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The Economics of Coal-Fired Generation:

An Assessment of Ratepayer Risk

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Abstract

Surging electricity demand and a series of federal interventions to delay coal plant retirements have reshaped the terms of the national energy debate. A renewed interest in prolonging the operation of aging coal-fired generating units has surfaced – framed by some policymakers and grid operators as a necessary response to load forecasts, reliability imperatives, and constrained capacity margins. This framing deserves rigorous scrutiny. A synthetic review of recent analyses suggests that the economic case for coal retirement has not weakened as demand has risen. Indeed, the structural cost disadvantages of aging coal assets have deepened, and skipping past a careful economic analysis runs the risk of passing high costs onto ratepayers in coal-dependent jurisdictions.

This paper synthesizes recent analyses and draws on publicly available utility filings, market data, and cost benchmarks to examine the economic fundamentals underlying current coal performance at the national level and in select states. The state-level analysis covers five jurisdictions with significant remaining coal capacity, active regulatory proceedings, and distinct economic and policy contexts: North Carolina, Georgia, Missouri, Kansas, and Oklahoma. Across these five states, the analysis identifies 50 currently operating coal generating units at 25 plants, totaling 29,590 MW of nameplate capacity, with a fleet-wide average age of approximately 46 years.

Coal's displacement from its dominant position in the U.S. electricity sector is the product of successive shifts in the economics of electricity generation – the shale gas revolution beginning in 2009, and the rapid cost decline of utility-scale renewables through the 2010s and 2020s – neither of which has reversed. The combined effect has left the U.S. coal fleet in a structurally compromised position. The economics of operating an aging coal plant deconstruct into four cost components – fixed O&M, variable O&M, capital expenditure, and fuel – each governed by different drivers and the first three worsening as the fleet ages. These components do not operate independently: capacity factor decline, driven by gas and renewable competition, reduces the denominator over which fixed costs are allocated, raising the per-MWh burden and further weakening the plant's dispatch position. The weighted average cost of coal-fired power rose 28 percent between 2021 and 2024, to $46/MWh – nearly double the rate of general inflation over that period – as capacity factors declined. NERC data show that the average unplanned outage rate for coal plants rose from approximately 8 percent (2014–2017) to 11.4 percent (2020–2023), well above the comparable rates for natural gas and nuclear.

Across the five-state sample, fleet-wide capacity factor fell from 59.0 percent in 2014 to 33.3 percent in 2024 – a 44 percent relative decline that was effectively continuous through

2020, with a partial recovery in 2021 driven by the temporary collapse of natural gas competition before returning to the long-run trajectory thereafter. Heat rates degraded unidirectionally over the same period. Real delivered fuel costs, by contrast, tell a more nuanced story: the fleet-wide weighted average declined 14 percent in real terms from 2014 to 2024, indicating that coal's competitive position eroded not because coal fuel got more expensive in real terms, but because alternatives – particularly natural gas and wind – got cheaper faster. A roughly 2.5–2.8× delivered cost differential separates Eastern-supplied states (North Carolina and Georgia, at $4.14–$4.51/MMBtu in 2024) from Western-supplied states (Missouri, Kansas, and Oklahoma, at $1.61–$2.16/MMBtu in 2024), with most plants in the sample structurally locked into single-basin sourcing that amplifies rather than dampens fuel-cost volatility.

These concerns do not establish that degraded coal plants represent the least-cost or most reliable solution to near-term capacity needs – and the costs of attempting to treat them as such are already measurable. Consumers Energy reported that compliance with DOE Section 202(c) emergency orders cost $80 million in net costs between May and September 2025 alone to keep the J.H. Campbell plant operating – equivalent to more than $615,000 per day. An independent analysis by Grid Strategies estimated that if similar orders were applied to all large fossil plants scheduled to retire by the end of 2028, the annual cost to ratepayers could reach $3.1 billion, rising to $5.9 billion under a broader scenario. In June 2026, the Trump Administration invoked the Defense Production Act to direct approximately $700 million toward the domestic coal sector – underscoring the scale of policy intervention now required to sustain continued coal operation against prevailing market forces.

This paper does not assume arbitrary coal retirement dates or advocate for any particular resource portfolio outcome. The economics of coal cannot be evaluated in a vacuum. The paper therefore treats the retirement question as an inherently comparative one – examining the costs and performance of existing coal assets alongside the costs of available alternatives, and suggesting key considerations for regulators to make that comparison rigorously. The authors do not seek to relitigate the policy debate over coal's role in the energy transition, but to equip regulators, intervenors, and other participants in resource planning and rate proceedings with an assessment of coal's costs and whether continued reliance on aging coal assets represents the least-cost, least-risk path for ratepayers, compared to available alternatives in an era of rising electricity demand.

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1. Introduction

Surging electricity demand across the United States has reshaped the terms of the national energy discourse. While uncertainty remains high, recent updates to load forecasts have captured the attention of regulators and policymakers across the country. The buildout of artificial intelligence infrastructure – most notably the proliferation of data centers of varying sizes – and the broader electrification of transportation and industry have driven load growth projections to levels not seen in decades, with a recent analysis estimating the five-year peak demand growth forecast to be at 166 GW.[1] Against this backdrop, a renewed interest from the federal level in delaying the retirement of coal-fired power plants has surfaced – framed by some policymakers and grid operators as a necessary response to load forecasts, reliability imperatives, and constrained capacity margins.

This framing deserves rigorous scrutiny. A synthetic review of recent analyses suggests that the economic case for coal retirement has not weakened as demand has risen in recent years. Indeed, trends suggest that the structural cost disadvantages of aging coal assets have deepened and that skipping past a careful economic analysis runs the risk of passing high costs onto ratepayers in coal-dependent jurisdictions. Yet, according to U.S. Energy Information Administration (EIA) data, coal generation in the U.S. increased 13 percent in 2025.[2] In the last two decades, coal has only posted annual increases in generation five times.[3] Relatedly, and likely due to the Trump Administration's emergency orders under Section 202(c) of the Federal Power Act, the U.S. power sector in 2025 retired only 2.6 GW of coal-fired generating capacity across four power plants, the least since 2010.[4]

This paper synthesizes recent analyses and draws on publicly available utility filings, market data, and recent cost benchmarks to examine the economic fundamentals underlying current coal performance at the national level and in select states. The authors do not seek to relitigate the policy debate over coal's role in the energy transition, but to equip regulators with an assessment of coal's costs and whether a continued reliance on aging coal assets represents the least-cost, least-risk path for ratepayers, compared to available alternatives in an era of rising electricity demand.

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[1] John D. Wilson, Sophie Meyer, Zach Zimmerman, and Rob Gramlich, "Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers," Grid Strategies LLC, November 2025, https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf.

[2] U.S. Energy Information Administration, *Electric Power Monthly*, February 2026, https://www.eia.gov/electricity/monthly/archive/february2026.pdf, pp.12.

[3] Benjamin Storrow, "Coal Is Booming. Here's What It Means for Climate Pollution," *E&E News* (*Climatewire*), 2 March 2026, https://www.eenews.net/articles/coal-is-booming-heres-what-it-means-for-climate-pollution/

[4] U.S. Energy Information Administration (EIA), "U.S. Coal-Fired Generating Capacity Retired in 2025 Was the Least in 15 Years," *Today in Energy*, 13 April 2026, https://www.eia.gov/todayinenergy/detail.php?id=67427.

Importantly, this paper does not assume arbitrary coal retirement dates or advocate for any particular resource portfolio outcome. The economics of coal cannot be evaluated in a vacuum. The paper therefore treats the retirement question as an inherently comparative one – setting up subsequent examinations of the costs and performance of existing coal assets alongside the costs of available alternatives, and suggesting key considerations for regulators to make that comparison rigorously.

1.2 Context and Motivation

This analysis is timely because forecasted surges in electricity demand are colliding with a renewed political and commercial interest in delaying coal retirements. For example, in June 2026, the Trump Administration invoked the Defense Production Act – a Cold War-era law granting broad presidential authority over industries deemed critical to national security – to direct approximately $700 million toward the domestic coal sector. The funding package allocates $425 million for infrastructure upgrades at 13 existing coal-fired power plants, $75 million toward a proposed West Coast coal export terminal, and up to $350 million for new coal facility development, including new plants in Alaska and West Virginia.[5,6] Similarly, the Administration's Section 202(c) emergency orders to prevent scheduled coal plant retirements have introduced significant new uncertainty into planning processes across the country.[7,8] Grid operators in regions including PJM, MISO, and SPP have flagged resource adequacy concerns as planned retirements have accelerated while new capacity additions, especially renewables, have faced compounded interconnection delays and supply chain constraints. At the end of 2024, there were about 10,300 projects actively seeking grid interconnection across the country, representing 1,400 GW of generation and approximately 890 GW of storage.[9] To maintain reliability, and in the face of an ongoing gas price elevation, grid operators and regulators are weighing the benefits of extending coal to address resource adequacy concerns and buy time for additional capacity to come online.

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[5] Jarrett Renshaw and Timothy Gardner, "Trump to Unveil $700 Million Coal Support Plan Using Emergency Powers," Reuters, 4 June 2026, https://www.reuters.com/legal/litigation/trump-unveil-700-million-coal-support-plan-using-emergency-powers-2026-06-04/.

[6] U.S. Department of Energy, "Fact Sheet: The Energy Department is Unleashing Beautiful, Clean Coal," Energy.gov, 4 June 2026, https://www.energy.gov/articles/fact-sheet-energy-department-unleashing-beautiful-clean-coal. The DOE fact sheet states: "$425 million will support 13 coal plants and save over 14 GW of coal-fired power capacity – enough generation to power more than 14 million American homes. These coal plants will span ten states – including Oklahoma, Arkansas, Arizona, Tennessee, West Virginia, Kentucky, North Carolina, Indiana, Wisconsin, and North Dakota – strengthening reliable coal supply chains across the country.

[7] U.S. Department of Energy (DOE), "DOE's Use of Federal Power Act Emergency Authority," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.

[8] Martucci, Brian, "DOE emergency orders for fossil plants complicate utility planning, experts say." 19 March 2026, Utility Dive, https://www.utilitydive.com/news/doe-emergency-orders-for-fossil-plants-complicate-utility-planning-experts/815186/.

[9] Rand et al., "Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2024," Lawrence Berkeley National Laboratory, December 2025, https://emp.lbl.gov/publications/queued-2025-edition-characteristics.

While legitimate planning inputs, these concerns do not establish that degraded coal plants represent the least-cost or most reliable solution to near-term capacity needs. The relevant question for regulators is not whether electricity demand is growing, but whether the specific coal assets proposed for continued operation – or the fleet, writ large – can deliver reliable, affordable power at a cost that ratepayers should be asked to bear, especially where alternatives exist that are less expensive. For example, if renewables combined with long duration storage and paired with energy efficiency can cost-effectively serve morning and evening peaks throughout the year, regulators may have an opportunity to alleviate some demand pressure on natural gas, which alleviates some cost pressure on natural gas, and has the cascading effect of alleviating demand pressure to keep aging coal assets operating.

1.3 Scope of the Analysis

This paper proceeds as follows. Section 2 examines the economic fundamentals of coal power at the national level, tracing the structural shift in coal's competitive position from its peak dominance in the mid-2000s through the natural gas price disruption of the 2009-2019 period and into the current era of renewable cost competitiveness amidst load growth pressures and renewed interest by the Trump Administration to delay planned retirements. It analyzes the cost stack of aging coal operations – fixed and variable operations and maintenance, heat rate degradation, environmental compliance capital expenditures, and fuel cost exposure – using data from EIA Forms 860 and 923, FERC Form 1, and published cost benchmarks.

Section 3 examines coal's current and projected role on the grid: when and where coal plants are dispatched, how their capacity factors have evolved, and what the grid-level implications of continued operation versus managed retirement look like under realistic planning assumptions.

Section 4 presents state-level case studies for North Carolina, Georgia, Missouri, Kansas, and Oklahoma – five jurisdictions with significant remaining coal capacity, active regulatory proceedings, and distinct economic and policy contexts. For each state, the analysis synthesizes key data on plant age and size, operational performance and downtime history, operations and maintenance costs, and fuel sourcing and cost volatility. The data sources for these case studies draw primarily on EIA Form 860 generator-level data, EIA Form 923 fuel and generation records, FERC Form 1 financial filings, and utility IRP filings with state commissions.

The paper concludes with a set of key considerations for regulators and other participants in resource planning and rate proceedings – addressing how the economic evidence should inform retirement decisions, cost recovery frameworks, and the treatment of claims that aging coal assets are essential to grid reliability and customer affordability.

Ultimately, this analysis is designed to lay a foundation for a broader question: given the economics synthesized here, what role can and should coal play in the most cost-effective and reliable mix of resources available to meet load growth over the next several years?

2. The Economic Fundamentals of Coal

2.1 Shifts in Market Fundamentals Due to Technology

Coal's displacement from its dominant position in the U.S. electricity sector is the product of successive shifts in the economics of electricity generation – each driven by technological change and market forces that have altered the competitive landscape that coal generation faces. For most of the twentieth century, coal occupied the position of the least-cost baseload generation resource in the United States. The coal fleet has contracted sharply since 2010. Understanding that sequence is essential to evaluating claims that coal's decline can or should be reversed through policy intervention, because it clarifies what would have to be true for such a reversal to serve ratepayer interests.

Between 2000 and 2008, coal supplied approximately 50 percent of total U.S. electricity generation, sustained by its advantage over natural gas in fuel cost. During that period, the average Henry Hub natural gas spot price exceeded $6 per million British thermal units, making gas-fired generation materially more expensive than coal on a per-megawatt-hour basis across most of the country.[10]

Coal's primacy slipped beginning in 2009. The shale gas revolution – the convergence of hydraulic fracturing and horizontal drilling technologies that unlocked vast quantities of previously inaccessible natural gas reserves – flooded domestic markets with supply and drove Henry Hub prices to historic lows.[11] By 2012, the benchmark price had fallen to $2.77 per MMBtu, less than half its 2008 average. The competitive floor beneath coal's market position collapsed. The consequences were swift and structural: natural gas surpassed coal as the leading source of U.S. electricity generation for the first time in April 2015, and crossed coal on an annual basis in 2016. Coal's share of generation, which had exceeded 50 percent as recently as 2005, fell to roughly 28 percent by 2018 and has continued declining.[12] Gas-fired generation, by contrast, rose to approximately 40 percent

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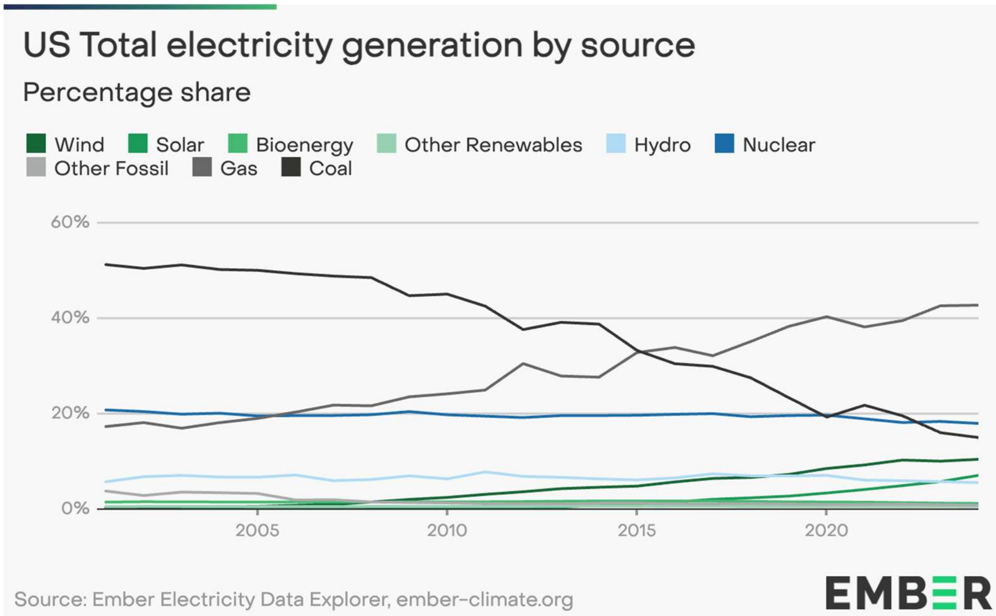
[10] U.S. Energy Information Administration, "Natural Gas Expected to Surpass Coal in Mix of Fuel Used for U.S. Power Generation in 2016," *Today in Energy*, 14 July 2015, https://www.eia.gov/todayinenergy/detail.php?id=25392.

[11] Dallas Federal Reserve Bank, "Overflowing U.S. Shale Gas Increasingly Streams to Mexico and onto Global Markets," *Southwest Economy*, 2025, https://www.dallasfed.org/research/swe/2025/swe2514.

[12] U.S. Energy Information Administration, "Natural Gas Expected to Surpass Coal." See also Energy Innovation Policy and Technology LLC, "What Is Coal's Future in the United States?" 10 November 2025, https://energyinnovation.org/expert-voice/what-is-coals-future-in-the-united-states/.

of the national electricity mix – a transformation of the generation fleet that was driven by economics.[13]



[14]

Installed coal capacity dropped from 317.6 GW in 2011 to 221 GW in 2022 – with nearly a quarter of the remaining 2022 total slated for retirement by 2029.[15][16] In 2025, coal accounted for approximately 15 percent of U.S. electricity generation, with 190 GW of installed capacity – down 43 percent from the fleet's 2010 peak of 340 GW.[17]

The second competitive disruption arrived in the form of rapidly declining renewable costs. The levelized cost of utility-scale solar fell by more than 90 percent between 2010 and 2022, and onshore wind followed a similar trajectory. By the mid-2020s, both technologies had established themselves as the lowest-cost form of new-build electricity generation on an unsubsidized basis in most U.S. markets, according to Lazard's annual Levelized Cost of Energy analysis and BloombergNEF's parallel global benchmark.[18] The competitive

[13] U.S. Energy Information Administration, Short-Term Energy Outlook, April 2026, https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf.
[14] https://ember-energy.org/data/us-electricity-data-explorer/
[15] "68% of U.S. Coal Fleet Retirements Since 2011 Were Plants Fueled by Bituminous Coal," U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=49336.
[16] U.S. Energy Information Administration, "Nearly a Quarter of the Operating U.S. Coal-Fired Fleet Scheduled to Retire by 2029," Today in Energy, 7 November 2022, https://www.eia.gov/todayinenergy/detail.php?id=54559.
[17] Global Energy Monitor, *Global Coal Plant Tracker,* January 2022, https://globalenergymonitor.org/projects/global-coal-plant-tracker/dashboard/.
[18] BloombergNEF, Levelized Cost of Electricity 2026 (New York: BloombergNEF, 18 February 2026), https://about.bnef.com/insights/clean-energy/battery-storage-costs-hit-record-lows-as-costs-of-other-clean-

pressure from renewables operates differently than the gas displacement of the prior decade: where gas competed with coal primarily on fuel cost, renewables compete on total delivered cost – and renewables carry zero fuel cost, eliminating the commodity price volatility that has historically been coal's primary cost risk. In 2020, renewable energy generation surpassed coal for the first time.[19]

The combined effect of these two disruptions has left the U.S. coal fleet in a structurally compromised position from which market forces alone – absent sustained policy intervention – are unlikely to present a recovery path. Aside from a plant in Alaska, whose development pathway remains uncertain, virtually no new coal-fired generation capacity is under development anywhere in the country.[20] The fleet is aging, with no infusion of new units to offset the cost escalation and performance degradation that characterize aging assets.

2.2 Evaluating the Cost Stack of the Coal Fleet

The economics of operating a coal-fired power plant deconstruct into four distinct cost components, each governed by different drivers and each evolving in different ways as the U.S. coal fleet ages. This section frames those four components conceptually, draws on published cost ranges from the Electric Power Research Institute (EPRI), the U.S. Energy Information Administration (EIA), and Sargent & Lundy, and provides context for the operational and fuel costs findings developed in subsequent sections. [21] [22]

power-technologies-increased-bloombergnef/; Lazard, Levelized Cost of Energy+ Version 18.0 (New York: Lazard, June 2025).

[19] U.S. Energy Information Administration, "Renewables became the second-most prevalent U.S. electricity source in 2020," Today in Energy, 28 July 2021, https://www.eia.gov/todayinenergy/detail.php?id=48896

[20] The Alaska plant is the 1.25 GW Terra Energy Center. Announced in 2026 and described as the first new U.S. coal plant in more than a decade, it is still at the planning/early development and equipment-procurement stage, not yet in full construction, and its viability is uncertain. Recent media coverage notes that the project depends on a new mine that does not yet exist, and, like other new supply-side decisions, its fate is tied to an uncertain AI-driven load build-out and shifting political conditions. See: Hannah Northey, "The First US Coal Plant in a Decade Is on Shaky Ground," E&E News by POLITICO, 20 March 2026, https://www.eenews.net/articles/the-first-us-coal-plant-in-a-decade-is-on-shaky-ground/.

[21] Sargent & Lundy, LLC, *Generating Unit Annual Capital and Life Extension Costs Analysis*, Project No. 13651-001, prepared for the U.S. EIA, December 2019, https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[22] U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2026: Electricity Market Module*, April 2026, Table 8.2, https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf. EIA's published 2025-dollar cost assumptions for new ultra-supercritical coal include $42.49/kW-year fixed O&M, $4.71/MWh variable O&M, and overnight capital cost of $4,074/kW.

EIA's December 2019 study linking plant-level operating cost to retirement rates documents the empirical pattern: from 2008 through 2017, the highest-cost decile of U.S. coal plants (operating at $28–$40/MWh in total O&M cost) experienced disproportionately greater retirement rates than the lowest-cost decile (operating at $20–$26/MWh).[23] Cost-stack heterogeneity is therefore not an accounting curiosity but a leading indicator of retirement risk.

Table 1: The four components of the coal-plant cost stack

Component	Reporting Unit	Typical Range	Behavior
Fixed O&M	$/kW-year	$30–$120/kW-year	Largely independent of generation in the short run; rises with plant age and accelerates after ~40 years.
Variable O&M	$/MWh	$3–$8/MWh	Scales with generation. Rises modestly with heat-rate degradation and with environmental control activity.
Capital	$/kW (discrete)	$50–$600/kW	Lumpy: dominated by environmental retrofits, ash pond closure, and life-extension expenditures. Material changes reset the facility's economics.
Fuel	$/MWh (= HR × $/MMBtu / 1,000)	$15–$50/MWh	Scales with generation and with fuel-market conditions. Carries explicit commodity-price risk that does not exist for renewables or nuclear.

2.2.1 Fixed Operations and Maintenance

Fixed O&M comprises the labor, materials, insurance, property tax, and overhead expenses required to keep a plant available to generate, regardless of whether the plant actually generates. It is reported in dollars per kilowatt of nameplate capacity per year ($/kW-year). For a newly constructed ultra-supercritical coal unit, EIA's published 2025-dollar Fixed O&M assumption is approximately $42/kW-year.[24] For the existing

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[23] U.S. Energy Information Administration, "Coal plant retirements linked to plants with higher operating costs," *Today in Energy*, 3 December 2019, https://www.eia.gov/todayinenergy/detail.php?id=42155.

[24] U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2026: Electricity Market Module*, April 2026, Table 8.2, https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf. EIA's published 2025-dollar cost assumptions for new ultra-supercritical coal include $42.49/kW-year fixed O&M, $4.71/MWh variable O&M, and overnight capital cost of $4,074/kW.

operating fleet – which is more relevant to this analysis – Fixed O&M is materially higher and rises with age.

The EIA-commissioned Sargent & Lundy 2018 study documented a statistically significant relationship between plant age and O&M spending for fossil-steam coal plants. Drawing on FERC Form 1 data covering U.S. coal plants 2002–2016, the S&L analysis found that Fixed O&M for typical operating coal units falls in the range of $30–$60/kW-year for plants in their first 30 years of service, rising to $60–$100/kW-year for plants in the 30–50 year band, and approaching or exceeding $100–$120/kW-year for plants beyond 50 years of service.

EPRI research has documented that Fixed O&M spending accelerates after roughly 40 years as cumulative thermal cycling, tube fouling, instrumentation drift, and the cumulative effects of deferred maintenance compound. [25] The 2010s and 2020s have added a second source of pressure: as coal plants have shifted from baseload to load-following and cycling duty (driven by gas and renewable competition), the equipment stress associated with frequent ramping has further elevated the maintenance burden. EPRI's research framework on flexible operations has emphasized that traditional cycling-cost calculations – focused on startup fuel, additional staffing, and heat-rate penalty – substantially understate the true economic impact, because they omit equipment damage, accelerated tube failures, and unplanned-outage risk.

Fixed O&M is the most consequential cost component at low capacity factor. Because Fixed O&M is paid regardless of generation output, lower utilization means each MWh produced absorbs a larger share of the same fixed cost – a scenario Carbon Tracker has described as "devastating for coal power economics" when running hours fall. [26][27] The mathematics of fixed-cost allocation is the principal mechanism through which capacity factor decline translates into cost-stack pressure, and it is the mechanism most likely to drive retirement decisions for plants whose capacity factor has fallen significantly.

2.2.2 Variable Operations and Maintenance

Variable O&M is the consumable and waste-handling cost that scales with generation: limestone or lime for FGD scrubbers, ammonia or urea for SCR/SNCR systems, activated carbon for mercury control, water treatment chemicals, sorbents, and waste disposal. It is

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[25] Electric Power Research Institute, "Understanding the Price of Flexible Operations," *EPRI Journal*, August 2022, https://eprijournal.com/understanding-the-price-of-flexible-operations/.

[26] Carbon Tracker Initiative, "Understanding the operating costs of coal power: US example," April 2024, https://carbontracker.org/reports/understanding-operating-cost-coal-fired-power-us-example/.

[27] For example, A plant carrying $80/kW-year in Fixed O&M at 60% capacity factor allocates the cost at $15.21/MWh ($80,000 ÷ (0.60 × 8,760)); the same plant at 20% capacity factor allocates the same Fixed O&M at $45.66/MWh – a 3× per-MWh increase from the same dollar input.

reported in dollars per megawatt-hour ($/MWh). For the existing operating fleet, Variable O&M typically falls in the $3–$8/MWh range, with newer or less-controlled plants at the lower end and older plants with full retrofits and substantial chemical-consumable burdens at the upper end.

The more economically important driver of "variable" cost behavior is heat rate. As units burn more fuel per unit of electricity produced – whether due to age-related component degradation, cycling-induced thermodynamic losses, or environmental control parasitic loads – the variable fuel cost per MWh rises mechanically through the heat-rate term in the fuel cost formula.[28] Heat-rate degradation therefore acts as a cost multiplier on the fuel-cost component also explored in this section, even though it is properly classified as an operational characteristic.

EPRI has documented that the contemporary U.S. coal fleet has experienced widespread heat-rate degradation, with current estimates suggesting fleet-wide efficiency has dropped by several percentage points relative to design heat rates. [29] Three reinforcing causes have driven the degradation. First, the cumulative addition of post-combustion environmental controls (FGD scrubbers, SCR/SNCR systems, baghouses, and ACI) imposes parasitic loads of typically 1–3% of gross output, raising net heat rates correspondingly. Second, declining coal quality – particularly the shift toward higher-moisture-content Powder River Basin (PRB) subbituminous coal – has reduced unit performance at many plants. Third, and most consequentially in recent years, the proliferation of low-marginal-cost renewable and gas generation has forced once-baseload coal units into more frequent cycling and lower turndown operation.

The heat-rate trajectory is unidirectional: there is no documented mechanism for fleet-wide efficiency recovery without capital reinvestment that, for most plants, no longer pencils against remaining economic life.

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[28] Heat-rate-driven variable fuel cost is computed as: $/MWh fuel = (Heat Rate, Btu/kWh) × ($/MMBtu) ÷ 1,000. The formula isolates the joint effect of plant efficiency (heat rate, plant-specific) and basin economics (delivered fuel cost) on the largest variable cost component for coal generation. For example, a plant with a 10,500 Btu/kWh heat rate burning $2.00/MMBtu coal incurs $21.00/MWh in fuel cost; the same plant burning $5.00/MMBtu coal incurs $52.50/MWh.

[29] S. Korellis, "Coal-Fired Power Plant Heat Rate Improvement Options, Part 1," *POWER Magazine*, 3 November 2014, https://www.powermag.com/coal-fired-power-plant-heat-rate-improvement-options-part-1/. The article documents that operational changes since the 1980s – including emissions control retrofits, declining coal quality, and the proliferation of renewable and gas generation – have all worked against heat rate improvements, with current estimates suggesting fleet-wide efficiency has dropped by several percentage points.

2.2.3 Capital Expenditure

Capital expenditure (CAPEX) falls into two distinct categories with very different economic profiles. Recurring (non-environmental) CAPEX covers boiler tube replacements, turbine overhauls, condenser retubes, and balance-of-plant equipment refurbishment that occur on multi-year cycles as a normal cost of operating an aging plant. The Sargent & Lundy 2018 study estimated this category at approximately $30–$80/kW-year on an annualized basis for typical operating coal plants, with the upper end of the range applicable to older, partial-load units that are also burdened with maintenance backlogs.[30] Combined with Fixed O&M, recurring CAPEX produces a typical combined fixed-cost burden of $70–$200/kW-year across the operating fleet.

The second category of CAPEX is qualitatively different: large, discrete CAPEX triggered by environmental regulation. These expenditures do not occur on routine maintenance cycles; they occur when a regulation tightens or when a previously-deferred upgrade can no longer be postponed.

The economic implication of discrete environmental CAPEX depends critically on remaining plant life. A plant with 20+ years of remaining life can amortize a $400/kW retrofit at approximately $30–$40/kW-year, which is supportable for a workhorse-tier plant operating at high capacity factor with low fuel cost. A plant with 10 years or less of remaining life cannot recover the same investment under any reasonable rate-base treatment: the same $400/kW would require roughly $50–$70/kW-year in amortization, by itself exceeding the entire fixed-cost burden of an unstressed coal plant. For aging or marginal-tier plants, environmental retrofit triggers are therefore tantamount to forced retirements unless paired with substantial life-extension capital. The retrofit-or-retire decision is the single most consequential type of capital event facing the operating coal fleet in any forward policy scenario.

2.2.4 Fuel Cost

Variable fuel cost is a product of plant-specific heat rate (in Btu/kWh) and delivered fuel cost (in $/MMBtu), divided by 1,000 to reconcile the units.[31] It is the largest single line item in the cost stack for most operating coal plants and the most variable year over year. Unlike renewables, which carry zero marginal fuel cost, and unlike nuclear, which has fuel costs that are stable over multi-year contracts, coal carries ongoing commodity price

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[30] Sargent & Lundy, LLC, *Generating Unit Annual Capital and Life Extension Costs Analysis*, Project No. 13651-001, prepared for the U.S. EIA, December 2019, https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[31] The heat rate and delivered fuel costs cited below are from authors' analysis of U.S. Energy Information Administration Form EIA-923, Page 1 (Generation and Fuel Data) and Schedule 2 (Fuel Receipts and Costs), 2024, https://www.eia.gov/electricity/data/eia923/.

risk that must be modeled under multiple scenarios for any forward-looking economic analysis. Specifically, three sources of fuel-cost volatility matter:

1. Basin-driven supply economics – Data suggests there was a roughly 2.5–2.8× delivered cost differential between Eastern bituminous coal (delivered to the Carolinas and Georgia at approximately $4.14–$4.51/MMBtu in 2024) and PRB subbituminous coal (delivered to Missouri, Kansas, and Oklahoma at approximately $1.61–$2.16/MMBtu in 2024).[32] Plant-level variable fuel cost in 2024 spanned $15.00/MWh (Hawthorn, MO; computed as 10,716 Btu/kWh × $1.40/MMBtu / 1,000) to $50.50/MWh (Bowen, GA; computed as 9,941 Btu/kWh × $5.08/MMBtu / 1,000) – a 3.4× spread that reflects basin sourcing and rail logistics rather than operational decisions within utility control[33].

2. Cross-fuel competition – Coal delivered prices respond to natural gas market conditions because gas-coal switching pressure operates through the dispatch order. The Henry Hub natural-gas spot price ranged from $2.03/MMBtu (2020) to $6.45/MMBtu (2022) over the 2014–2024 window. [34] The 2021–2022 gas spike pulled coal delivered prices upward as utilities competed to lock in physical coal deliveries during a window when gas-fired alternatives were even more expensive on a delivered-energy basis. Real coal delivered cost rose 23% from 2020 to 2023 before easing in 2024 as gas prices normalized[35]. That episode illustrates that coal fuel cost is not autonomous: any forward-looking projection of coal economics must take a view on natural gas prices rather than projecting coal supply curves in isolation.

3. Structural changes in the coal supply curve itself – Central Appalachian production has contracted sharply since 2008. EIA reports that Appalachian regional production fell from 390 million tons in 2008 to 200 million tons in

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32 Authors' analysis of U.S. Energy Information Administration Form EIA-923 Schedule 2 (Fuel Receipts and Costs), 2014–2024 annual releases, https://www.eia.gov/electricity/data/eia923/. Costs are MMBtu-weighted plant-year averages deflated to 2024 dollars using the BEA implicit GDP price deflator (NIPA Table 1.1.9, FRED series A191RD3A086NBEA).

33 Authors' analysis combining plant-level 2024 heat rates (U.S. Energy Information Administration Form EIA-923, Page 1, Generation and Fuel Data) with MMBtu-weighted delivered fuel costs (Form EIA-923, Schedule 2, Fuel Receipts and Costs), https://www.eia.gov/electricity/data/eia923/. Variable fuel cost $(/MWh) = heatrate(Btu/kWh) \times deliveredcost($/MMBtu) ÷ 1,000. Example values: Hawthorn, MO (10,716 Btu/kWh × $1.40/MMBtu = $15.00/MWh); Bowen, GA (9,941 Btu/kWh × $5.08/MMBtu = $50.50/MWh).

34 U.S. Energy Information Administration, "Henry Hub Natural Gas Spot Price," https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.

35 Authors' analysis of U.S. Energy Information Administration Form EIA-923 Schedule 2 (Fuel Receipts and Costs), deflated to 2024 dollars using the BEA implicit GDP price deflator (NIPA Table 1.1.9, FRED series A191RD3A086NBEA, accessed April 28, 2026). Fleet-wide real delivered cost rose from $2.20/MMBtu (2020) to $2.72/MMBtu (2023).

2018[36], and Appalachian production has continued to decline since, reaching 157.7 million tons in 2024[37]. PRB production has been more stable but is increasingly concentrated in fewer surface mines, with rail capacity rather than mine capacity often the key logistical constraint. Both contractions affect the delivered cost trajectory in basin-specific ways and represent forward risks that are not fully observable in current contract pricing.

The combined implication of these three drivers is that any cost-stack analysis used for forward asset-management or policy decisions should be run under multiple fuel-cost scenarios – at minimum a low-gas case (Henry Hub at $2.00–$3.00/MMBtu, broadly the 2014–2020 and 2023–2024 range), a high-gas case (Henry Hub at $5.00–$7.00/MMBtu, broadly the 2022 episode), and a structural-supply-shock case (incorporating possible mine closure or rail-capacity constraints). The state of the art in utility integrated resource planning routinely incorporates such fuel-cost scenarios; the equivalent rigor should apply to any regulatory or policy analysis that depends on coal economics. Coal's cost-stack disadvantage versus zero-fuel-cost alternatives is structural and grows with utilization decline, regardless of the fuel-cost scenario assumed.

2.2.5 Cost Stack Synthesis

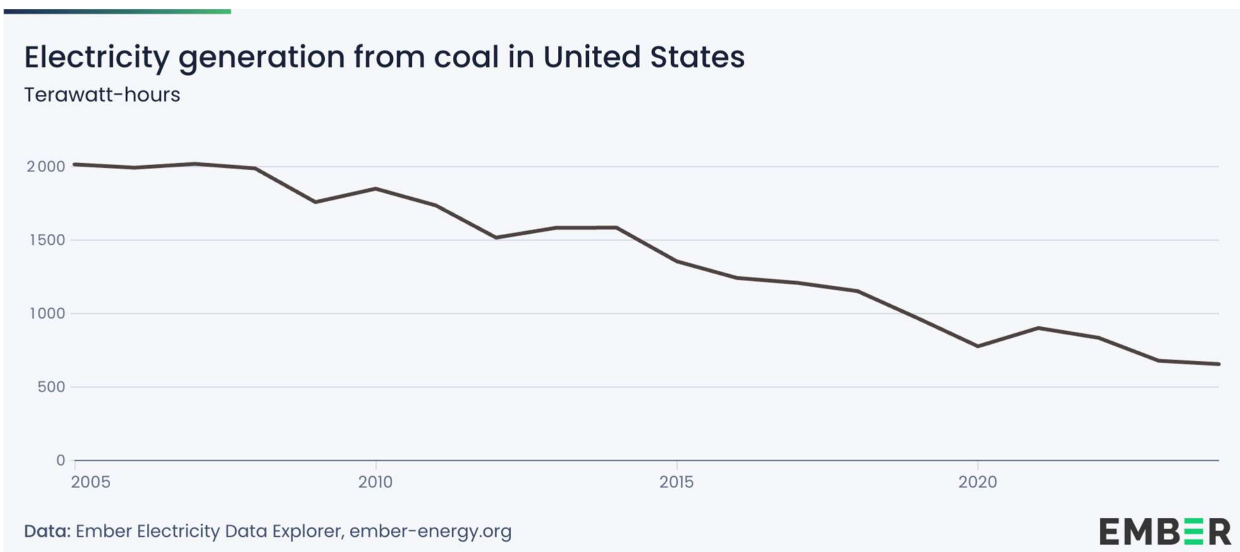
The four components of the coal-plant cost stack are governed by different drivers but interact in ways that compound economic stress on the operating fleet. These four components also do not operate independently. Capacity factor decline – driven by gas and renewable competition – reduces the denominator over which Fixed O&M and recurring CAPEX are allocated, raising the per-MWh burden. The same low-capacity factor, partial-load operation worsens heat rate, raising the per-MWh fuel burden. The combined effect is that the cost-stack pressure on aging coal plants is self-reinforcing: each margin of utilization lost amplifies the per-MWh cost of remaining utilization, which further weakens the plant's dispatch position.

[36] U.S. Energy Information Administration, "U.S. coal production employment has fallen 42% since 2011," *Today in Energy*, December 11, 2019, https://www.eia.gov/todayinenergy/detail.php?id=42275.
[37] U.S. Energy Information Administration, *Annual Coal Report 2024*, November 2025, Table 1, https://www.eia.gov/coal/annual/pdf/acr.pdf.

3. The Grid Role of Coal

3.1 Recent Resurgence Amidst Rising Costs and Declining Capacity Factors

For over a hundred years, coal was the country's largest source of electricity. As previously outlined, this dynamic shifted fundamentally in the 21st century. In 2025, coal accounted for approximately 15 percent of U.S. electricity generation, with 190 GW of installed capacity – down 43 percent from the fleet's 2010 peak of 340 GW.[38] While coal is in the midst of what could be characterized as a managed decline, its role on the grid in 2026 is best described as a peaking and gap-filling resource that has been propped up by recent policy interventions and fluctuations in natural gas prices. Compared to the previous two decades in the electricity sector, which saw flat demand, declining coal generation, and declining carbon emissions, 2025 saw an uptick in all three. Most of the growth in fossil fuel power generation came from coal-fired power plants in 2025, which saw coal generation rise by 80 million MWh due to a combination of increasing demand, federal emergency orders which continued the operation of several plants, and rising natural gas prices [39]



This recent resurgence in coal belies a fundamental economic reality for the country's aging coal fleet. Over the past 10-15 years, coal plants have been used less and less, even though they are still physically capable of producing far more power than the grid is actually asking them to provide. Due to a variety of factors, most notably increasing operations and maintenance costs, the weighted average cost of a megawatt-hour (MWh)

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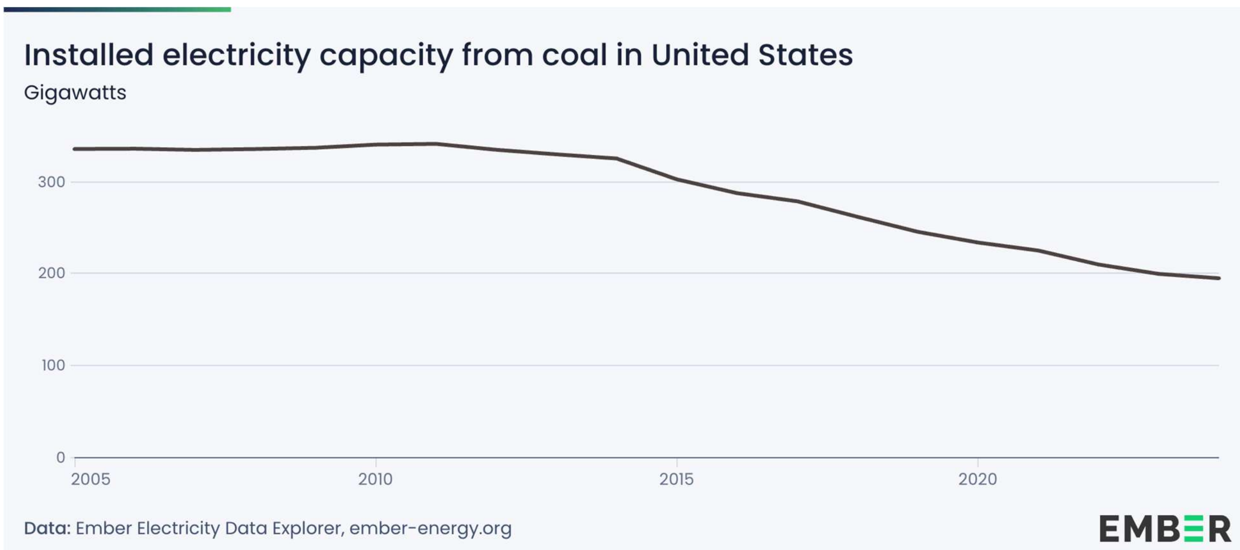
[38] Global Energy Monitor, Global Coal Plant Tracker Dashboard, Accessed 13 April 2026, https://globalenergymonitor.org/projects/global-coal-plant-tracker/dashboard/.

[39] Thomas, Michael. "The US Power Grid Had A Dirty Year in 2025," *Distilled*, 6 January 2026, https://www.distilled.earth/p/the-us-power-grid-had-a-dirty-year.

of coal-fired power was $46/MWh in 2024, up 28 percent from 2021 levels.[40] Across that timeline, which included a major shock to the market in the Russian invasion of Ukraine, coal plant capacity factors dropped to 38 percent in 2024 from 46 percent in 2021.[41]

The decline in coal's average capacity factor occurred alongside consistent reductions in total installed capacity – meaning the coal fleet since the 2010s has not only shrunk but that the plants that are still running are doing so less than ever, aside from a slight increase in 2025 due to rising natural gas prices and overall increased electricity demand. Analyses show that even the retirement of the oldest and least efficient units has not led to an increase in utilization in other plants.[42] As fixed operating and maintenance costs grow as plants age, the rising fixed O&M costs are being spread across a decreasing volume of generation, which has led to coal's increased cost in $/MWh figures presented in the Energy Innovation report referenced in foonote 38.



3.2 Policy Interventions Seek to Prop Up an Aging Fleet

In early 2025, the Trump Administration signaled its interest in revitalizing coal through a series of executive orders, including Executive Orders 14261 and 14262 in April 2025.[43]

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[40] Myers, Amanda, and Mike O'Boyle, "Coal Power 28 Percent More Expensive in 2024 Than in 2021," Energy Innovation, 2025. https://energyinnovation.org/wp-content/uploads/Coal-Cost-Update.pdf.
[41] Ibid.
[42] Wamsted, Dennis and Seth Feaster, "Nowhere to go but down for U.S. coal capacity, generation," Institute for Energy Economics and Financial Analysis (IEEFA), 24 October 2024. https://ieefa.org/resources/nowhere-go-down-us-coal-capacity-generation.
[43] Hubbell et al., "If/Then: The Uncertain Future of Coal and What It Means for Climate, Air Quality, and the Energy Economy," *Common Resources*, Resources for the Future, 17 February 2026, https://www.resources.org/common-resources/ifthen-the-uncertain-future-of-coal-and-what-it-means-for-climate-air-quality-and-the-energy-economy/.

These policy moves, coupled with DOE emergency orders, seek to overcome the engineering and economic realities facing the U.S. coal fleet.

According to a 2023 Brattle Group review of coal-fired electricity generation in the United States, the average age of the operating coal fleet had reached 47.2 years.[44] Aging plants require more frequent and more expensive maintenance. Their heat rates – the efficiency with which they convert fuel to electricity – degrade over decades of operation. Emissions control equipment is either approaching the end of its useful life or has never been installed, exposing owners and ratepayers to significant capital outlays to maintain regulatory compliance. And because virtually no new coal-fired capacity is under development anywhere in the country, the fleet will only continue to age, with no prospect of cost improvement through technology renewal. It is against this backdrop that BloombergNEF's most recent annual Levelized Cost of Electricity report – published in February 2026 – documented that global coal LCOE, after a period of relative competitiveness with gas combined-cycle plants, has again ticked upward as equipment and operating costs for aging thermal assets continue to escalate.[45]

NERC data show that the average unplanned outage rate for coal plants rose from approximately 8 percent between 2014 and 2017 to 11.4 percent between 2020 and 2023 – well above the comparable rates for natural gas (7.7 percent) and nuclear (2 percent).[46] Operating costs have followed the same upward trajectory, rising 28 percent between 2021 and 2024, nearly double the rate of general inflation over that period.[47] States with disproportionately coal-heavy generation mixes have seen electricity prices rise faster than those that have diversified into lower-cost resources.[48]

As of early 2026, the Department of Energy (DOE) has issued emergency orders to prevent the retirement of at least five coal facilities representing at least 4.4 GW of coal capacity.[49]

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[44] The Brattle Group, "A Review of Coal-Fired Electricity Generation in the U.S." (Cambridge, MA: The Brattle Group, April 2023), https://www.brattle.com/wp-content/uploads/2023/04/A-Review-of-Coal-Fired-Electricity-Generation-in-the-U.S..pdf.

[45] BloombergNEF, "Levelized Cost of Electricity 2026," 18 February 2026, https://about.bnef.com/insights/clean-energy/battery-storage-costs-hit-record-lows-as-costs-of-other-clean-power-technologies-increased-bloombergnef/.

[46] North American Electric Reliability Corporation (NERC). *2025 State of Reliability: Technical Assessment.* June 2025. https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2025_technical_assessment.pdf.

[47] Michelle Solomon, "What Is Coal's Future in the United States?" Energy Innovation, 10 November 2025, https://energyinnovation.org/expert-voice/what-is-coals-future-in-the-united-states/.

[48] Niemeyer, Liam. "Heavy Reliance on Coal Has Eroded a KY Economic Advantage. Can Trump Reverse the Trend?" *Kentucky Lantern*, 10 April 2025. https://kentuckylantern.com/2025/04/10/heavy-reliance-on-coal-has-eroded-a-ky-economic-advantage-can-trump-reverse-the-trend/.

[49] U.S. DOE, "2025 DOE 202(c) Orders," https://www.energy.gov/ceser/2025-doe-202c-orders; see also Sonal C. Patel, "DOE's Section 202(c) Emergency Orders Since May 2025: 43 and Counting," POWER

Table 2: Plants targeted by recent DOE emergency orders

Plant/Unit	State	Owner	Capacity	DOE 202(c) Order
J.H. Campbell Generating Station	MI	Consumers Energy	~1,560MW	Through 5/18/26
Schahfer Generating Station, Units 17 & 18	IN	NIPSCO	~847MW	Through 6/21/26
F.B. Culley Generating Station, Unit 2	IN	CenterPoint Energy	~268MW	Through 6/21/26
Centralia Generating Station, Unit 2	WA	TransAlta	~670MW	Through 6/14/26
Craig Station, Unit 1	CO	Tri-State[50]	~427MW	Through 6/28/26

These orders have already produced direct, quantifiable ratepayer costs: Consumers Energy, owner of the J.H. Campbell plant, reported that compliance with DOE orders cost $80 million in net costs between May and September 30, 2025 alone – equivalent to more than $615,000 per day.[51] If these costs were necessary for preserving system reliability the orders might be understandable, but that does not appear to be the case.

In many cases, these orders run counter to the plans and recent economic decisions made by the plant's owner and operator. For example, in the case of Centralia, its retirement was codified in state law and TransAlta said in December 2025 that it had partnered with Puget Sound to convert Unit 2 to natural gas under a 15-year deal starting in late 2028. In response to the DOE order, the CEO of TransAlta stated in March 2026 that they are complying with the order but did not expect the unit to need to run given the state's

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Magazine, 2 April 2026, https://www.powermag.com/doe-has-issued-more-than-40-section-202c-emergency-orders-since-may-2025-heres-an-updated-log/.

[50] Craig Units 1 and 2 are part of the Yampa Project, jointly owned with multiple utility services providers including Tri-State, Platte River Power Authority, PacifiCorp, Xcel Energy and Salt River Project, with Tri-State as the operating entity, see: Tri-State, "U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days," 31 December 2025, https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days.

[51] CMS Energy Corporation, Quarterly Report on Form 10-Q for the Period Ended September 30, 2025, filed with the U.S. Securities and Exchange Commission, page 62, https://d18rn0p25nwr6d.cloudfront.net/CIK-0000811156/2ded8761-a31d-4ff2-8e10-c26bc8a1eaf8.pdf; see also Earthjustice, "Cost of the Trump Administration's Sham Emergency Orders to Force a Michigan Coal Power Plant to Operate Exceed $80 Million," press release, 31 October 2025, https://earthjustice.org/press/2025/cost-of-the-trump-administrations-sham-emergency-orders-to-force-a-michigan-coal-power-plant-to-operate-exceed-80-million.

hydropower resources.[52] Similarly, prior to the DOE's extension of the emergency order at Culley, CenterPoint requested the DOE not to do so and pointed to $20 million in needed repairs and frequent outages during winter months.[53]

The case of Craig Station in Colorado is illustrative of the uncertainty recent emergency orders have injected into resource planning. The DOE order arrived one day before the plant's scheduled retirement, prompting Tri-State and its partners to argue in legal filings that an emergency did not exist and that the order "disrupts a considered resource planning effort" – the Colorado PUC approved the utility's plan to retire the unit in August 2025.[54]

An independent analysis by Grid Strategies estimated that if DOE were to issue similar orders for all large fossil plants scheduled to retire by the end of 2028, the annual cost to ratepayers could reach $3.1 billion, rising to $5.9 billion under a broader scenario encompassing plants not yet on formal retirement schedules.[55] The authors state the following:

> These costs will be broadly distributed across ratepayers in all regions except the Northeastern U.S., with electricity costs increasing by tens if not hundreds of millions of dollars per year in most states. Power plants have been slated to retire because their owners and state regulators have determined they are no longer economic or needed. DOE mandates override those well-informed decisions, inflating electric bills for homeowners and businesses and undermining the competitiveness of U.S. factories and data centers.[56]

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[52] Howland, Ethan, "Coal plant DOE order to stay online unlikely to run given 'flush' power supplies: CEO," 4 March 2026, https://www.utilitydive.com/news/washington-earthjustice-sue-doe-centralia-emergency-order-transalta/813754/

[53] Cook, Amanda Durish, "CenterPoint Asked DOE Not to Extend Emergency Order for Culley Coal Plant," 16 April 2026, https://www.rtoinsider.com/130362-centerpoint-asked-doe-not-to-extend-emergency-order-culley-coal-plant/.

[54] Booth, Michael, "Tri-State Says No Thanks to Federal Orders to Keep Craig Coal Power Plant Open," *The Durango Herald*, 30 January 2026, https://www.durangoherald.com/articles/tri-state-says-no-thanks-to-federal-orders-to-keep-craig-coal-power-plant-open/.

[55] Grid Strategies LLC, "The Cost of Federal Mandates to Maintain Fossil-Burning Power Plants," prepared for Earthjustice, Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club (Washington, DC: Grid Strategies, 14 August 2025, https://www.edf.org/media/independent-report-finds-trump-administrations-orders-keep-coal-fired-power-plants-running.

[56] Ibid.

4. State-level Coal Fleet Case Studies and Data Aggregation

This section establishes the baseline fleet characteristics for the five-state coal sample – Georgia, Kansas, Missouri, North Carolina, and Oklahoma using the U.S. Energy Information Administration's Form 860 final 2024 release, published September 9, 2025.[57] Across the five states, the analysis identifies 50 currently operating coal generating units across 25 plants, totaling 29,590 MW of nameplate capacity, with a fleet-wide average age of approximately 46 years.

4.1 Fleet Summary

Table 3: Operating coal fleet summary by state (EIA-860, year-end 2024)

State	Number of Plants	Number of Units	Total Capacity (MW)	Average Age (Years)
North Carolina	4	9	5,911	47.3
Georgia	2	7	6,172	46.1
Missouri	8	17	9,048	46.7
Kansas	5	9	4,886	47.8
Oklahoma	6	8	3,573	40.4
Total / Avg	**25**	**50**	**29,590**	**45.6***

**Capacity-weighted mean age across the 50-unit, 5-state fleet.*

Three structural patterns emerge. First, capacity is heavily concentrated in a small number of large plants. Georgia is the clearest example: the entire 6,172 MW state fleet is divided between just two plants – Bowen and Scherer – averaging more than 3 GW per plant. By contrast, Oklahoma distributes only 3,573 MW across six plants, averaging closer to 600 MW per plant. This concentration has direct implications for system-level retirement risk: when a small number of large plants exit, the load they served must be

[57] U.S. Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*, final 2024 release published September 9, 2025, https://www.eia.gov/electricity/data/eia860/.

replaced quickly and at scale, whereas a more dispersed fleet permits a more gradual transition.

Second, Missouri stands out as the most coal-dependent state in the sample at the fleet level, with 9,048 MW of operating capacity across 17 units and 8 plants – substantially larger than any other state in the group. North Carolina (5,911 MW) and Georgia (6,172 MW) operate fleets comparable in capacity to Kansas (4,886 MW), but the Carolina fleet is more dispersed across a moderate number of plants while the Georgia fleet is highly concentrated.

Third, average age is tightly clustered for four of the five states (46 to 48 years), with Oklahoma as the lone outlier at 40.4 years – roughly six years younger than the cluster mean. This six-year gap is economically meaningful. A younger fleet has a higher remaining undepreciated book value, larger outstanding stranded-cost exposure for ratepayers, and a longer remaining engineering life on capital-intensive components such as boilers and turbines. It also implies that Oklahoma's regulators and utilities face a different retirement-decision calculus than their counterparts in the other four states: the economic case for early retirement is weaker when the remaining service life is longer, all else equal.

4.1.2 Age Distribution

Table 4: Distribution of operating coal units by age cohort (right-exclusive boundaries; ages as of year-end 2024).

State	<30	30–39	40–49	50–59	60+	Total Units
North Carolina	1	0	2	6	0	9
Georgia	0	1	3	3	0	7
Missouri	2	0	5	10	0	17
Kansas	0	0	6	2	1	9
Oklahoma	0	3	5	0	0	8
Total	**3**	**4**	**21**	**21**	**1**	**50**

Notes: Right-exclusive intervals — "30–39" denotes ages in [30, 40), and so on. "60+" is left-inclusive.

The dominant pattern across the sample is the concentration of units in the 40–49 and 50–59 cohorts: 21 units fall into each, accounting for 42 of the 50 units in the fleet (84 percent). Only three units are younger than 30, and only one – Lawrence Energy Center Unit 4 in Kansas – is older than 60. The operating coal fleet is, in aggregate, approaching or beyond its design life.

North Carolina concentrates two-thirds of its units (6 of 9) in the 50–59 cohort, with only one unit younger than 30 and the remainder in the 40–49 bracket. Missouri shows a similar but more pronounced pattern, with 10 of 17 units in the 50–59 cohort – the single largest age-state concentration in the entire sample. Kansas and Oklahoma diverge: Kansas's age distribution is bimodal, with most units in 40–49 but one unit at 60+, while Oklahoma's eight units cluster entirely in 30–39 and 40–49 with no units older than 50.

Table 5: Youngest and oldest operating coal unit in each state

State	Position	Plant / Unit	In Service	Age (yrs)	MW
North Carolina	Youngest	James E. Rogers (Cliffside) Unit 6	2012	14	910
North Carolina	Oldest	Roxboro Unit 1	1966	60	411
Georgia	Youngest	Scherer Unit 3	1987	39	891
Georgia	Oldest	Bowen Unit 1	1971	55	806
Missouri	Youngest	John Twitty Unit ST2	2011	15	300
Missouri	Oldest	Thomas Hill Unit 1	1966	60	172
Kansas	Youngest	Holcomb Unit 1	1983	43	349
Kansas	Oldest	Lawrence Energy Center Unit 4	1960	66	114
Oklahoma	Youngest	River Valley Unit GEN1	1990	36	175
Oklahoma	Oldest	Northeastern Unit 3	1979	47	473

Two of the youngest units – James E. Rogers (Cliffside) Unit 6 in North Carolina and John Twitty Unit ST2 in Missouri – represent the tail end of U.S. coal construction. Both were commissioned in 2011 or 2012 with full SO_2, NO_x, and mercury controls integrated at the design stage rather than retrofitted. They are supercritical units with substantially better heat rates than the legacy fleet, and their economic profile is materially different from the older units sharing the same plant boundaries or the same state.

At the other extreme, Lawrence Energy Center Unit 4 in Kansas – 64 years old, 114 MW – represents an extreme case of unit longevity. At 114 MW, this single unit is smaller than a single modern combustion turbine, and at 64 years it is well beyond the original design life of 1960s-vintage subcritical pulverized-coal technology. The fact that it remained in operation as of year-end 2024, despite Evergy's announced plans to retire the Lawrence units illustrates the gap between announced retirement schedules and current operating status.

4.1.3 Coal Type Compsition and Fuel Flexibility Implications

Table 6, below, reports the distribution of primary coal fuel types across the five-state sample. The two dominant categories are bituminous (BIT) and subbituminous (SUB); no units in the sample report lignite, waste coal, or refined coal as the primary fuel.

Table 6: Primary coal fuel type by state

State	Bituminous (BIT)	Subbituminous (SUB)	Total Units	SUB Share
North Carolina	9	0	9	0%
Georgia	4	3	7	43%
Missouri	0	17	17	100%
Kansas	0	9	9	100%
Oklahoma	0	8	8	100%
5-State Total	**13**	**37**	**50**	**74%**

The geographic split is sharp. Subbituminous coal – overwhelmingly Powder River Basin (PRB) sourced – accounts for 100 percent of operating coal capacity in Missouri, Kansas, and Oklahoma. North Carolina, by contrast, runs entirely on bituminous coal, with all nine units reporting BIT as primary fuel; this reflects the historical sourcing patterns of Duke Energy from Central Appalachian mines via CSX rail. Georgia is the only mixedfuel state in the sample, with four bituminous units and three subbituminous units. At the fleet level, subbituminous accounts for 37 of 50 units (74 percent) and bituminous for 13 units (26 percent).

The vast majority of these units are structurally locked into single-basin sourcing. Most coal capacity in the five-state sample cannot pivot when its primary basin's delivered price spikes, and the structural rigidity of single-basin sourcing amplifies rather than dampens fuel-cost volatility for the bulk of the fleet.

4.2 Delivered Fuel Costs

This section traces the delivered cost of coal fuel across the 25-plant, five-state coal sample over the eleven-year period 2014–2024, using shipment-level data from the U.S. Energy Information Administration's Form EIA-923 Schedule 2 (Cost and Quality of Fuel Purchases).[58] Costs are reported in both nominal dollars and real 2024 dollars, with real values computed using the Bureau of Economic Analysis implicit GDP price deflator. The analysis surfaces three principal findings.

First, the fleet-wide weighted-average delivered cost of coal declined in real terms from $3.06/MMBtu in 2014 to $2.63/MMBtu in 2024 – a 14 percent real decline over the eleven-year period – interrupted by a 2021–2023 spike that briefly returned costs to near-2018 levels before easing. The real cost of coal therefore did not increase over the past decade for the operating fleet, despite popular framings that conflate price levels with affordability of coal generation. The competitive disadvantage of coal in this period was driven by the relative economics of natural gas and renewables, not by rising coal-fuel cost.

Second, the geographic spread between Eastern bituminous and Western subbituminous deliveries widened the divide between cost tiers within the five-state fleet. By 2024, North Carolina and Georgia plants paid $4.14–$4.51/MMBtu in real terms for primarily Central Appalachian bituminous deliveries, while Missouri, Kansas, and Oklahoma plants paid $1.61–$2.16/MMBtu in real terms for Powder River Basin subbituminous. The roughly 2.5–2.8× cost differential between Eastern-supplied and Western-supplied plants is the single largest source of within-fleet variation in coal economics in the sample.

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[58] U.S. Energy Information Administration, Form EIA-923, *Power Plant Operations Report*, final 2014–2024 annual releases, Schedule 2 (Cost and Quality of Fuel Purchases, published as "Page 5: Fuel Receipts and Costs"), https://www.eia.gov/electricity/data/eia923/.

Third, the 2021–2023 spike was driven by global natural-gas market dynamics rather than by structural coal-supply constraints. Henry Hub natural-gas spot prices jumped from $2.03/MMBtu in 2020 to $6.45/MMBtu in 2022 – a 3.2× increase – pulling delivered coal prices upward as gas-coal switching pressure intensified. Real coal cost peaked at $2.72/MMBtu in 2023 and eased to $2.63/MMBtu in 2024 as gas prices normalized. The episode illustrates the sensitivity of coal fuel costs to gas-market conditions and underscores that fuel-cost volatility for coal is increasingly a function of cross-fuel competition rather than autonomous coal-market dynamics.

4.2.1 Fleet-wide Fuel Cost Trajectory

Table 7 reports the fleet-wide weighted-average delivered cost of coal for each year in the analysis window, in both nominal and real (2024) dollars.

Table 7: Fleet-wide weighted-average delivered coal cost, 2014–2024

Year	Plants Reporting	Total MMBtu (M)	Total Tons (M)	Nominal $/MMBtu	Real $/MMBtu (2024)
2014	24	1,697	91.0	$2.354	$3.062
2015	24	1,712	92.4	$2.269	$2.924
2016	24	1,396	74.7	$2.206	$2.815
2017	23	1,418	75.7	$2.188	$2.745
2018	24	1,293	69.4	$2.140	$2.626
2019	25	1,246	65.9	$2.066	$2.494
2020	24	1,006	53.9	$1.856	$2.209
2021	25	1,097	58.9	$1.910	$2.173
2022	25	1,077	58.5	$2.456	$2.611
2023	25	1,112	60.0	$2.651	$2.717

Year	Plants Reporting	Total MMBtu (M)	Total Tons (M)	Nominal $/MMBtu	Real $/MMBtu (2024)
2024	25	910	48.2	$2.626	$2.626

In nominal terms, the trajectory is approximately flat for the first half of the window – declining gradually from $2.35/MMBtu in 2014 to $2.07/MMBtu in 2019, then dipping further to $1.86/MMBtu in 2020 – followed by a sharp rise to $2.65/MMBtu in 2023 before easing slightly to $2.63/MMBtu in 2024. The headline change over the eleven years is approximately +12 percent in nominal terms.

In real (2024 dollar) terms, the trajectory tells a substantially different story. Real costs decline almost continuously from $3.06/MMBtu in 2014 to $2.21/MMBtu in 2020 – a 28 percent real decline over six years. Real costs then rise to a peak of $2.72/MMBtu in 2023 and ease to $2.63/MMBtu in 2024. The cumulative real change from 2014 to 2024 is −14 percent, indicating that the operating coal fleet's fuel costs were lower at the end of the period than at the beginning, despite the headline-grabbing 2021–2023 spike.

This finding has direct economic implications. A common framing of coal-fleet decline emphasizes "rising coal costs" as a contributing factor in retirements and capacity-factor erosion. The data instead show real coal fuel costs falling for most of the period, and ending the period below their starting point. Coal's competitive position eroded not because coal got more expensive in real terms, but because (i) non-fuel costs increased as the fleet continued to age, and (ii) alternative fuels – particularly natural gas and wind – got cheaper faster. The fuel-cost story for coal is therefore secondary to the fuel-cost story for gas and the levelized-cost story for renewables in any complete account of coal economics in this period.

4.2.2 State-level Real Fuel Cost Spread

Table 8 reports the weighted-average delivered cost in real (2024) dollars for each of the five states across the analysis window. Table 3 summarizes the change from 2014 to 2024.

Table 8: Real ($2024) delivered coal cost by state and year, $/MMBtu

State	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
North Carolina	$4.55	$4.39	$3.99	$3.74	$3.85	$3.35	$2.97	$3.02	$3.86	$4.79	$4.51
Georgia	$3.85	$3.75	$3.54	$3.46	$3.32	$3.19	$3.21	$3.12	$4.13	$4.59	$4.14
Missouri	$2.52	$2.39	$2.34	$2.30	$2.16	$1.96	$1.85	$1.89	$2.05	$1.96	$1.84
Kansas	$2.32	$2.19	$2.16	$2.15	$2.09	$1.94	$1.84	$1.62	$2.00	$1.74	$1.61
Oklahoma	$2.55	$2.55	$2.44	$2.30	$2.17	$2.08	$1.90	$1.97	$2.75	$2.33	$2.16

Table 9: State-level real cost change, 2014 to 2024

State	2014 Real $/MMBtu	2024 Real $/MMBtu	Δ ($/MMBtu)	Real Change (%)
North Carolina	$4.55	$4.51	−$0.04	−1%
Georgia	$3.85	$4.14	+$0.29	+8%
Missouri	$2.52	$1.84	−$0.68	−27%
Kansas	$2.32	$1.61	−$0.71	−31%
Oklahoma	$2.55	$2.16	−$0.39	−15%

Two distinct cost regimes are visible in the data. North Carolina and Georgia, which source primarily from Central Appalachian and Illinois Basin bituminous coal, paid $3.85–$4.55/MMBtu in 2014 and $4.14–$4.51/MMBtu in 2024, with little net real change over the eleven-year period. Missouri, Kansas, and Oklahoma, which source primarily Powder River Basin (PRB) subbituminous coal, paid $2.32–$2.55/MMBtu in 2014 and $1.61–$2.16/MMBtu in 2024, with substantial real declines (15 to 31 percent).

The two regimes correspond to the two principal coal-supply basins serving the U.S. utility sector. The Powder River Basin in northeastern Wyoming and southeastern

Montana produces low-sulfur subbituminous coal at high mine productivity (large surface mines with thick coal seams) and ships it by rail across the Plains. Central Appalachian production has contracted by approximately 60 percent since 2008 as smaller, less productive underground mines have closed and the regional supply curve has steepened.

Coal production in the Appalachian region in 2024 was 157.7 million short tons, down from approximately 390 million tons at the regional 2008 peak.[59] The absence of comparable real-cost decline in NC and GA over the analysis window is consistent with this contraction: as the supply curve has steepened, the marginal delivered cost of Central Appalachian bituminous coal has held its real value despite weakening demand, while the more abundant and operationally more efficient PRB supply has continued to push prices down for Western-supplied plants.

4.3 Capacity Factor and Heat Rate Trajectories

This section traces the operational performance of the 25-plant, five-state coal sample over the eleven-year period 2014-2024, focusing on capacity factor and heat rate as the two principal economic measures of plant utilization and efficiency. Generation and fuel consumption data are drawn from EIA Form 923.[60] Capacity is reconstructed year by year from EIA Form 860, including units that retired or fuel-switched during the analysis window.[61] The analysis surfaces four principal findings:

1. Fleet-wide capacity factor declined from 59.0 percent in 2014 to 33.3 percent in 2024 – a 25.7 percentage-point drop, or 44 percent in relative terms. The decline was effectively continuous through 2020, with a brief partial recovery in 2021 driven by the temporary collapse of natural gas competition and a return to the

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[59] U.S. Energy Information Administration, Annual Coal Report 2024, November 2025, p. 1 and Table 3.1, https://www.eia.gov/coal/annual/. Appalachian coal production in 2024 was 157.7 million short tons, down from 390 million tons at the regional 2008 peak – a decline of approximately 60 percent over 16 years. West Virginia production in 2024 was 79.5 million short tons, down 5.9 percent from 2023; Eastern Kentucky was 10.3 million short tons, down 16.8 percent. The contraction has been driven by competition from natural gas and renewables, declining mine labor productivity in underground Appalachian operations relative to surface mines in the Powder River Basin, and the closure of smaller, less productive mines.
[60] U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," final 2014–2024 annual releases, https://www.eia.gov/electricity/data/eia923/. The form's Page 1 (Generation and Fuel Data) provides plant-level monthly net generation, fuel consumption, and prime-mover/fuel-type classifications. Page 3 (Boiler Fuel Data) provides boiler-level monthly fuel consumption used in this analysis to identify which generators were burning coal in each year.
[61] U.S. Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*, final 2024 release published September 9, 2025, https://www.eia.gov/electricity/data/eia860/.

long-run trajectory thereafter. The 2024 fleet-wide capacity factor of 33.3 percent is roughly half the 2014 baseline.

2. The decline is geographically uneven. Oklahoma fell from 58.8 percent to 19.4 percent capacity factor – a 67 percent relative decline that is substantially the worst in the sample and is driven principally by SPP-region wind displacement rather than fuel-cost or environmental compliance dynamics. North Carolina, Georgia, and Kansas declined 42 to 50 percent in relative terms. Missouri's coal fleet is the only one in the sample to retain capacity factor above 48 percent into 2024, and is the lone resilient state in the sample.

3. The heat rate of the operating fleet has degraded modestly but unidirectionally over the analysis window – from approximately 10,382 Btu/kWh in 2014 to 10,690 Btu/kWh in 2024, a 3.0 percent rise.[62] Most of this efficiency loss occurred in two discrete intervals: 2018–2020 and 2022–2024. The pattern is consistent with two reinforcing mechanisms: increased partial-load operation as plants shift from baseload to mid-merit and marginal duty, and the continued aging of the underlying physical fleet.

4. The 2024 cross-section reveals a sharp three-tier division. Four plants – Labadie (68.8 percent), Sikeston (66.2 percent), Thomas Hill (53.4 percent), and John Twitty (48.7 percent) –operate at capacity factors above 48 percent and account for the bulk of MO's resilience. Thirteen plants run in mid-merit territory at 25 to 50 percent. Eight plants run at marginal capacity factor below 25 percent – including the youngest unit in the sample (Cliffside, NC, 909.5 MW commissioned 2012) at 20.7 percent and the smallest old unit (Lawrence Unit 4, KS, 114 MW commissioned 1960) at 15.3 percent. The eight marginal plants are the most natural retirement candidates regardless of fuel cost or environmental compliance status.

4.3.1 Fleet-wide Trajectory 2014-2024

Table 10 reports the fleet-wide annual operational metrics across the eleven-year window.

[62] An increase in the amount of BTUs required to generate a kilowatt-hour of electricity means that the plant is performing less efficiently.

Table 10: Fleet-wide capacity factor and heat rate, 2014–2024

Year	Coal Nameplate (MW)	Net Generation (M MWh)	Fleet CF (%)	Fleet HR (Btu/kWh)
2014	33,747	174.5	59.0	10,382
2015	33,747	152.2	51.5	10,409
2016	33,698	146.3	49.6	10,382
2017	33,225	141.4	48.6	10,358
2018	32,685	137.2	47.9	10,379
2019	31,541	117.2	42.4	10,438
2020	31,541	96.6	34.9	10,647
2021	31,541	111.7	40.4	10,644
2022	30,650	103.8	38.7	10,620
2023	29,930	88.7	33.8	10,673
2024	30,650	89.5	33.3	10,690

The fleet's coal nameplate fell from 33,747 MW in 2014 to 30,650 MW in 2024 — a 9 percent reduction, reflecting the retirements and fuel switches discussed in Section 1.4. The much larger movement is in net generation: 174.5 million MWh in 2014, falling to 89.5 million MWh in 2024, a 49 percent absolute decline. The capacity-factor consequence is mathematical: more than three quarters of the apparent capacity-factor decline reflects falling utilization of unchanged or only modestly retired capacity, rather than capacity exit.

Three distinct phases are visible in the trajectory. First, 2014 through 2018 is the gas-displacement era: capacity factor declines steadily from 59.0 percent to 47.9 percent as Henry Hub natural gas spot prices remain depressed and combined-cycle gas plants move ahead of coal in dispatch order.[63] Second, 2019 through 2020 is the inflection: capacity

[63] U.S. Energy Information Administration, "Henry Hub Natural Gas Spot Price," annual averages, https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm. Annual Henry Hub spot prices: 2014, $4.37; 2015, $2.62;

factor falls sharply from 47.9 percent to 34.9 percent in two years, with the 2020 collapse partly reflecting COVID-19 demand contraction and partly representing structural decline. Third, 2021 through 2024 is the post-COVID equilibrium: a 2021 partial recovery driven by the natural gas spike (Henry Hub averaged $3.89/MMBtu in 2021 and $6.45 in 2022) gives way to a return to the long-run trajectory by 2023, with 2024 sitting at 33.3 percent.

The fleet's heat rate trajectory tells a complementary story. From 2014 to 2018, heat rate is essentially flat at approximately 10,360–10,410 Btu/kWh — well within normal year-on-year variation for a stable operating fleet. Beginning in 2019, heat rate begins a sustained rise, reaching 10,438 Btu/kWh in 2019, 10,647 Btu/kWh in 2020, and 10,690 Btu/kWh in 2024. The total cumulative deterioration is 308 Btu/kWh, or 3.0 percent of the 2014 baseline.

4.3.2 State-level Capacity Factor Trends

Table 11 reports the capacity factor for each state by year. Table 3 summarizes the change from 2014 to 2024.

Table 11: State-level capacity factor by year (capacity-weighted, %)

State	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
North Carolina	50.4	42.6	41.9	38.4	39.6	35.4	24.5	27.7	23.1	24.1	27.6
Georgia	56.3	51.9	49.7	43.1	46.1	37.0	17.5	25.5	31.1	27.6	32.8
Missouri	66.9	62.9	61.5	67.0	64.4	60.3	53.5	60.4	58.4	45.3	48.3
Kansas	61.0	51.5	48.4	51.7	51.5	40.5	32.4	40.5	40.6	29.0	30.6
Oklahoma	58.8	56.0	41.8	37.3	33.8	24.6	13.8	25.8	26.6	17.0	19.4

2016, $2.52; 2017, $2.99; 2018, $3.15; 2019, $2.56; 2020, $2.03; 2021, $3.89; 2022, $6.45; 2023, $2.53; 2024, $2.19/MMBtu. The shale-gas-driven decline from 2014 to 2020 (a 54 percent drop in real terms) is the principal driver of the gas-coal substitution that displaced coal generation in the dispatch order across most U.S. wholesale markets during the analysis window.

Table 12: State-level capacity factor change, 2014 to 2024

State	CF 2014 (%)	CF 2024 (%)	Δ (pp)	Relative (%)
North Carolina	50.4	27.6	−22.8	−45%
Georgia	56.3	32.8	−23.5	−42%
Missouri	66.9	48.3	−18.5	−28%
Kansas	61.0	30.6	−30.5	−50%
Oklahoma	58.8	19.4	−39.4	−67%

5. Conclusion and Key Considerations for Regulators

This paper has sought to synthesize recent analyses and draw on publicly available data to examine the economic fundamentals underlying current coal plant performance at the national level and in select states. The U.S. coal fleet finds itself once again at an inflection point: electricity demand is increasing for the first time in decades, fuel costs for gas remain volatile, the coal fleet continues to age, and the Trump Administration has signaled in no uncertain terms its desire to resurrect the industry from its managed decline in the name of resource adequacy. Despite declining capacity factors, increased costs, and planned retirements, 2025 saw an 80 million MWh increase in coal generation due to a combination of increasing demand, federal emergency orders which continued the operation of several uneconomic plants, and rising natural gas prices.[64] As regulators in states across the country respond and seek to think proactively about these shifting economic dynamics, they may want to consider the following:

- A key question before regulators is not whether coal will decline further, but at what pace, in what sequence, and at what cost to the ratepayers who will bear the financial consequences of how that transition is managed.

- Given that new coal is not generally under discussion, what is an appropriate approach to retiring or reducing use of existing coal plants and what balance of system resources can maintain system reliability in the face of increased load growth?

- How are current depreciation schedules for coal plants affecting the pace of transition to cheaper clean resources — and are ratepayers bearing unnecessary costs as a result?[65]

- In response to growing electricity demand, are the specific coal assets proposed for continued operation able to deliver reliable, affordable power at a cost that ratepayers should be asked to bear – especially when alternatives exist that are less expensive?

[64] Thomas, Michael. "The US Power Grid Had A Dirty Year in 2025," *Distilled*, 6 January 2026, https://www.distilled.earth/p/the-us-power-grid-had-a-dirty-year.
[65] O'Boyle, Mike and Ron Lehr, "Depreciation and Early Plant Retirements," Energy Innovation, 5 December 2018, https://energyinnovation.org/report/depreciation-and-early-plant-retirements/.

- If renewables combined with long duration storage and paired with energy efficiency are able to cost-effectively serve more morning and evening peaks throughout the year, then regulators may have an opportunity to alleviate some demand pressure on natural gas, which alleviates some cost pressure on natural gas, and has the cascading effect of alleviating demand pressure to keep aging coal assets operating.

- How does regulatory uncertainty affect electric utilities and their retirement plans for coal-fired plants, and does this uncertainty affect investment in other sources of baseload power, firm power resources, or both?

- How should regulators plan for the possibility of future federal regulatory change? Future administrations may reimpose or strengthen emissions standards that could force costly retrofits or accelerate retirements across the remaining fleet. Even under the current administration's permissive posture toward coal, the long-term trajectory of federal environmental policy is uncertain, and planning decisions made today will need to account for the possibility of tighter controls within the operational lifespan of existing plants.

- Should regulators reconsider and, if so in what respects, planned coal retirements in light of ongoing price elevations for natural gas due to rising costs of gas turbines and non-turbine components, and cascading effects of the conflict in Iran and the broader Middle East? What would the economic dispatch of the grid look like if exposure to volatile coal and natural gas fuel prices and increasing capital and O&M costs can be reduced?

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