the construction of new coal power plants. The following are recommendations that are intended to preserve the remaining coal fleet and help assure a healthy coal supply chain.

Environmental Regulations

EPA rules are the most significant regulatory uncertainty facing the coal fleet. The nation's coal fleet is subject to many EPA regulations developed primarily under provisions of the Clean Air Act (CAA), Resource Conservation and Recovery Act (RCRA), and Clean Water Act (CWA). These regulations have become increasingly stringent over time, resulting in substantial compliance costs and causing or contributing to a large number of coal retirements. To make matters worse, the regulations have caused considerable compliance and planning uncertainty as EPA has developed regulations to achieve the policy objectives of each new administration that often conflict with the objectives of prior administrations. Collectively, seven of the regulations below have undergone major revisions at least 20 times over the past 15 years, demonstrating the unpredictable planning environment in which the coal fleet operates. Continuous litigation over the legality of these regulations has also caused uncertainty. This regulatory uncertainty has become a major problem for the power sector because it must make multi-billion-dollar investments in long-lived assets at the same time the grid is undergoing transformation.

Fortunately, EPA is in the process of repealing or revising major regulations that impact the coal fleet and, in many instances, taking an approach that promises to provide more long-term legal durability than prior reform efforts. Many of EPA's rulemakings, so far, are consistent with the recommendations below. However, completing the rulemakings in a timely manner has proved to be challenging because of the substantial effort involved in reconsidering a large number of major rules. EPA should continue its work to repeal or rewrite these rules as soon as possible in order to defend them in court while the current administration is in office. The discussion below highlights regulations and policies the NCC believes are the highest priority for the coal fleet.

Carbon

Carbon regulations have the greatest impact on the existing coal fleet, and they are a major impediment to building new coal power plants. EPA is in the process of repealing Carbon Pollution Standards promulgated by the Biden administration for existing coal power plants, the Endangerment Finding that justifies regulating GHG emissions from existing fossil-fuel power plants under Section 111(d) of the CAA, and New Source Performance Standards for new coal power plants under Section 111(b). We urge the agency to complete these critically important repeal efforts as quickly as possible. In addition, we urge Congress to codify the regulatory changes that EPA is expected to finalize.

New Source Review

The NSR program requires major stationary sources of air pollution to obtain permits before modifying an existing facility or prior to beginning construction of a new facility. Over the last 30 years, EPA has adopted conflicting changes to its NSR regulations through both regulations and guidance. The last major attempt to reform NSR for the power sector by rulemaking occurred in 2018 when EPA proposed revisions to the NSR program as part of the Affordable Clean Energy rulemaking. However, the agency did not finalize the proposal. NSR reforms are necessary to remove regulatory obstacles that could prevent coal power plants from undertaking major maintenance and refurbishment projects necessary for efficient and reliable operation and to satisfy the rapidly increasing growth in electricity demand. Since last year, EPA has undertaken NSR reforms, but those reforms do not sufficiently address the concerns with power plant maintenance and refurbishment projects. We urge EPA to make such changes to its NSR regulations as soon as reasonably possible. In addition, we urge Congress to codify these changes.

[43] Source: Annual EIA-923 data (https://www.eia.gov/electricity/data/eia923).

Effluent Limitations Guidelines

The CWA requires EPA to establish limits governing the discharge of effluents and to periodically update guidelines that environmental officials must follow in setting those limits. In 2024, EPA issued a revised ELG rule that sets zero liquid discharge limits for flue gas desulfurization wastewater, combustion residual leachate, and bottom ash transport water from coal power plants. The 2024 rule is the third time EPA has revised the effluent limitations for coal power plants within the last ten years. Previous ELG rules were issued in 2015 and 2020.

The 2024 rule is based on technologies that are exorbitantly expensive and not adequately demonstrated (see "Standards Setting" below). The rule also includes an explicit incentive for coal power plants to retire prematurely, which is nonsensical in light of the need for coal power plants as a source of reliable electricity. In late 2025, EPA published a rule to extend compliance deadlines and provide compliance flexibility under both the 2020 and 2024 rules. However, making changes to the 2024 rule is not sufficient to remedy its flaws. Instead, we urge EPA to repeal the 2024 rule as soon as possible.

Coal Combustion Residuals

Coal combustion residuals (CCR) are produced as a result of burning coal in coal power plants. EPA issued regulations for the management and disposal of CCR in 2015, 2018, 2019, 2020, and 2024. EPA now has underway several rulemakings to reconsider many CCR requirements. For example, EPA has proposed changes to the requirements for managing and selling CCR byproducts, closing CCR management units, and changes that enable states to establish alternative risk-based requirements. Although these proposed changes are generally an improvement over current requirements, additional reforms are still necessary regarding compliance deadlines and site-specific performance standards. Also, EPA should make additional revisions that further encourage beneficial use of CCR byproducts in construction (fly ash in cement and gypsum in wallboard), as feedstock for critical minerals, and other purposes.

Ozone Transport Rule

The CAA requires states to reduce emissions that "significantly contribute" to the exceedance of a national ambient air quality standard in another state. After setting a more stringent standard for ozone in 2015, EPA determined that 23 states should develop state implementation plans to reduce NO_x emissions. EPA issued an Ozone Transport Rule in 2023 that established federal implementation plans imposing stringent NO_x control requirements for coal power plants located in these states. (EPA later determined that five more states should be subject to the rule.) Several states challenged the rule, and the Supreme Court stayed its implementation. EPA currently has underway a two-phase rulemaking to reconsider the program. The first phase involves EPA reversing the disapproval of state plans. The second involves making broader changes to the program. The first-phase approvals foreshadow structural changes that EPA is expected to make to the rule itself in phase two. We look forward to these expected changes and to the continued approval of state plan revisions.

Mercury and Air Toxics Standards

MATS regulate hazardous air pollutant emissions from coal power plants. EPA adopted the first standards for coal power plants in 2012. The CAA requires EPA to review these standards periodically to determine whether they should be revised based on a "residual risk review" and a "technology review." A flawed technology review was the basis for the stringent 2024 revisions to the original MATS rule and, therefore, the agency repealed the 2024 rule. The repeal rule is currently the subject of litigation. We commend EPA for repealing the 2024 Rule.

Regional Haze

EPA promulgated the Regional Haze Rule in 1999 that directs states to adopt plans to improve visibility in national parks. These state plans sometimes require more stringent controls for SO_2 and NO_x. Under the current rule, states must work toward a long-term goal of returning national parks to their natural visibility conditions by 2064. To assure states are making reasonable progress towards the goal, regional haze regulations require states to adopt plans establishing control measures for power plants and other major sources of emissions that are impairing visibility. In the case of states that fail to adopt adequate regional haze plans, EPA has the authority to impose federal implementation plans on each state. Recently, EPA has begun reversing its prior disapprovals of state plans. In addition, the agency is expected to initiate a rulemaking that will lead to broader reforms of the regional haze program. We also applaud EPA's recent rejection of state regional haze plans that call for premature coal power plant retirements.

Standards Setting

Certain environmental statutes require standards to be "economically achievable" and based on "adequately demonstrated" technology. Statutes that use these terms as the basis for setting standards include the CAA and the CWA. For example, EPA erroneously determined that CCS is adequately demonstrated and economically achievable when it issued the 2024 Biden Carbon Pollution Standards. Similarly, EPA determined that zero liquid discharge technologies are adequately demonstrated and economically achievable, even though they are neither, when the agency revised its ELG rule in 2024. "Adequately demonstrated" and "economically achievable" are important terms that are the basis for highly consequential regulations, but both terms lack well-defined criteria. We recommend that EPA issue guidance that provides a clear explanation of both terms.

Cost-Benefit Analysis

Cost-benefit analysis is important because it influences regulatory decisions. For that reason, EPA has begun reforming its cost-benefit methodology. In particular, the agency will continue to estimate the costs and other impacts ("disbenefits") of regulations on industry and the reduction in emissions ("benefits") that would result from those regulations. However, EPA will no longer monetize the health benefits associated with emission reductions because there is too much uncertainty in the health benefits estimates. We commend and support EPA for reforming its cost-benefit methodology.

EPA's 2012 MATS rule is a good example of the need to reform cost-benefit analysis. The purpose of the rule was to reduce emissions of mercury and other hazardous air pollutants (HAPs). The monetized health benefits of reducing HAPs were estimated by EPA to be only $4-6 million per year, compared to a cost of $9.6 billion. However, EPA estimated the monetized benefits of the rule would be $33-90 billion per year by including co-benefits from reducing fine particles and SO_2. (In addition, EPA assumed that some of these health benefits were occurring in attainment areas already meeting the national ambient air standards.) The MATS rule would have failed by a wide margin to pass a cost-benefit test if EPA had not monetized co-benefit emission reductions.

Reliability Impacts

We urge EPA to collaborate closely with FERC, NERC, and grid operators to analyze the impacts of rules on grid reliability and resource adequacy. EPA uses the Integrated Planning Model to estimate the impact of environmental policies on the electric power sector. However, the model does not properly analyze the reliability impact of policies, and past agency practice has not properly reflected the input of state, regional, or federal officials with grid reliability responsibilities.

Regulatory Certainty

Regulatory certainty is essential to efficient planning and investments. Durable certainty would allow power plant owners, grid operators, and investors to make long-term decisions based on reliability needs and financial considerations rather than attempting to comply with constantly changing regulations. While changes to current regulations are critical to preserving and modernizing the coal fleet, a future administration could modify these regulations once again to force coal retirements and add roadblocks to the construction of new coal power plants. Codification by Congress of the changes being made to regulations by EPA would provide certainty, and we urge Congress to pursue codification.

Department of Energy
Department of the Interior
Federal Energy Regulatory Commission
Department of War

Besides DOE, FERC also has a major role to play in preserving and modernizing the coal fleet. DOE focuses on policy-making and long-term energy planning, and FERC functions as a regulatory body that, among other things, oversees six of the nation's seven regional transmission organizations (RTOs). Together, these six RTOs have more than 110,000 MW of coal-fueled generation, or almost two-thirds of the U.S. coal fleet. However, present RTO market mechanisms produce outcomes that impair grid reliability, insufficiently value on-site fuel and other coal power plant attributes, disadvantage coal-fueled power generation, and raise power prices unnecessarily. The following recommendations build on the initiatives the Trump administration has already undertaken to support the coal fleet and its supply chain. It is important to emphasize that these recommendations, as helpful as they are, are likely to be insufficient to prevent more coal retirements if EPA regulations become aggressive in the future. Because of the significant impact of EPA rules on energy policy, we recommend that DOE enhance its environmental policy expertise to support EPA's efforts to change its rules.

Financial Support

So far, DOE has awarded more than $1 billion in grants to support the coal fleet, as well as loans.[44] The ideal level of funding that might be needed to support coal projects is uncertain, but the potential need could exceed the amount set aside for grants and loan guarantees. For example, $50 million has been allocated for wastewater treatment facilities at coal power plants. However, the cost to install these treatment systems for just a single coal power plant can be $100 million to $200 million, and emission controls for a single plant can cost even more. Moreover, total capital spending to support projects to maintain or improve the performance of the coal fleet could exceed $1 billion per year. Also, the process for applying for, evaluating, and awarding financial support should be streamlined and provide maximum flexibility for combining federal financial support. Last, it is critical that NSR regulations be modified to clarify that projects, such as those funded by DOE, to refurbish and modernize coal power plants will not trigger NSR.

Government intervention to preserve existing generation assets is not unprecedented. Federal and state programs have provided financial support to merchant nuclear facilities when policymakers concluded that market revenues alone were insufficient to preserve resources providing reliability, fuel diversity, and energy security benefits. Existing coal power plants can provide many of these same attributes, particularly on-site fuel storage, operational flexibility, and dependable capacity during periods of system stress. Accordingly, federal funding programs should provide comparable opportunities for coal power plants that demonstrate ongoing reliability value.

Across the United States, electricity markets are forecast to operate at very thin reserve margins due to increasing retirements and upward pressure due to demand growth from data centers. Therefore, dispatchable and reliable capacity with high accreditation is needed to meet the growing demand and prolonged periods of grid emergency performance such as during winter storms.

Large Loads, Bilateral Contracts, and Co-location

The administration should incent bilateral contracts between large loads and existing coal power plants. This recognizes that increases in net generation will only occur if existing generation is preserved, not merely replaced with new generation. Proposals that encourage loads to contract with only new resources will add pressure for existing resources to retire. Incentives should be offered to large loads that contract with existing resources, especially those that would otherwise retire. For example, new large loads that enter into contracts with existing coal power plants should be made eligible for fast-track interconnection treatment. They could also be offered other streamlined benefits if they locate on federal lands and enter into agreements to purchase power from existing coal power plants. [45]

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[44] See https://www.energy.gov/hgeo/funding-notice-restoring-reliability-coal-recommissioning-and-modernization.

Many existing coal generating facilities operate at substantially lower utilization levels than in prior years, leaving both generation and transmission infrastructure underutilized. Co-location policies should prioritize the use of existing interconnection capacity and transmission infrastructure before requiring new investments. Consistent with FERC's recent large-load integration reforms, including flexible transmission service, dynamic line ratings, and power-flow control technologies, priority should be given to projects that increase utilization of existing dispatchable resources, particularly large coal power plants with underutilized capacity and established grid connections. Such approaches can accelerate load interconnections, lower infrastructure costs, preserve reliability, and improve utilization of existing coal-fueled generation.

Federal large-load interconnection policy should distinguish between projects that merely shift load behind the meter and projects that increase net reliable supply by preserving existing dispatchable generation. Co-location arrangements involving existing coal power plants should be eligible for expedited treatment where the large load enters into a long-term contract that supports continued operation of the plant, demonstrates that the arrangement will not degrade grid reliability, and remains responsible for appropriate transmission costs associated with any incremental grid use. This approach would align large-load growth with resource adequacy needs by encouraging data centers and other major electricity users to support existing dependable capacity rather than relying exclusively on new resources that may not be available for several years. In addition, large-load interconnection policies should include mechanisms that improve the accuracy of load forecasts since accurate projections are critical to avoid over- or underinvesting in generating resources and grid infrastructure.

Price Distortions

Wholesale electricity prices in regions such as MISO and PJM increasingly fail to reflect the full cost of retaining dispatchable, fuel-secure generation. Out-of-market subsidies – federal PTC and ITC, state RPS and CES, and dedicated zero-emission credit programs for nuclear generation – enable subsidized resources to offer electricity into wholesale markets at artificially low or even negative prices. These suppressed price signals distort competition, reduce revenues for dispatchable resources, and accelerate the premature retirement of coal power plants. Federal wholesale market reforms are necessary to eliminate these distortions and restore accurate price formation. FERC should direct grid operators to require generators to offer power at the true cost of generation, excluding subsidies, and to reflect fixed fuel supply commitments in dispatch policies.

DOE should conduct a comprehensive analysis of the impact of out-of-market subsidies on wholesale price formation, the cost allocation discrepancies that result from state-level mandates affecting regional grid reliability, and the reliability implications of subsidy-driven price suppression. Building on that analysis, FERC should evaluate, through proceedings under Section 206 of the Federal Power Act, whether the wholesale rates under current market design remain just and reasonable in light of subsidy-driven price suppression and, where the record supports such a finding, direct organized markets to adopt a technology-neutral offer floor, that is, a minimum offer price rule that benchmarks bids against the underlying cost of producing reliable capacity and energy after accounting for the value of out-of-

[45] See comments by America's Power to FERC Docket No. RM26-4-000, Interconnection of Large Loads to the Interstate Transmission System.

market subsidies. Subsidized resources would remain eligible to participate in the market but would no longer be able to suppress clearing prices below the true cost of maintaining reliability.

Price formation reforms should also address the missing revenues associated with reliability services that are not fully captured in energy or capacity market clearing prices. Fuel assurance, operating endurance, dispatchability, voltage support, ramping capability, minimum-load operation, and the ability to sustain output during multi-day reliability events all provide system value, but many organized markets do not explicitly compensate these attributes. As a result, markets may appear to be clearing at competitive prices while still failing to provide sufficient revenue to retain the resources needed during periods of system stress. A durable market reform framework should therefore combine technology-neutral mitigation of subsidized offers with affirmative compensation for measurable reliability attributes.

Effective Load Carrying Capability

ELCC is the methodology grid operators use to measure how much reliable generating capacity a resource can provide during times when the grid is under the most stress. ELCC helps ensure that a sufficient amount of reliable generating capacity is available to meet reserve margins.

Grid operators should evaluate whether existing accreditation methodologies adequately recognize resources capable of continuous operation over multi-day or multi-week reliability events without dependence on real-time fuel delivery or recharging. Coal power plants that maintain substantial on-site fuel inventories can sustain operations during fuel supply disruptions, pipeline constraints, extreme weather events, and other emergency conditions. As demonstrated during Winter Storm Elliott, approximately 70% of generation outages in PJM were associated with natural gas-fueled units, while coal units accounted for only 16% of outages, highlighting the reliability value of substantial on-site fuel inventories. As resource adequacy concerns shift from meeting peak demand during a limited number of hours to maintaining reliability throughout extended stress events, accreditation frameworks should place greater weight on operating endurance, fuel assurance, and sustained availability.

Accordingly, resources that demonstrate sustained operating capability and fuel assurance during extended reliability events should receive additional accreditation value or compensation reflecting their contribution to system resilience. Such accreditation frameworks should recognize both the ability to perform during critical reliability hours and the ability to continue operating throughout multi-day reliability events, thereby appropriately valuing investments that enhance fuel security, dispatchability, and operational endurance.

Reliability Attributes

Electricity markets do not explicitly value all reliability attributes, especially fuel security. FERC should direct grid operators to identify all reliability attributes and ensure that these attributes are properly valued in capacity and energy markets. Consistent with these goals, FERC should ensure that dispatchable power plants, such as coal power plants, are compensated for operating at minimum load to maintain reliability.

Reliability Must Run

DOE has issued emergency orders under Section 202(c) of the Federal Power Act to keep units operating at five coal power plants. Although helpful, these orders are likely to be in effect for only 90 days at a time. RMR agreements have been used by grid operators to keep plants operating for longer periods of time until reliability problems can be resolved, for example, by adding transmission. FERC should direct grid operators to expand the scope of RMR agreements to keep plants operating in order to maintain longer-term resource adequacy, not just transmission security.

The need for RMR agreements often reflects a broader market failure to adequately compensate resources that provide reliability, fuel security, and resilience benefits. If market reforms appropriately value these attributes through capacity accreditation, fuel security compensation, and other reliability mechanisms, many coal power plants that are currently at risk of retirement could remain economically viable without requiring out-of-market RMR support. RMR agreements should therefore serve as a temporary backstop rather than the primary mechanism for preserving resources needed to maintain reliability.

Agreements that Force Retirements

We estimate that the owners of 26 coal-fueled generating units totaling almost 16 GW have entered into settlement agreements to either retire or stop burning coal. DOE should work with states and grid operators to identify the coal power plants with such agreements and whose retirement might pose threats to reliability. Once these plants are identified, DOE should work with plant owners, state authorities, and others to void or modify the agreements.

Preferential Treatment

Some grid operators provide advanced commitment to dispatch natural gas power plants to compensate for the fact that, unlike coal, most gas power plants do not have on-site fuel storage or firm fuel contracts. Advanced commitment for dispatch allows these plants to purchase gas in advance and sell the power to the grid even when uneconomic. This forced burn causes unfair harm to coal power generation, which is forced to reduce dispatch despite having lower costs and providing the security of on-site fuel. Such actions distort dispatch and should be eliminated. Gas power plants should have on-site fuel storage (oil or LNG) or enter into firm fuel contracts, and when they do not, they should not displace resources that do.

Coal for Specific Plants

Many coal power plants were developed based on a specific coal source, especially mine-mouth power plants in the Western U.S. For that reason, these plants cannot economically change coal supplies to alternative sources. DOE should identify coal power plants that depend on a specific coal source and coordinate with DOI (including its bureaus that regulate coal mining) to develop a plan to ensure that these coal sources receive coal leases, mine plan approvals, and reclamation permits needed to supply the plants.

Supply Chain for Manufacturers

The Defense Production Act (DPA) should be used to provide financial support to domestic manufacturers of boilers and parts used in coal power plants. The decline in construction of new coal power plants has reduced the availability of parts and supplies to maintain existing plants. As part of the program to reshore critical manufacturing capacity, the administration should include coal plant and electric grid manufacturing capability.

National Historic Preservation Act

The National Historic Preservation Act (NHPA) requires federal agencies to consider effects on historic properties before federal undertakings proceed by requiring a "reasonable and good faith effort" to identify historic properties. In practice, this review has become a significant source of cost and delay for coal infrastructure projects. DOI and the Advisory Council on Historic Preservation (ACHP) should negotiate a national Programmatic Agreement for energy infrastructure, modeled on the existing Federal Highway Administration agreement for highway undertakings, and ACHP should issue a categorical exemption for scientific and geological sampling. DOI should proceed with rulemaking to define "ground disturbance" with materiality thresholds below which archaeological review is not triggered. These reforms would shorten permitting timelines for coal infrastructure projects without weakening historic preservation.

Department of War

DOW intends to procure power from coal-fueled generators for national security purposes. In support of this effort, the Defense Logistics Agency (DLA) Energy has issued a request for proposals related to the award of contracts for long-term power purchase agreements with coal-fueled generators to provide electricity to DOW facilities. DLA Energy should consider providing a minimum guarantee to contractors to ensure that electricity providers are positioned to respond to future procurements, as well as additional information regarding how the program will be operationalized at the task order level. Also, DOW should evaluate the potential for reopening idled coal-fueled combined heat and power plants at domestic military bases.

New Coal Power Plants

It is not enough simply to save the existing coal fleet from retirement. Government agencies, led by DOE, should support the development of new coal power plants to serve the growing demand for electricity. New coal power plants use the latest modern technologies for power generation and emissions controls, providing increased efficiency and minimizing environmental impacts. More than 370 GW of high efficiency, low emissions coal-fueled generation are under development in other countries. Development of new coal power plants in the United States would support the boiler manufacturing industry, preserving the skills, equipment, and parts needed to maintain the remaining coal fleet. New coal power plants that are under development in Asia use boilers designed and supported primarily by manufacturers in Japan, South Korea, and China. It is important for the United States to maintain the capability to design and build new coal power plants to support a strategy of energy security.

- DOE should assess the roadblocks to new coal power plant development and provide recommendations for changes to regulations, legislation, and policies needed to eliminate these roadblocks.
- DOE should establish a multi-winner grant program using DOE's nuclear[46] and CCS demonstration[47] competitions as models. The recommended structure is a first solicitation funding several projects at the FEED and early development stage, with follow-on solicitations that lead to deployment.
- DOE should treat repowering at existing and recently retired coal power plant sites as a new coal power plant. Replacing boiler islands, steam cycles, or full units at existing or recently retired coal power plants is technically new construction, but it uses the existing transmission interconnection, water rights, fuel logistics, operating permits, and workforce.
- DOE should designate a specific amount of loan guarantee authority for new coal power plants within the Energy Dominance Financing Program.
- FERC should provide expedited queue treatment for new coal power plants.

7. Epilogue

Coal is our nation's most abundant, reliable, and secure electricity resource. The Trump administration realizes the importance of the coal fleet and a healthy supply chain and has taken many steps to support coal. At the same time, additional steps are necessary to maximize the value of the coal fleet.

EPA must complete the **regulatory reforms** already underway as quickly as possible. In particular, finalizing the repeal of the Carbon Pollution Standards and the Endangerment Finding, repealing the 2024 ELG Rule, and completing NSR reforms are essential to sustaining a healthy coal fleet. Congress should codify these reforms to provide durable certainty.

Wholesale electricity markets must be reformed. A technology-neutral price floor, properly valued reliability attributes, and accreditation values that reflect performance during system stress will help restore price signals that are necessary for sound investment decisions. FERC, in Section 206 proceedings, should evaluate whether current market outcomes are just and reasonable and, where the record supports such a finding, direct the adoption of reforms in organized electricity markets.

Financial support, supply chain protection, and coal leasing certainty must be sustained, alongside coordinated state-level regulatory action and dedicated DOE funding to support refurbishment and modernization of existing coal power plants.

Together, these recommendations from the National Coal Council represent a strategy for sustaining the nation's coal fleet and its supply chain.

[46] See https://www.energy.gov/ne/generation-iii-small-modular-reactor-program.
[47] See https://www.energy.gov/oced/CCdemos.

8. Exhibit

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