# MAINTAINING A RELIABLE GRID UNDER EPA'S PROPOSED 111 RULES RESTRICTING POWER PLANT EMISSIONS

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## EXECUTIVE SUMMARY

The summer of 2023 pushed Texas' grid to the brink of power outages. Weeks of record-setting heat made the state hotter than 99 percent of Earth's surface and pushed electricity demand to an all-time high of 81,000 megawatts (MW). In fact, the state set 11 new peak demand records in 2023, but the lights stayed on, in large part because of a rapid influx of new clean energy resources.

Texas, which has long had the most installed wind energy of any state in the country, added 9,000 MW of wind and 8,000 MW of solar since 2021, more than any other state in the same timeframe. These clean energy resources contributed significant reliability value in concert with the existing fleet to meet rapidly growing demand. Wind and solar set generation records during the heat wave, with solar reaching its highest output during the hottest parts of the day, and nearly 3,000 MW of new grid storage kicked in when the sun went down and solar output started falling.

The story of Texas contrasts the stark warnings of looming energy shortfalls from the National Electric Reliability Corporation (NERC), which sets standards and oversees grid reliability nationwide. In testimony to the U.S. Senate Committee on Energy and Natural Resources in June 2023, NERC's CEO identified a core threat to reliability: "Conventional generation is retiring at an unprecedented

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rate…. We must identify new resources to replace retiring generation that provides both sufficient energy *and* essential reliability services….”[1] NERC is right.

While Texas is finding ways to meet new demand and replace existing fossil with clean energy, much of the rest of the country is struggling to add new clean energy resources fast enough to replace retiring assets.

This tension is central to debate over the U.S. Environmental Protection Agency’s (EPA) proposal to limit climate pollution from coal- and gas-fired power plants, which are responsible for nearly a quarter of U.S. greenhouse gas (GHG) emissions.[2] The EPA’s proposed rules recognize the public health imperative to reduce pollution and the new economic reality accelerated by Inflation Reduction Act (IRA) incentives – clean energy is cost-competitive with, or cheaper than fossil fuel technologies. But to meet these standards utilities will have to either retire existing fossil plants, adjust the way they are operated, or retrofit existing fossil plants with carbon capture or hydrogen technologies that need time to scale. Maintaining reliability and enhancing resilience against extreme weather are essential.

We know how to transition towards high shares of renewables reliably and affordably, reducing fossil power reliance even faster than necessary to comply with the EPA’s proposed rule. Several peer-reviewed studies, including some by Energy Innovation, find that mature technologies can deliver energy and capacity when we need it while quickly reducing climate pollution from power sector emissions—as much as 80 percent below 2005 levels by 2030.

Furthermore, technology and standards are evolving quickly to enable wind, solar, and battery resources to replace the essential reliability services that retiring fossil plants provide. The IRA puts America’s power sector on a trajectory to realize this technically feasible vision needed to hit our climate targets while cutting consumer costs by providing tax incentives for clean alternatives like wind, solar, and batteries.

This growing body of evidence has shifted questions about the clean energy transition’s feasibility from, “Can we do this?” to “Can we do this as fast as scientists tell us we must?”

The lesson from Texas is that mature technologies are ready to be deployed at scale, if policies and markets support this rapid transition. While numerous comments exist expressing skepticism about grid reliability under the rules, their worries center around similar themes identified by NERC: The grid must add replacement clean energy and storage resources much faster to account for accelerating fossil retirements. This also implies much faster transmission expansion, and better proactive policies to interconnect new clean resources and reduce congestion costs.

In the current policy environment, this may seem impossible, but the problem is solvable with a smart combination of policy responses. The groups raising reliability concerns, including certain grid operators, state governments, utility trade associations, and individual utilities, can empower our clean energy transition by taking a proactive role in adjusting planning practices and policies to ensure reliability under the proposed rules. Thankfully, the EPA rules provide enough lead time and flexibility to get this right.

Yes, building infrastructure in America is difficult and electricity demand is growing again. But the reliability and resilience value that existing fossil fuels provide must be replaced and then some if we want to transition from harmful fossil fuels and maintain affordable, reliable service in the face of increasingly extreme weather. The EPA rules ensure this remains the central task of utilities, grid operators, and their regulators in the next 15 years.

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## INTRODUCTION

Recognizing the public health imperative to reduce greenhouse gas (GHG) emissions and the advent of mature technologies made more affordable by the Inflation Reduction Act (IRA), the U.S. Environmental Protection Agency (EPA) proposed new limits on coal- and gas-fired power plants, which are responsible for nearly a quarter of U.S. GHG emissions, under section 111 of the Clean Air Act. This report links the EPA's proposal to research demonstrating these rules do not threaten U.S. electricity grid reliability. The report builds upon Energy Innovation's comments to the EPA on its proposed rules for coal- and gas-fired power plants.[3]

The EPA's proposed rules reflect trends that are largely already underway. Coal is on the decline, displaced by cheaper resources—first natural gas, and now renewable energy sources like wind and solar. In 2004, coal generated half of U.S. electricity. In 2022, that number fell to 20 percent, while carbon-free resources including wind, solar, nuclear, and hydroelectric power generated more than 40 percent.[4] Far from the continuously running baseload it once provided, the coal fleet's average capacity factor in 2021 was down to 46 percent.[5] Some regions of the country, such as California and New England, have shifted almost entirely away from coal, and several utilities are already coal-free. This reduction in coal-fired electricity has already created significant health and climate benefits. Moving beyond unabated coal in the U.S. electricity system is the linchpin to cutting GHG emissions at the speed and scale scientists say is required to prevent dangerous climate change.

The EPA's proposed "111 rules" to regulate climate pollution from new and existing natural gas-fired power plants, as well as existing coal-fired power plants, create enforceable requirements to reduce emissions that reflect the changing electricity mix. For existing coal-fired power plants, the rules would regulate a series of subcategories based on planned closure date, with the largest emissions reductions required of plants that intend to operate past 2040.

The Edison Electric Institute (EEI), which represents utilities around the country, states in its comments on the rules "the closure dates reflected in the proposed retirement subcategories broadly reflect the ongoing fleet transition writ large; electric company commitments, costs, and the other factors driving clean energy deployment are all playing a significant role in transforming the sector and reducing emissions."[6] The regulations on new existing gas-fired power plants also create respective subcategories based on generator size and utilization. These place more onerous emission reduction requirements on plants that burn more fuel and therefore produce more greenhouse gas emissions, and less onerous requirements on plants that operate less frequently, but still provide substantial reliability value.

Sections 1 and 2 of this report summarize existing research demonstrating that we need only use existing technologies to reliably plan and operate the U.S. electricity system under the proposed rules. Section 3 provides feasible policy recommendations to get there.

Section 1 covers "resource adequacy"—energy resources' ability to provide enough electricity and capacity to meet demand. We review six studies examining the question of resource adequacy under conditions that align with a power sector that complies with the proposed rules. These studies each explore resource adequacy under a grid with high shares of renewable energy, the retirement of all or most unabated coal-fired power by 2035, and limited expansion of the natural gas system, using at least three industry-standard modeling tools distinct from the EPA's own resource adequacy analysis.

**Section 2** covers "essential reliability services" (ERS)—the maintenance of reliable grid operation in real time. ERS is unlikely to be a constraint because grid operators will have a range of available technologies that can replace the reliability attributes currently provided by fossil plants projected to retire. First, new fossil resources, fossil retrofits, and fossil infrastructure reuse can provide similar replacement reliability attributes. Second, new wind, solar, and storage resources can also provide ERS, in some cases more dependably than their fossil counterparts. Reliability authorities have been conducting promising research and have adequately demonstrated that replacement clean energy resources will be up to the task.

This report is part of the ecosystem of public comments to the EPA's rule proposal, which was issued in May 2023. Comments to the EPA from electric authorities, including four regional transmission operators (RTOs) charged with maintaining reliability over large regions of the U.S. grid, have raised objections over the projected pace of retirements, which they fear could lead to inadequate resources to maintain grid reliability. These same comments acknowledge technical feasibility is less of a challenge than building enough new resources and infrastructure to replace the reliability attributes of fossil plants likely to retire, retrofit, or alter operations in response to EPA rules.

However, these objections raised by industry groups are solvable with the right combination of policy responses, which are covered in **Section 3** of this report. The same industry players raising reliability concerns, including independent system operators (ISOs), individual states, utility trade groups, and individual utilities, can take a proactive role in adjusting planning practices and policies to ensure reliability under the proposed rules. We identify these policy changes along with which industry actors and policymakers can make these changes. The recommendations largely address the fear that energy markets and utilities will not be able to add the right kinds of replacement generation fast enough to maintain a reliable resilient grid, and are summarized here:

1. **Transmission system planners and electricity market operators should go beyond the requirements of recent Federal Energy Regulatory Commission (FERC) orders to modernize interconnection processes and accelerate clean energy deployment.**
2. **RTOs and monopoly utilities should examine the potential for grid-enhancing technologies and use these technologies to quickly increase transmission capacity.**
3. **RTOs and monopoly utilities should proactively plan transmission needs to enable coal retirement. In organized markets, RTOs and utilities should cooperatively align generation procurement plans with reliability needs and transmission plans to reduce costs and ensure timely reliable replacement.**
4. **RTOs should update rules enabling transmission owners to re-use existing interconnection rights at retiring fossil plants to encourage rapid economic replacement. State regulators and utilities should proactively develop generator replacement plans leveraging these interconnection points.**
5. **State regulators should proactively set specific timelines for retirements and retrofits, while undertaking proactive resource planning and procurement that incorporates compliance with the proposed rules.**

Finally, an appendix provides real-world examples of utilities in the U.S. that have embraced the clean energy transition, successfully planning for and completing retirements while adding new resources to attain a coal-free, increasingly renewable electricity system.

### The Proposed Rule and Stakeholder Responses

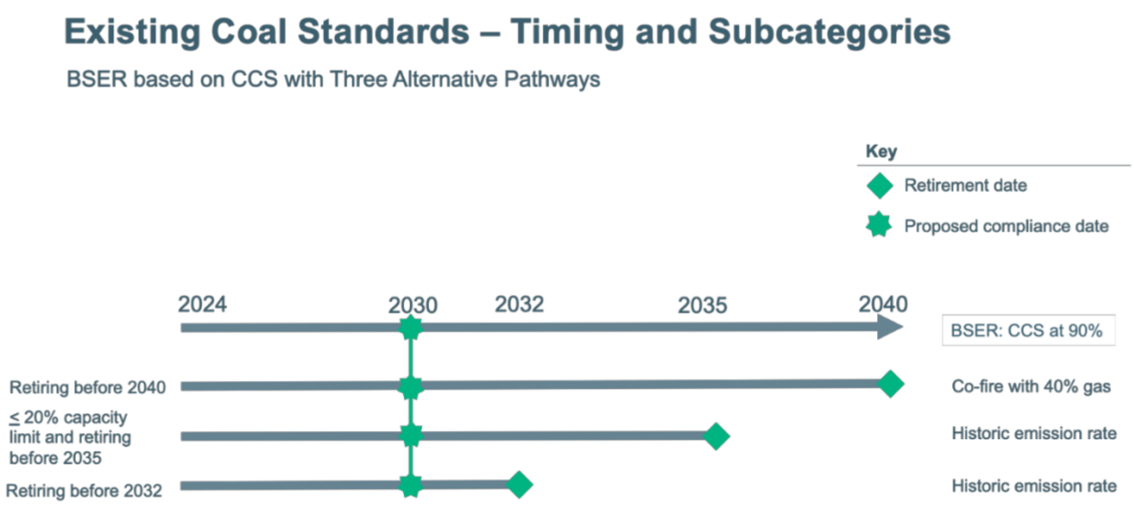
While the EPA's proposed rules are largely representative of the existing transition away from coal, the rules have raised reliability and feasibility concerns from various stakeholders. Industry concerns largely focus on the transitional period between a fossil-dependent grid and a clean grid, as opposed to concerns about whether reducing power sector emissions is feasible. These concerns are valid and important to address—during this transition, the U.S. will need to close or retrofit hundreds of gigawatts of fossil plants while bringing new, clean resources online at record pace.

As the National Rural Electric Cooperative Association (NRECA) observes in its comments to the EPA, recent reliability assessments by the North American Electric Reliability Corporation (NERC) have "pointed to the disorderly retirement of traditional generation (with its inherent ability to provide [ERS] and balance energy reserves) as one of the biggest challenges facing the grid."[7]

The rule has three major provisions, which propose different emissions limits on three distinct power plant types: Existing coal, existing gas, and new gas. For new units, Clean Air Act's New Source Performance Standards apply, which are typically expressed as emissions rate limits for specific technology types – in this case, new gas-fired power plants. For existing units, the EPA establishes best systems of emission reduction for specific technologies as well, but rather than require emissions limits for specific plant types, states implement these via plans that allow for some flexibility to achieve the standards, such as through trading.[8]

The coal rules place emissions limits that would require emissions reductions for all existing coal plants by 2030, with subcategories based on when the plants retire. For plants that retire before 2032, the EPA proposes no emissions limits beyond historical rates. For plants retiring between 2032 and 2035, the EPA proposes to limit operation of these plants to 20 percent capacity factor. For plants retiring between 2035 and 2040, the EPA requires emissions reductions consistent with co-firing coal with lower-emission natural gas. And for plants that plan to run past 2040, the EPA requires emission reductions by 2030 consistent with 90 percent CCS.

**Figure 1. Requirements on Existing Coal-Fired Power Plants by EPA Proposed Rule**



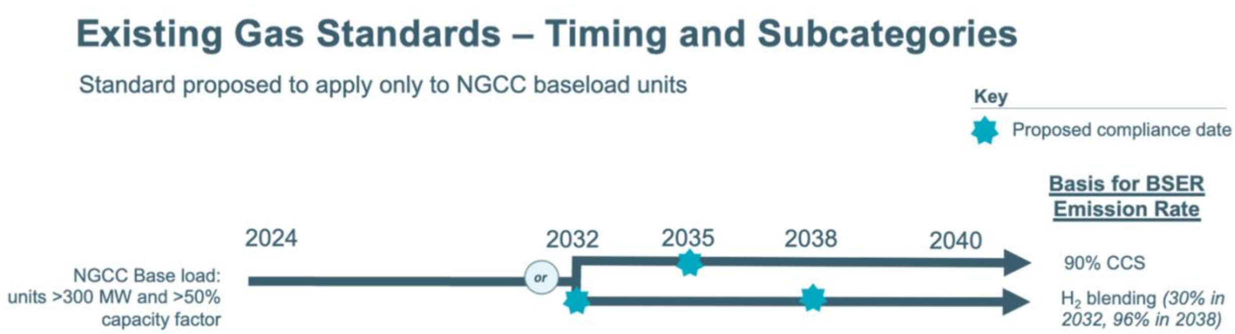

Source: Harvard Law School Environmental & Energy Law Program, 2023.[9]

The proposed rules also include requirements for existing natural gas power plants that have units greater than 300 MW and are operating at capacity factors greater than 50 percent. The EPA has proposed that these units operating as baseload plants must reduce emissions via carbon capture and sequestration (CCS) retrofits or hydrogen blending.

This standard would apply to relatively few plants—only about 70 gigawatts (GW) of the nearly 500 GW of natural gas-fired power plants that would be subject to the rules if they took effect today. Plants could also theoretically avoid the need for costly or risky retrofits by reducing their capacity factors below 50 percent, though comments from ISO-New England point out that this compliance strategy would likely increase overall power sector emissions by shifting dispatch from more- to less-efficient fossil plants.[10]

Going forward, the rules limit the ability of new and existing unabated natural gas plants to provide meaningful increases in energy to replace falling coal use, while preserving their potential role in providing resource adequacy to the bulk electricity system.

**Figure 2. Requirements on Existing Gas-Fired Power Plants by EPA Proposed Rule**



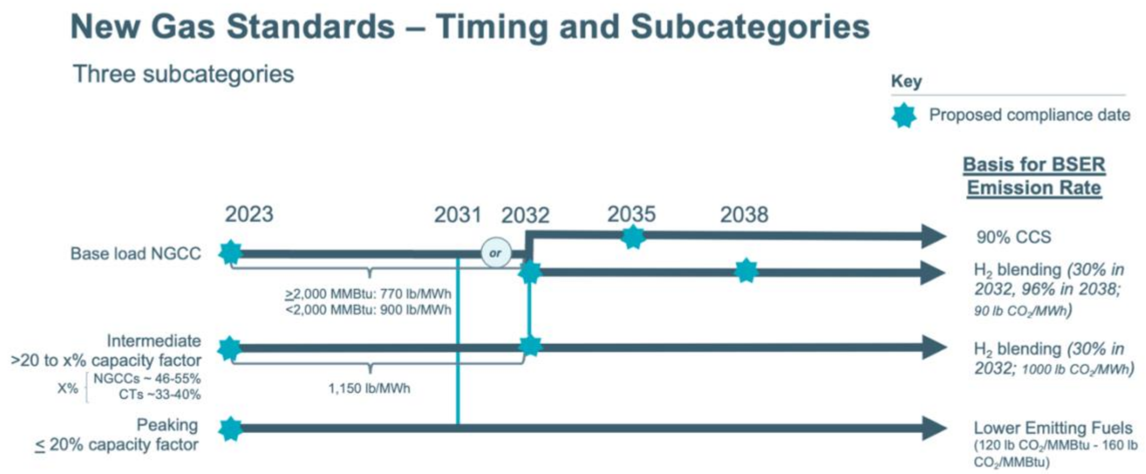

Source: Harvard Law School Environmental & Energy Law Program, 2023[11]

The third and final part of the proposed rules is emissions standards for new gas-fired power plants. This provision provides minimal emissions restrictions on new gas-fired power plants that operate at a capacity factor less than 20 percent—so-called "peaker" plants.

Higher-capacity-factor gas plants—intermediate plants—must reduce emissions in line with a hydrogen blending strategy by 2032, while baseload plants must meet emissions requirements similar to existing baseload gas, on par with 90 percent CCS by 2035, or 96 percent hydrogen blending by 2038.

These rule provisions reflect the power sector transition largely underway today. A few studies, including one by the National Renewable Energy Laboratory (NREL), project that the IRA will drive renewable energy growth rapid enough to undermine the economics of nearly all remaining existing coal plants and eat into natural gas generation's electricity market share. The same studies project minimal adoption of CCS or hydrogen in the power sector in the 2030s, despite significant IRA support for these technologies.

**Figure 3. Requirements on New Gas-Fired Power Plants by EPA Proposed Rule**



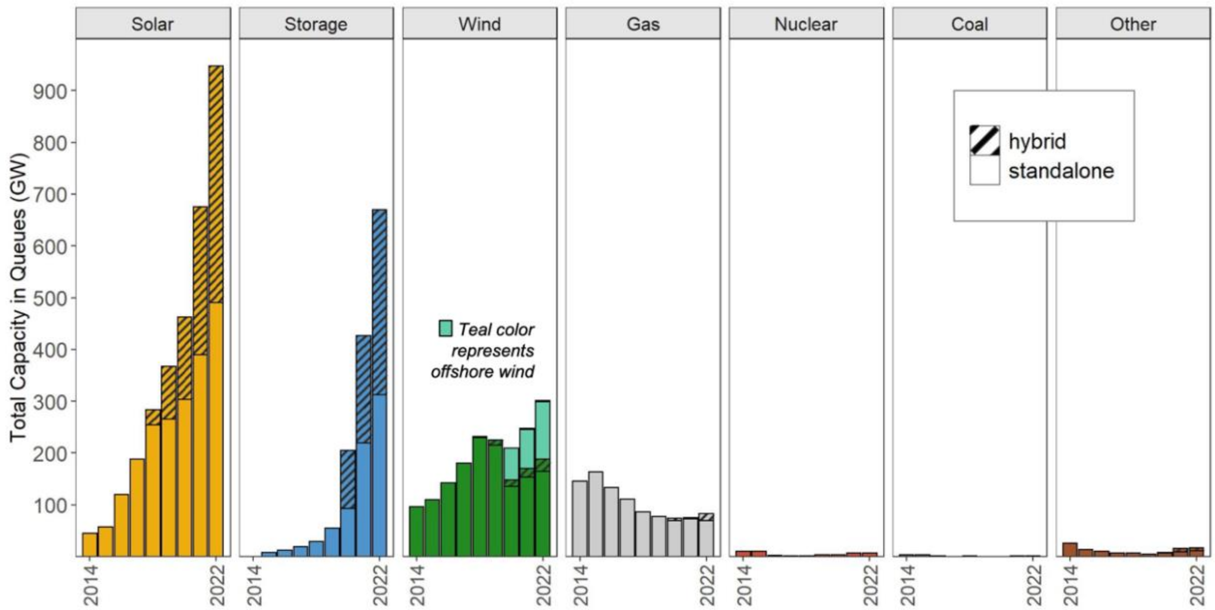

Source: Harvard Law School Environmental & Energy Law Program, 2023.[12]

Though the legality of the proposed rules relies heavily on whether CCS and hydrogen blending represent "best systems of emissions reduction adequately demonstrated,"[13] the rules' reliability impact likely does not. At least six studies summarized in this report demonstrate the industry can maintain resource adequacy as utilities adopt wind, solar, and storage and replace fossil resources in a way that would likely comply with the proposed rules.

This report argues the biggest risk to reliability is not technological, rather whether the institutions that jointly ensure resource adequacy can bring resources online fast enough to compensate for growing electricity demand alongside falling energy and resource adequacy contributions from unabated fossil resources. This risk already exists because the clean energy transition is already underway with or without the EPA rules; the rules merely limit the use of fossil fuels to address reliability.

A managed transition beyond uneconomic or uncontrolled existing fossil power plants would require adding portfolios of clean energy resources to supply ample replacement reliability value ahead of fossil fuel retirements. Nearly 2,000 GW of wind, solar, storage, and hybrid resources are currently seeking interconnection to the grid, representing plenty of capacity to replace retiring fossil, as seen in Figure 4.[14] But greater queue length has slowed down interconnection times, which have doubled on average in the last decade. Institutional responsibility for ensuring an orderly transition is also diffused between regional grid operators, FERC, state regulators, utilities, and state and local permitting authorities.

**Figure 4. 2022 U.S.-Wide Interconnection Queue Capacity by Resource Type**




Source: LBNL Interconnection Queue Study, 2023[15]

History provides a case for optimism: The last time the EPA issued a rule meaningfully limiting GHG emissions from existing power plants—the Clean Power Plan—numerous stakeholders protested on reliability grounds. The same can be said for many other rules addressing conventional air pollution from power plants. However, the power sector achieved the Clean Power Plan's 2030 goal by 2020 without risking reliability as states collaborated in unprecedented ways to propose regional compliance strategies, even though the rule never entered force. The EPA's 111 rules would stimulate similar urgency to reform policies to add sufficient new, compliant resources to compensate for the reliability value of retiring fossil.

These risks are not occurring in a static environment – addressing risk of insufficient deployment is possible but requires new policies and leadership from utilities and RTOs. As these entities consider how to cultivate an affordable, reliable power system under the EPA's proposed rules, they must proactively propose solutions to their regulators, members, and customers that enable investments to best manage costs while maintaining reliability and reducing emissions. They can and should integrate best practices into their own planning and proactively adopt practices that accelerate reliable clean resource additions, responsive to the public health benefits the EPA recognizes in its proposed rules.

Consensus is growing among utilities, analysts, engineers, regulators, and other stakeholders that we can rapidly transition to an electric system dominated by wind, solar, and other clean energy resources due to recent and anticipated technological advances, durable federal support, and cost declines. The next section summarizes a large body of research that demonstrates resource adequacy is achievable under the proposed rules.

## SECTION 1: THE EPA'S PROPOSED RULES WILL NOT UNDERMINE RESOURCE ADEQUACY IN THE U.S. GRID, BECAUSE COAL-FIRED POWER PLANTS AND HIGH-CAPACITY FACTOR NATURAL GAS-FIRED POWER PLANTS ARE NOT NECESSARY FOR RESOURCE ADEQUACY.

The potential for a coal-free, high-renewables U.S. electricity system has been thoroughly assessed. At least six studies have modeled the retirement of all or nearly all coal-fired power generation and rapid addition of renewable resources across the U.S. or individual regions. Even though the EPA predicts modest impacts on the power system from the proposed rules, stakeholders charged with planning and reliably operating the grid argue the rules will likely undermine the U.S. grid's ability to provide adequate power to meet growing demand, especially if retirements are out of sync with replacement.

The EPA's baseline may either over- or under-predict the IRA's impacts, necessitating a look at how other studies predict the future evolution of the U.S. power system and solve for the EPA's predicted rule impacts. In total, the six studies use four modeling tools to reach the same conclusion as the EPA—the U.S. electricity system would likely remain resource adequate even if all unabated coal generation retired by 2035, all while operating existing gas plants at or below their current average capacity factors.

### Resource Adequacy Impact of Proposed Rule on Existing Coal Plants

The EPA's Regulatory Impact Analysis (RIA) forecasts that the proposed Clean Air Act section 111(d) rules will lead to no unabated coal-fired power capacity by 2035. To make this forecast, the EPA relies on the Integrated Planning Model (IPM), one of several industry-standard power sector modeling tools.

The EPA's forecasted rule impact represents a slight acceleration in coal retirement beyond the business-as-usual case, which predicts that all but 30 GW of existing coal retires without the rules by 2035—a roughly 85 percent fall from 2021 levels. The EPA finds this capacity would be supplemented by 12 GW of coal capacity with CCS in 2035 under the rules.[16] The agency released a technical support document laying out its resource adequacy analysis, finding "the implementation of these rules can be achieved without undermining resource adequacy."[17]

Three large U.S. regions have already demonstrated that power systems can be reliably operated with no or very low amounts of coal—New York,[18] New England,[19] and California[20]—lending credence to the idea that grid operators can manage reliable systems without coal. However, the RIA results still question whether the U.S. could retire all *remaining* coal power plants across the country without adversely impacting resource adequacy.

To examine this question, Energy Innovation reviewed six industry-standard studies modeling the retirement of all remaining coal power plants in the U.S. or within a region of the U.S. grid by 2035 or sooner. The studies collectively examine whether and how U.S. electricity systems with no coal-fired generation and much higher penetrations of renewable and other carbon-free electricity can provide adequate energy and capacity when it is needed by the grid to meet growing demand. In industry parlance, this is referred to as "resource adequacy." The studies cover a range of institutions, geographies, models, and timelines; they also differ in assumptions around carbon capture, load growth, and policy drivers.

All six find that systems without unabated coal would meet resource adequacy requirements, with some studies taking a more rigorous approach to reliability modeling than the EPA, including testing their systems' hourly operations over many sample days, weather-years, or stress conditions.

Table 1 summarizes the six studies' results as they compare to the EPA's RIA.

**Table 1. Summary – studies map six pathways to resource adequacy without unabated coal by 2035 or sooner**

| Category | Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions … | Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035 | Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System | Net Zero America – Potential Pathways, Infrastructure, and Impacts | The 2035 Report 2.0 – Plummeting Costs and Dramatic Improve-ments in Batteries Can Accelerate Our Clean Transportation Future | Reliably Reaching California's Clean Electricity Targets – Stress Testing Accelerated 2030 Clean Portfolios | Cleaner, Faster, Cheaper – Impacts of the Inflation Reduction Act and a Blueprint for Rapid Decarbon-ization in the PJM Inter-connection |
|---|---|---|---|---|---|---|---|
| **Institution(s)** | EPA | National Renewable Energy Laboratory | National Renewable Energy Laboratory | Princeton University | University of California, Berkeley; GridLab; Energy Innovation | Telos Energy; GridLab; Energy Innovation | Princeton University |
| **Release date** | May 2023 | 2022 | March 2023 | October 2021 | April 2021 | May 2022 | December 2022 |
| **Geographic scope** | Lower 48 states | Lower 48 states | Lower 48 states | Lower 48 states | Lower 48 states | Western Inter-connection | PJM Inter-connection |
| **Model(s)** | IPM | ReEDS | ReEDS | Energy-PATHWAYS & RIO | ReEDS & PLEXOS | ReEDS & PLEXOS | GenX |
| **Study purpose** | Assess proposed § 111 rules' impact on the U.S. power sector | Assess scenarios achieving 100% clean electricity by 2035 | Assess potential impacts of the IRA and Infrastructure Investment and Jobs Act through 2030 | Assess pathways to reach a net-zero economy by 2050 | Assess impacts and feasibility of high transportation electrification and 90% clean electricity by 2035 | Stress-test reliability in California and the West assuming California meets 85% clean electricity by 2030 | Assess impacts of IRA on PJM system through 2035 + assess how other policies can cut PJM GHGs 80-90% by 2035 (vs. 2005 levels) |
| **All unabated coal retires by** | 2035 (proposed rule case) | 2035 | 2030[1] ("IRA-BIL Mid." Case) | 2030 (all scenarios) | 2030 | 2030 ("WECC Coal Retirement" sensitivity) | 2030 ("IRA and Cap-and-Trade" case) |

[1] Coal generation does not fall to zero in this report but drops to negligible margins in the "IRA-BIL Mid." case by 2030.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **CCS built** | 12 GW coal with CCS, 9 GW natural gas with CCS by 2035 | None for coal; very small (but present) for gas and biomass in some cases | Fossil CCS makes up 1-8% of total electricity by 2030 | None for coal; ~5% of total electricity for gas and biomass by 2035 | None | None | None for coal; up to 14% of total electricity for gas in "IRA and Cap-and-Trade" case |
| **Non-hydro renewable mix**[2] | 29% by 2030; 46% by 2035 | 60-80% wind and solar by 2035 | 40-62% wind and solar by 2030 | >50% wind and solar by 2030 in 4 of 5 cases | 72% wind and solar by 2035 | 75% renewable by 2030 (California) | 34% renewable in 2030; 52% renewable in 2035 |
| **Clean mix**[3] | 52% clean by 2030; 67% clean by 2035 | 100% clean by 2035 | 71-90% clean by 2030 | 70-85% clean by 2030 | 90% clean by 2035 | 85% clean by 2030 (California) | 66% clean in 2030; 78% clean in 2035 |
| **Load growth** | ~5% load growth from 2022-2030; ~11% load growth from 2022-2035 | 66% higher load in 2035 vs. reference case | Up to ~8% load growth from 2023-2030 | ~10-22% load growth from 2020-2030 | ~40% load growth from 2020-2035 | 15% higher load in 2030 in High Electrification case vs. base case | 38% load growth from 2021-2035 (and 41% higher peak demand) |
| **Reliability modeling** | Capacity expansion modeling subject to resource adequacy requirements | Capacity expansion modeling subject to resource adequacy requirements | Capacity expansion modeling subject to resource adequacy requirements | Simulated hourly operations for 41 sample days + assessed long-term operations through 2050 | Simulated hourly operations over 7 weather-years | Simulated hourly operations for 8 weather-years + tested 3 resource portfolios against 7 stressors | Capacity expansion modeling subject to resource adequacy requirements |

The **2022 NREL study, "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035,"** assesses four pathways to achieve a fully clean U.S. electricity system by 2035 while meeting an electrification target where demand grows 66 percent above 2020 levels.[21] The study scenarios include the retirement of all unabated coal-fired power plants by 2035, with 60 to 80 percent of electricity supplied by wind and solar resources, much of the remainder satisfied by hydro and nuclear power, and a marginal amount stemming from natural gas and biomass with CCS. Two pathways also include larger roles for clean hydrogen or new nuclear in the supply mix, respectively. The study finds these electricity systems will be able to meet demand and planning reserve margins during the most constrained hours of the year, even under significant demand growth. However, the ambitious pace of this transition far outpaces the EPA's forecast of the proposed rule impacts.

The **2023 NREL study, "Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System,"** analyzes how the IRA, along with the Infrastructure Investment and Jobs Act, will affect the U.S. power system through 2030.[22] The study finds these policies will contribute to the retirement of nearly all unabated coal generation by 2030, suggesting nearly all of the coal-fired generation fleet is likely to be uneconomic to continue operating before emissions reduction requirements from the

[2] Generally defined as wind (onshore and offshore), solar (front-of-the-meter), geothermal, and biomass.
[3] Generally defined as "renewable" plus large hydropower and nuclear power. Only includes CCS if net emissions are zero (e.g., paired with other actions like direct air capture).

proposed rules take effect.[4] The study also finds renewables would supply 40 to 62 percent of electricity while clean energy would supply 71 to 90 percent of electricity, with the remainder coming from existing unabated natural gas generation operating at lower capacity factors alongside fossil fuels with CCS. The study finds the system will be able to meet demand and planning reserve margins during the most constrained hours of the year, even under significant demand growth.

The **2021 Princeton study, "Net Zero America—Potential Pathways, Infrastructure, and Impacts,"** is a thorough, peer-reviewed academic assessment of five potential pathways to achieve a net-zero carbon U.S. economy by 2050.[23] The study finds each pathway would retire all unabated coal power plants by 2030, with wind and solar supplying upwards of 50 percent of electricity in four of five cases and clean energy supplying 70 to 85 percent of electricity across all pathways. The study finds these systems would be resource adequate based on testing hourly system operations over 41 sample days. Some study scenarios explore the need for bioenergy with CCS to help drive negative emissions that offset hard-to-decarbonize sectors and reduce the need to build large amounts of renewable energy.

The **University of California, Berkeley, GridLab, and Energy Innovation study, "The 2035 Report 2.0,"** examines a least-cost pathway to reach a 90 percent clean electricity system by 2035 while meeting ambitious transportation electrification targets.[24] The study's main policy scenario retires all coal power plants by 2030, builds no CCS projects across all fossil power plants, and includes a high degree of load growth at 40 percent above 2020 levels. This study finds that the system—with much higher penetrations of renewables than the EPA anticipates—would be resource adequate, based on testing hourly operations over seven weather-years. Notably, the study includes more than 300 GW of battery storage to complement renewable resources, without driving up wholesale electricity costs.

The **Telos Energy study, "Reliably Reaching California's Clean Electricity Targets—Stress Testing Accelerated 2030 Clean Portfolios,"** limits its geographic scope to the Western Interconnection but examines reliability more thoroughly than the other studies discussed here.[25] It tests three potential 2030 California electricity systems that achieve 85 percent clean electricity (including 75 percent renewable electricity) against a range of different stressors, including a scenario in which the rest of the West retires all of its coal generation. While California is already a "coal-free" grid, it relies on other Western states for imports, and it sits within a highly interdependent Western Interconnection that still includes significant amounts of unabated coal that will be affected by the EPA rules. The analysis further tests California grid resilience against known stressors such as import limitations, low hydropower availability, faster-than-expected in-state natural gas power plant retirements, and extreme heat. The study finds the systems to be resource adequate in all hours of seven weather-years, including across the range of stress conditions.

The **2022 Princeton study, "Cleaner, Faster, Cheaper—Impacts of the Inflation Reduction Act and a Blueprint for Rapid Decarbonization in the PJM Interconnection,"** limits its geographic scope to the PJM Interconnection power market, assessing impacts of the IRA and other potential policies on this coal-heavy region.[26] The study finds that the IRA paired with a market-wide GHG cap-and-trade policy would eliminate coal power by 2030, resulting in a system that includes 34 percent renewable electricity and 66 percent

[4] The study also includes a "constrained" case that restricts the amount of renewable energy, transmission, and carbon dioxide pipeline and storage infrastructure that the model is allowed to deploy. This case still sees much of the existing coal fleet retire, but much more coal remains on the system relative to the "Mid" case, suggesting EPA rules could help force these units to reduce their GHG emissions or retire.

clean electricity by 2030. The study finds the system would be able to meet demand while retaining adequate capacity reserve margins in each hour.

### Resource Adequacy Impact of Proposed Rules affecting Existing and New Gas Plants

In addition to rules to limit emissions from existing coal-fired power plants, the EPA's rules limiting emissions from gas-fired power plants will not undermine resource adequacy. The transition underway in the power sector reflects a growing share of renewables that will displace the role of coal and baseload gas. What will be needed is flexible resources including storage, gas, demand-response, and transmission that complement renewables as their share of energy and capacity grows.

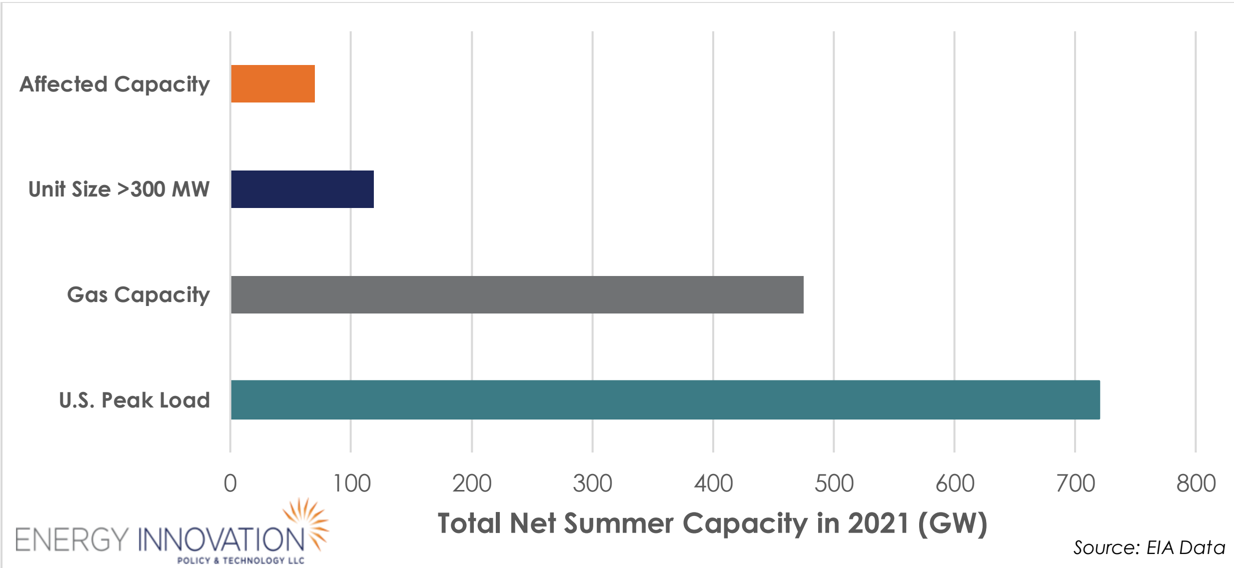
Unlike limitations on existing coal, rules affecting existing gas are less likely to result in retirements, due to limited coverage of the rules and the ability for covered units to avoid regulation by reducing their average output (which could be backfilled by existing exempt units increasing their average output).

Maintaining reliability while reducing emissions in line with the EPA's proposed rules for existing coal and existing gas is technically feasible but may be facilitated by changes to market rules or resource adequacy policies to ensure that gas plants needed for adequacy remain online despite limitations on their operations, including especially capacity factor limitations.

Today the U.S. has 475 GW[5] total gas capacity (excluding expected retirements through 2032), of which 411 GW is combustion turbine (CT) or combined cycle gas turbine (CCGT) technology, according to U.S. Energy Information Administration (EIA) data. Of the total 475 GW natural gas fleet in operation today, we estimate using 2021 EIA data that 70 GW, representing 189 units and 15 percent of total gas capacity, would meet the 300 MW unit size and 50 percent capacity factor threshold today (see Figure 5).

**Figure 5. Gas Capacity Affected by the EPA Proposed Rule for Existing Gas**

[5] These numbers all use Summer Nameplate Capacity, which is reflective of reliability contributions. The operating gas fleet would be 573 GW if using nameplate capacity.




Whether these units would be subject to the EPA regulation under the rules governing existing gas depends on whether capacity factors remain fixed over 10 years. A high-level look at fleet-wide utilization indicates ample room exists for flexible compliance. Gas capacity factors today average roughly 38 percent, well below the threshold of 50 percent that would trigger emissions reductions for existing gas plants.

While the EPA proposes technologies that represent the best system of emissions reduction for covered plants, it will often be cheaper for utilities and power plant operators to comply with this regulation by running higher-capacity-factor units less and lower-capacity-factor units more, thus avoiding regulation under the proposed rules for existing gas. As the grid evolves to accommodate more low-cost renewable energy through 2032, it is reasonable to expect that gas capacity factors could even fall on average, as they did in NREL's examination of the IRA impacts.[27] This average capacity factor may fall further if new natural gas capacity is added to the grid, as many utilities plan to do.[6]

In aggregate, the six studies examined above each rely on existing gas operating at a lower capacity factor compared to today and build little to no new gas to meet demand and resource adequacy requirements in the study period. The six studies examine power systems where clean energy shares grow faster than the EPA anticipates, with each including scenarios that reach at least 78 percent carbon-free generation by 2035. In other words, this research illustrates how grids can remain resource adequate even when gas provides 22 percent or less of total generation in a coal-free system.

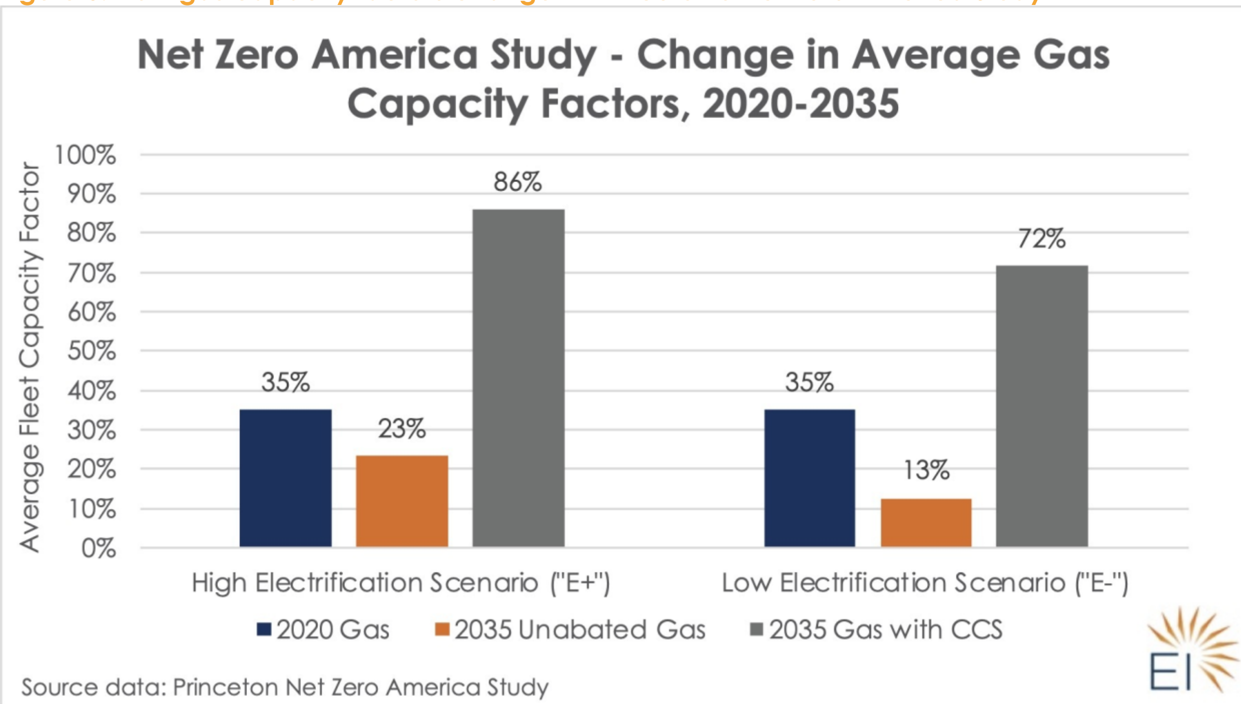
The increased renewable deployment would displace both existing coal generation and natural gas generation, as wind and solar fuels are zero marginal cost, yet each model was able to maintain resource adequacy through the study period despite differences in time and geography.

The Net Zero America study provides data on the 2035 contributions of different technologies under its six core scenarios. The peer-reviewed study finds that few new gas additions are likely even in a high-

[6] The proposed rule on new gas-fired power plants allows for new low-capacity-factor (less than 20 percent) natural gas units of any size to be constructed without the need to blend hydrogen or add CCS equipment. See the appendix, where the utilities examined planned to add more than 30 GW of new natural gas as part of their transition away from coal.

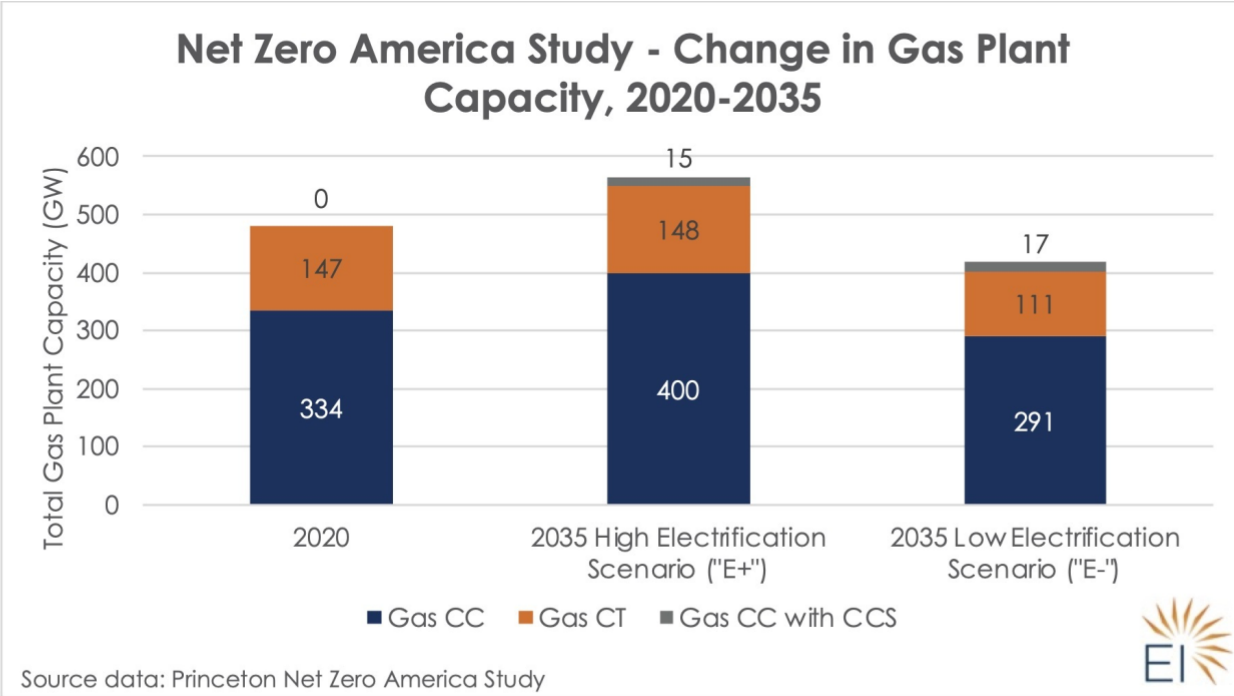
electrification scenario and that the grid can maintain resource adequacy relying on the existing gas fleet operating at much lower average capacity factors.

**Figure 6. How gas capacity factors change in Princeton's Net Zero America Study**




The two scenarios shown below represent low- and high-end load growth assumptions reaching 80 to 90 percent carbon-free generation by 2035. Average gas fleet capacity factors fall below 25 percent in each scenario, while a small number of new gas plants with CCS operate as baseload power plants. It is worth noting that this study builds much less battery storage than the others examined in this report.

**Figure 7. How national gas capacity changes in Princeton's Net Zero America Study**




The 2035 Report 2.0[28] maintains resource adequacy in a 90 percent carbon-free generation mix without building new gas power plants and while significantly reducing the utilization of existing gas. Average gas fleet capacity factors in the 2035 Report 2.0 would fall from 38 percent today to roughly 16 percent in a 90 percent clean electricity future. Regulations with 50 percent capacity factor minimums to trigger emissions reductions therefore would likely have miniscule, if any, effect on resource adequacy in a high-renewables grid.

In another example, the GridLab, Telos, and Energy Innovation study[29] of California's resource adequacy with a higher share of renewables resulted in a similar dynamic of decreasing utilization of existing gas. In that study, the fleetwide capacity factor for all types of natural gas-fired power plants is approximately 10 percent in an 85 percent clean grid in 2030, with CCGT units at 15 percent, and steam turbine and CT generators at less than 2 percent each. Few units in this context would be affected by the proposed rule for existing gas units, and if any were, ample headroom exists to shift gas generation between low- and high-capacity-factor units to handle any concerns associated with emissions reduction requirements that might undermine resource adequacy.

### Considering the rules' combined impacts on resource adequacy

The aggregated studies presented here show resource adequacy is both feasible and likely even if the U.S. electricity grid transitions faster than the EPA anticipates and could happen in both its baseline and proposed rule scenarios.

Analyses by NREL and Princeton, for example, anticipate that the IRA will usher in coal retirements and accelerate wind and solar deployment faster than either of the EPA's scenarios. The variation in scope should also increase confidence—studies focusing on the West and PJM confirm these results in specific regions. As noted above, the EPA's RIA relies on IPM, which represents just one modeling tool, and other industry-standard tools confirm the EPA's assessment that a grid with no unabated coal generation can and will remain resource adequate if clean resources are permitted to replace coal at a pace consistent with or faster than the EPA's analysis.

National utility-scale wind and solar additions from 2020 to 2022 averaged 25 GW annually, along with 2 GW of battery storage, according to EIA data. The EPA forecasts that under its proposed rules, annual wind and solar additions would be about 20 GW from 2023 to 2028, and 40 GW from 2028 to 2040. The EPA's forecast represents a modest upward adjustment in pace to maintain resource adequacy that would likely not stress the overburdened interconnection process or slowly expanding regional transmission grid.

Furthermore, falling costs for renewables and storage coupled with sustained policy support from the IRA will help overcome those barriers, accelerating renewables deployment over time. If renewables cannot come online as fast as these studies predict, or even slower than the EPA forecasts, the proposed rules still allow other options for grid operators and utilities, including new peaking gas turbines, storage, and CCS retrofits that can economically fill the resource adequacy gap while complying with the standard.

While the EPA's RIA forecasts the elimination of unabated coal by 2035, it does not forecast that the proposed coal rule will materially impact nuclear, hydro, and non-hydro renewable energy generation relative to the baseline scenario. The IRA helps ensure this will be the case by providing support for existing nuclear.[30] Instead, the EPA modeling predicts the rule will lower power generation from unabated coal, while increasing generation from coal with CCS, gas, and gas co-fired with hydrogen—creating a system with 46 percent renewables and 67 percent clean electricity by 2035, with 12 GW remaining coal with CCS.

Though these national numbers are encouraging, the trends will be amplified and potentially difficult to maintain in local grid areas or regions that have high concentrations of unabated coal, face high load growth, and lack institutions up to the task of adding new resources quickly. As discussed in Section 3 of this report, RTOs and utility action as well as regulatory policy each largely influence whether resources can come online fast enough. For example, transmission interconnection and transmission capacity are barriers to rapid deployment of renewables, as are policies and lack of coordination between regional and state regulators and utilities. Supply chain issues pose other short-term risks to wind, solar, and storage development, and have led some utilities to push to delay planned coal retirements.[31]

However, these are institutional rather than technical barriers to reliability under the proposed rules. The pace of transition contemplated by the six studies using diverse modeling tools greatly exceeds what the EPA forecasts will be necessary to comply with the rules.

Another factor complicating the resource adequacy assessment in some areas is uncertainty around load growth from three areas: policy- and market-driven electrification (including hydrogen electrolysis), onshoring of manufacturing, and growth in data center demand driven by artificial intelligence computation. Data center growth is likely to be concentrated in areas where cheap real estate and grid access are both available, and data centers can move to where these conditions are met.

Recent developments in Northern Virginia exemplify the risk that can undermine the pace of retirements if new resources cannot come online even faster. PJM forecasts 4 to 5 percent annual load growth in the Northern Virginia Zone in the next 10 to 15 years,[32] leading Dominion Virginia to postpone many data centers' interconnection requests to 2026.[33] As electrification ramps up, large new electrified loads such as trucking fleet high-voltage charging stations might encounter similar issues if the grid is not proactively planned to accommodate them. Because we have not observed the IRA's impacts on manufacturing and electrification, utilities may be hesitant to retire fossil assets or may build extra reserve margins into their plans to account for this uncertainty.

Despite potential load growth, the incremental impact on new resources should still be concentrated in specific areas, and numerous tools, including the addition of new gas capacity, exist under the proposed rules to address them. Utilities and RTOs should also consider solutions such as behind-the-meter generation and storage, demand-side management and efficiency, and better and more coordinated state and regional transmission planning to manage these challenges as they arise.

The EPA's power system modeling under its proposed rule also reflects that the power system is already in transition. The rules pose relatively minor additional challenges to resource adequacy in this context, by limiting the emissions associated with reliability solutions. We are deep in the process of planning for a system that is lower in coal and gas generation, and higher in renewable penetration, and this work will continue regardless of EPA rules.

In aggregate, the EPA modeling and the studies using different industry-standard models all found that their cleaner electricity mixes meet resource adequacy needs across a wide range of weather conditions and geographic scopes, bolstering the EPA's finding that its proposed rules will not threaten resource adequacy.

## SECTION 2: THE EPA'S PROPOSED RULE WILL NOT UNDERMINE REAL-TIME OPERATIONAL RELIABILITY BECAUSE AMPLE OPPORTUNITIES EXIST TO REPLACE THE ESSENTIAL RELIABILITY SERVICES PROVIDED BY FOSSIL PLANTS THAT WOULD RETIRE.

Resource adequacy and system stability during real-time operation are critical components of grid reliability. Power systems need to maintain constant frequency and resources to stabilize voltage during both normal operation and unexpected events.

Reliability authorities and power system operators have identified several ERS that help achieve stability. ERS comes from a combination of transmission infrastructure, power plants, and demand-side resources. Because the EPA projects no unabated coal-fired generation by 2035 under its proposed rule, some grid operators, utilities, and customers are concerned whether stable, reliable operations can be maintained without these resources. To maintain grid reliability, the ERS provided by uncontrolled coal plants must be replaced by new or other existing grid assets.

In their comments to the EPA on the proposed rules, several grid operators highlighted these issues, with the Southwest Power Pool (SPP) expressing concern "that an impactful risk to electric system reliability is introduced with every incremental conventional resource retired until such time as appropriate levels of accredited and [ERS] attributes are available as needed to maintain regional reliability."[34]

Fortunately, several other types of generators and other grid assets are projected to continue operating under the proposed rule, providing the same level or better of ERS compared to coal-fired power plants. These include coal-fired power plants with CCS, new natural gas-fired generation that complies with EPA rules, nuclear power plants, hydro power plants, renewable energy power plants including wind and solar, demand-response, and battery storage.

Grid operators acknowledged this potential but expressed apprehension that the technology necessary to provide these services may not be ready in time, commenting that "new technologies and industry practices are developing to enable the integration of significant inverter-based generation that provide needed [ERS]. But, the [MISO, SPP, ERCOT, and PJM] are concerned about a scenario in which, similar to that stated above, needed technologies are not widely commercialized in time to balance out large amounts of retirements."[35]

However, grid-forming inverter technology has been used for decades in microgrids and on small islands, and recent advances are making possible the use of multiple grid-forming inverter-based resources (IBRs) in larger grids to support reliable system operation where there are high shares of IBRs and retirements of conventional generation.[36]

And years of innovation by 2035 will produce further technologies to help provide the ERS that coal currently provides. Therefore, ample resources are available today to help maintain and enhance system stability through a transition away from unabated coal, with more resources coming soon.

Grid regulators are also actively working and are vested with adequate authority to ensure continued operational reliability. NERC is the federally sanctioned reliability organization for the U.S. and helps monitor ERS while conducting research to ensure that resources contribute what's needed to maintain reliability. NERC has been convening various working groups to address IBRs and their capabilities for many years. NERC's efforts began with the Essential Reliability Services Working Group in 2014;[7] this group has evolved into the Inverter Based Resources Working Group, made up of industry experts from North America. NERC's work with this group led to NERC guidelines on grid services and IBRs like wind, solar, and battery storage.[8] In 2022, FERC opened a rulemaking docket for IBRs and solicited industry comments.[37] The resulting final rule directed NERC to develop reliability standards for IBRs that would gather data, validate performance, and eventually require IBRs to begin providing reliability services.[38]

As the industry adapts to the increasing levels of IBRs on the grid and fossil resource retirement, it has become clear that concerns about the ability to maintain system reliability—in particular grid reliability services—are somewhat misplaced. The capability of IBRs to supply these services has been shown to surpass the performance of traditional resources.

### Essential reliability services

The ERS required to maintain grid stability include disturbance ride-through, inertia, reactive power and voltage support, fast frequency response, primary frequency response, automatic generation control, and dispatch/flexibility.[39] These services work on different timescales to stabilize frequency at 60 Hertz, to control voltage and ensure contingency events do not destabilize the voltage or frequency of the bulk

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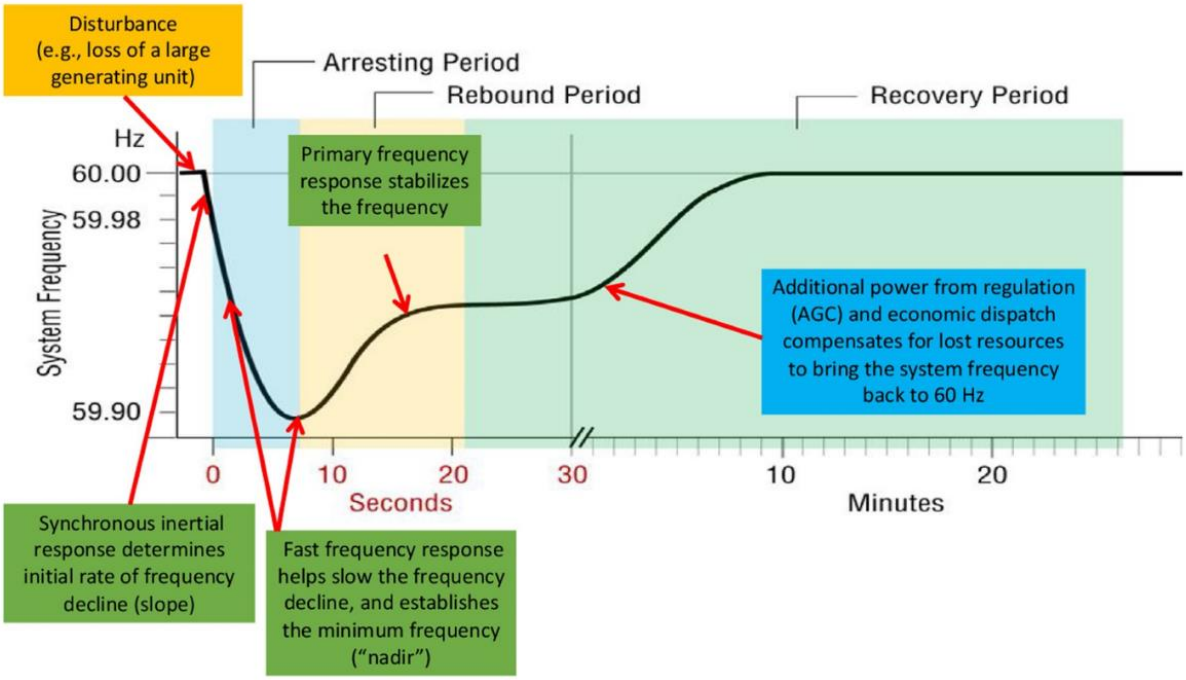
[7] See generally Essential Reliability Services Working Group website: https://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

[8] See generally https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx.

electricity system, causing cascading outages. Figure 8 illustrates how ERS combine in a contingency event to restore the frequency of the bulk electricity system.

**Figure 8. An example of how ERS stabilize frequency over the course of a grid disturbance and recovery**




Source: Milligan, "Sources of Grid Reliability Services," 2018[40]

The following are the primary types of ERS:[41]

- *Disturbance ride-through*: A grid disturbance occurs when a transmission line or generator unexpectedly goes offline, causing the voltage to vary. Typically, this disturbance does not threaten the stability of the grid on its own, but if other generators go offline because of voltage swings, cascading outages can occur. Many generators are therefore designed to continue operating if voltage fluctuates within a certain window.
- *Inertia*: Inertia is the stabilizing property of the grid historically provided by large, heavy spinning turbines that resist changes to frequency. Inertia keeps frequency from dropping too quickly when a grid disturbance occurs.
- *Reactive power and voltage support*: Reactive power and voltage control is the reliability service that can help maintain voltage within the proper range and return voltage to its normal operating level after an initial disturbance has occurred, or if voltage is fluctuating significantly during normal operation. To keep voltage within its nominal range and perform this service, generators or other resources can inject more or less reactive power into the grid to raise or lower voltage.
- *Fast frequency response*: After a contingency event, frequency begins to drop at a rate determined by the inertia in the system, as seen in Figure 8. However, inertia cannot stop frequency decline on its own. Fast frequency response is the reliability service that can both slow frequency decline and stop it and is central to the "arrest phase."

- *Primary frequency response*: Once frequency has stopped dropping, frequency stabilization occurs in the "rebound phase" that returns frequency to its normal operating level. This reliability service is called primary frequency response, and it is an automatic response to dropping frequency that occurs within several seconds of a disturbance by increasing power output.
- *Frequency regulation*: Frequency regulation is a part of the minutes-long frequency "restoration phase," and a reliability service all on its own. To regulate frequency, generators respond to computer signals at periodic intervals of several seconds to maintain frequency within its nominal range. This is also called automatic generation control, and it is slower than both fast and primary frequency response.
- *Dispatchability/flexibility*: Dispatchability or flexibility refer to a resource's ability to respond to both expected and unexpected changes in generation or load. Often, this means a resource's ability to ramp output up or down over a short timeframe.

### New and existing resources can provide superior ERS compared to coal-fired power plants

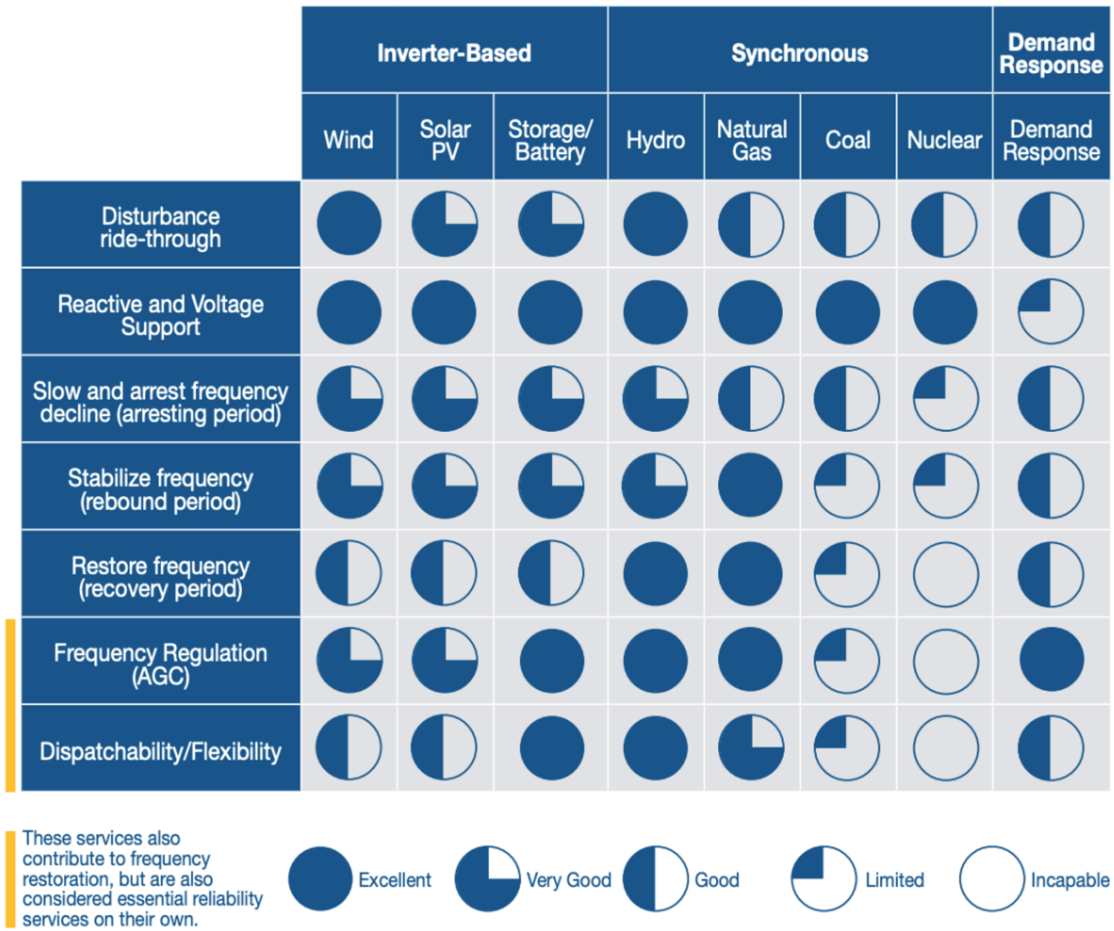
As seen in Figure 9, all mature resources on the grid today provide some degree of ERS, but with different characteristics. Ultimately, ERS is not a single-resource problem: Whether they are sufficient depends on the portfolio and location of resources, which include controls that are embedded within the transmission system itself, as well as individual generators.

Coal-fired power plants provide dependable disturbance ride-through and reactive power and voltage support—services that inverter-based and synchronous resources can all provide. The EPA's proposed rules allow for continued use of coal-fired power plant infrastructure to provide ERS, in at least two ways. First, the EPA contemplates that coal plants can and will be retrofitted with CCS to comply with the standard. Coal plants can also be retrofitted to serve as synchronous condensers, wherein the generators are disconnected from the coal boiler and steam turbine and instead are powered by the grid to spin and provide inertia, reactive power, and voltage support, without generating electricity or burning fuel onsite.[42] It may also be possible to site thermal batteries at coal-plant sites and use the steam to provide power and ERS.[43] In other words, all ERS of a coal-fired power plant need not be lost due to a projected decrease in coal-fired electricity.

Regardless of whether coal plants are operated as synchronous condensers to continue providing grid services, new resources that are IBRs will have the ability to provide these grid services. As long as thermal plant retirements are compensated for by new IBRs, the overall supply of grid services can be maintained with proper planning during the transition.[9]

**Figure 9. ERS provided by different grid assets**

[9] Another prerequisite for reliability is that rules governing the deployment of IBRs allow or require them to provide grid services. This prerequisite has largely been met by a combination of NERC's working groups and the FERC rulemaking described above. New ancillary services products may help ensure adequate ERS are available in competitive markets.




Source: Milligan, "Sources of Grid Reliability Services."

First, the proposed rules contemplate continued operation as well as new construction of natural gas-fired power plants under several circumstances. As previously stated, the rules either limit the amount of energy that an existing gas plant provides over the course of a year to 50 percent of its potential output or require emissions-reducing technology, including hydrogen blending and CCS. Either option would allow gas plants to continue providing many ERS. In particular, the rules place few limits on new gas-fired peakers, which are highly flexible and operate at low-capacity factors. Newer combustion turbine peaker plants are designed to ramp up and down very quickly, which means they provide good, very good, or excellent grid services across all ERS categories identified in Figure 9. However, because they run infrequently, they would not provide system inertia most of the time. The rule does also allow higher-capacity-factor gas units that comply with proposed emissions limits that can better contribute to system inertia.

The proposed rules also do not affect emission-free hydro power plants or nuclear power plants, which are able to ride through disturbances, and which provide reactive power and voltage support services similar to coal plants. Hydro power plants provide very strong frequency support, and both hydro and nuclear plants provide significant system inertia.

Finally, the proposed rules also do not affect inverter-based clean energy resources, which can provide ERS at levels that support reliable grid operation, when the proper power electronics and controlling software are used. Renewable resources such as wind and solar energy, along with battery storage, are connected to the grid via electrical inverters, which convert the DC power at the resource to the AC grid. These inverters are highly programmable and customizable, resulting in devices that can provide ERS. These inverters are able to ride through disturbances, as is now required by NERC.[44]

They can also provide even faster frequency responses than synchronous generators, which means that while they do not provide as much inertia, less inertia is needed to maintain stability when wind and solar are available to increase output.[45] IBRs, especially wind turbines, can also provide "synthetic inertia" to the grid, by programming the inverters to respond to changes in frequency similar to a spinning mass such that they increase power output in response to a frequency decrease.[46] Battery storage, which is both dispatchable and inverter based, also provides excellent ERS.[47] [48]

RTOs are already taking on these challenges. In 2021, MISO evaluated the feasibility of maintaining operational grid reliability, in addition to energy and resource adequacy, of 30-50 percent renewable penetrations in the Renewable Integration Impact Assessment (RIIA).[49] MISO found that the complexity of operating the grid does increase significantly when renewable penetration is greater than 30 percent. However, the "RIIA concludes that renewable penetration beyond 50 percent can be achieved" with transformative thinking and coordinated action. The EPA projects 46 percent penetration by non-hydro renewables in 2035 in its more stringent proposed rule scenario—within the technical feasibility range analyzed by MISO. RTOs recognize markets may need to be developed to ensure new and existing resources are adequately compensated and incented to provide ERS embedded in the existing coal fleet, meaning that utilities, RTOs, and NERC likely have more work to do to map out an orderly transition.[50]

The EPA designed the proposed rules to allow utilities and system operators the flexibility they need to maintain and enhance reliable grid operations. Ensuring ERS through the energy transition is not a new topic, and NERC—which ultimately bears this responsibility—has already done substantial work on this topic, setting performance-based requirements for these grid services.[51]

Despite comments to the contrary, RTOs and NERC continue to succeed at their reliability mandate as the system changes. With the suite of resources available under the proposed rule, continued grid stability is eminently achievable.

## SECTION 3: NEW POLICIES AND ACTIONS BY INDUSTRY PLAYERS RESPONSIBLE FOR RELIABILITY ARE NEEDED TO PROMOTE A MANAGED TRANSITION THAT ADDS NEW RESOURCES AT PACE WITH RETIREMENTS.

Managing the clean energy transition to ensure reliability and affordability does not fall to a single entity in the U.S. Instead, a multitude of different actors including utilities, regulators, and system operators are each partly responsible, often with limited jurisdiction. Utilities are responsible for planning their future resource mix, and regulators are responsible for ensuring that their plans meet reliability standards. System operators, which may include RTOs in some regions, are responsible for planning the transmission system.

They also operate the grid in real time and can operate markets to ensure there is enough generation capacity availability and incentivize generators to provide needed grid services. These entities need to work together to ensure consumers have continuous electricity across the country.

Ironically, some of the most visible authorities that raise concerns about the pace of change are the entities that have the most influence over this pace. For example, RTOs, which control the interconnection study and cost allocation process, highlight that they could face worsening reliability challenges as coal plants retire. Joint comments from SPP, Electric Reliability Council of Texas, Midcontinent Independent System Operator (MISO), and PJM cite the inability to bring sufficient new generation online as a primary cause of looming resource adequacy shortfalls that they believe the EPA rules would accelerate.

However, with reforms recently finalized by FERC as part of Order 2023, RTOs have a new mandate to accelerate the interconnection process and stimulate more efficient additions of new, clean resources to manage reliability concerns as retirements continue.[1052] RTOs and utilities within FERC's jurisdiction can focus on reforming the interconnection study and cost allocation process even beyond that required by the new rules, greatly improving the chances that enough resources from the queue can enter service in advance of looming retirements.

While research indicates a reliable transition is technically feasible, implementing that transition falls to a fragmented set of overlapping authorities at the state, regional, and federal levels. The EPA offered a series of studies aimed at demonstrating the feasibility of compliance with its proposed rules, but no national study can or will capture unique local and regional reliability constraints for which planners must account and manage.

As the Electric Power Research Institute notes in its comments, "the incremental impacts on reliability and resource adequacy of power system decarbonization are ambiguous and vary by region and system, policy design, metrics, and assumptions about the counterfactual baseline (for example, forced outage rates over time, correlated outages during extreme weather events, transmission expansion), especially because these changes may impact both resource additions and retirements."

While the EPA can devise regulations aimed at reducing air pollution and GHGs, it does not have the authority to manage every step of the transition itself, nor would any national-scale modeling study capture local reliability constraints and solutions that regions and states must implement to comply. That duty will fall to states, utility regulators, utilities, and grid operators, who will each be responsible for their respective regions.

As discussed in the appendix, more than 20 utilities representing about 20 percent of load have examined the feasibility of retiring coal by 2035 or sooner while replacing it mostly with new clean energy resources and have found ways to manage the pace of transition reliably. The same can be said for ISO New England, California, and New York, which are already entirely or very nearly coal free and represent an additional 12.5 percent of U.S. demand.[11]

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[10] Changes to the interconnection process include consolidating interconnection studies across multiple projects to decrease the number of studies and share costs, as well as implementing time limits for studies and financial commitments from developers.

[11] Supply chain disruption in the wake of the pandemic has also affected renewable energy procurement in recent years. Largely due to these issues, 2022 renewable installations were down. However, in the medium to long term, these issues are expected to

The issues plaguing the interconnection and procurement processes in the RTOs and utilities worried about system reliability can be managed if these entities take a proactive approach or, as in the case of New York, New England, and California, if they face stringent pollution regulations that prompt reforms. Several policies can help RTOs and utilities prepare for the clean energy transition that the EPA rules are projected to incrementally advance while ensuring grid reliability:

**Adopt a connect-and-manage interconnection process to accelerate clean energy deployment.** The recent FERC Order 2023 initiates several reforms to the interconnection process that can help alleviate ever-increasing interconnection costs and burdens on generators, which spend four to five years in the queue on average with decreasing success rates.

Currently in most parts of the country, when resources try to connect to the grid, the grid operator determines what grid upgrades are necessary to guarantee a certain level of access to the grid. This is commonly known as "invest and connect." FERC requires RTOs to evolve this approach to serve projects that are more likely to be ready, instead of a first-come, first-served approach. Order 2023 also establishes enforceable study timelines and requires a cluster study approach to help better share costs between multiple beneficiaries in the queue. But in many ways, the proposal does not overcome the fundamental issue that transmission planning occurs within the interconnection process, and not prior to it.

One reform for RTOs to consider that goes beyond what is required is a "connect and manage" approach to interconnection. Texas has uniquely succeeded connecting new resources, bringing *three times* the clean energy capacity online in 2021 as PJM using this approach.[53] Here, developers take on risks of curtailment as they are not guaranteed a certain level of use of the transmission system, but the only upgrades they need to pay for are those that are needed to physically connect them to the grid. The system then relies on congestion market signals to build new transmission to accommodate these new resources in the long term. To promote grid reliability and respond to consumer and utility demand for new resources, RTOs should make this approach more accessible and a standardized option for new resources, and pair it with proactive planning to ensure resources can contribute reliability value as the resource mix changes.[12]

**Examine the potential for and use grid-enhancing technologies to quickly increase transmission capacity.** Building is not the only way to add new transmission capacity to the grid. In fact, use of grid-enhancing technologies (GETs) and upgrading lines using advanced conductors can up to double the potential to add renewable energy capacity on existing lines.[54] GETs include dynamic line ratings, which allow lines to carry more capacity under certain conditions, and power flow controllers, which can push or pull power across lines that have more available capacity when others are highly congested. However, monopoly utilities may lack incentive to deploy GETs because they are cheaper than building new assets, and monopoly utilities charge customers based on their investment.

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resolve. Already, 2023 is expected to see significant rebound in renewables installations. See "Executive Summary – Renewable Energy Market Update," IEA, June 2023, https://www.iea.org/reports/renewable-energy-market-update-june-2023/executive-summary.

[12] Many of these potential solutions are discussed as part of Commissioner Alison Clements' concurrence to FERC Order 2023. FERC, "Order 2023 - Improvements to Generator Interconnection Procedures and Agreements," Concurrence of Commissioner Alison Clements. Pub. L. No. RM22-14–000, 184 FERC ¶ 61,054 (2023), https://www.ferc.gov/media/e-1-order-2023-rm22-14-000.

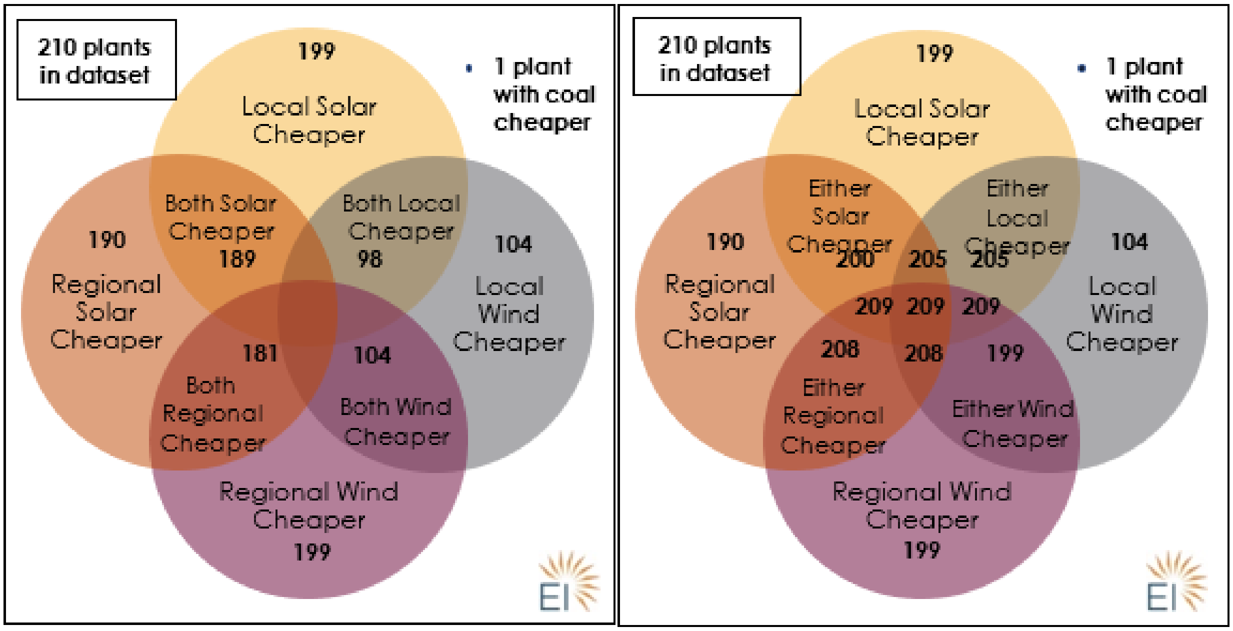
Regulators should require examination of GETs within integrated resource planning to ensure these solutions are not overlooked. Grid operators should examine the potential for these new technologies to add capacity to the existing system within the compliance timeline provided by the EPA's rules. The FERC Order 2023 did require that grid operators consider GETs when determining upgrades required by interconnection studies, but grid operators should also consider them as a part of proactive planning processes.

**Proactively plan transmission needs to enable coal retirement.** When coal plant owners decide to retire a plant, the grid operator often evaluates how the retirement will impact grid reliability, both in real time and from a resource adequacy perspective. In several cases, grid operators have found a reliability imperative to keep the plant online until new transmission can be built to ensure local grid stability. This has led to uneconomic coal plants staying online under "reliability must run" contracts that allow these plants to charge customers higher prices while waiting for replacement resources.[55] To address this issue, RTOs should not wait for retirement announcements to study the impact of retiring coal on the grid—instead, they should proactively inform generation owners and their state regulators which services will be needed to inform any potential generator replacement that could avoid lengthy and costly transmission solutions.

Once the EPA rules are finalized, RTOs can work proactively by developing scenarios in which all coal plants retire to assess needs for replacement resources and associated transmission infrastructure, as would be required by FERC's proposed rule on planning for regional and interregional transmission capacity.[56] In addition, RTOs should coordinate with states and utilities as they develop plans to comply with proposed GHG standards, both through the development of state implementation plans that would be required by the EPA's proposed rules and through utility integrated resource planning and procurement, as described below. This proactive planning will help bring new resources online before retirements are announced, saving customers and utilities money, and ensuring a reliable grid as fossil retirements continue.

**Enable re-use of existing interconnections at retiring fossil plants.** In addition to proactively planning new transmission, reusing a retiring coal plant's existing interconnection can accelerate the pace of bringing replacement resources online. Every coal plant in the U.S. has economic solar or wind resources within 30 miles.[57]

**Figure 10. Economic comparison of local wind and solar to coal costs**




Source: Energy Innovation, Coal Cost Crossover 3.0, 2023.[58]

To help enable re-use of an existing interconnection, asset owners should consider opportunities to transfer or re-use the interconnection themselves for new generation. Grid operators can also streamline this process. For example, MISO maintains a separate interconnection queue for resources coming online that plan to re-use an existing interconnection. However, PJM has no such process, meaning new resources that plan to use an existing interconnection must go through the standard interconnection queue; this may lead to sub-optimal outcomes such as reliability must run contracts to extend the life of uneconomic power plants or costly transmission-oriented solutions. Without a change in policy, resources that are directly related to replacing reliability services of retiring coal plants may not be able to come online as envisioned in Sections 1 and 2 above.

But this is not simply an RTO problem. State regulators and the power-plant-owning utilities they regulate must coordinate and approve generator replacements through their planning processes. State policymakers, utility regulators, and utilities themselves can support reliability through the transition through the following actions:

**Develop state compliance plans that set specific timelines for retirements and retrofits.** The EPA's proposed rules require states to develop and submit state plans that detail how affected coal- and gas-fired power plants will comply with the rules within 24 months of the final rules being published.[59] Among other things, these state plans will assign affected plants to subcategories, defining retirement timelines, emissions standards, or operational limits.

These state compliance plans will be important sources of transparent information about the timelines for retirements, retrofits, and operational limits for existing coal- and gas-fired power plants. Specific, enforceable retirement dates will allow RTOs and other entities to develop plans and processes that will enable new resources to come online in a timely manner to replace retiring resources, affording ample time to make upgrades to address local reliability concerns.

However, if states fail to issue plans that demonstrate compliance with the rules or fail to identify timelines for plant retirements and retrofits, the resulting uncertainty could hamper other entities' ability to effectively plan for a reliable transition.

**Undertake proactive resource planning and procurement that incorporates compliance with the proposed EPA rules.** Many utilities, comprising more than 40 percent of electricity demand and serving nearly 100 million electricity customers, undertake some form of long-term integrated resource planning to evaluate future electricity system needs, resource options, and objectives.[13] State public utility commissions or public utility boards oversee nearly all these plans.

For states and utilities that conduct integrated resource planning, utilities and their regulators should reflect the EPA's proposed rules requirements, outline compliance pathways and timelines for affected power plants, and select a portfolio of replacement resources to replace retiring resources and meet future electricity system requirements while ensuring adequate resources to operate the system. These plans can provide long-term visibility into retirement timelines and the need to bring new resources online.

Utility resource planning can incorporate the value of demand-side investments, such as energy efficiency, demand response, and distributed energy resources like solar and storage, all of which can contribute to meeting electricity system reliability needs in addition to supply-side resources. For example, Portland General Electric's 2023 Clean Energy Plan and Integrated Resource Plan incorporates energy efficiency, demand response, and aggregations of distributed resources as "virtual power plants" as part of a portfolio to meet growing electricity needs and replace retiring fossil assets.[60]

Finally, utility plans must translate into procurement. Utilities can undertake competitive all-source procurement to identify the lowest-cost resources to meet utility needs.[61] As lead times for project development and interconnection lengthen, utilities can ensure that resources needed to replace retiring resources are under development in time and coordinate with RTOs to ensure sufficient interconnection and transmission planning processes to bring those resources online in a timely manner.

Because resource adequacy and procurement often fall to regulated utilities, integrated resource planning is the venue where utilities can begin to design procurement to reuse interconnection rights. RTOs must work to make more transparent the reliability services the grid needed from a retiring plant and feed that back to the regulated procurement process, which can ultimately result in an economic and expedited replacement of that generation. The long lead-time in the EPA rules leaves states and RTOs ample time to design processes for an orderly transition that allows for faster interconnection.

## CONCLUSION

The pace of transition projected under the EPA's proposed rules has roused concerns from industry players, particularly grid operators and utilities. These concerns are not unwarranted—while the clean energy transition is well underway and is technically feasible on reliability grounds, proceeding under a business-

[13] Based on data from EQ Research, September 2023.

as-usual approach will make it difficult to attain a clean, affordable, and reliable electricity system as fossil plants retire. This is not because a grid powered by clean energy is fundamentally unreliable, but instead because the pace of adding these new clean energy resources has not been fast enough to keep up with the pace of retirements.

The transition has largely been happening ad hoc, with renewables and natural gas beating out coal plants based on cost, leading to sudden retirements that are not always paired with the necessary new additions. These new additions are failing to arrive not due to lack of interest or economic barriers, but largely because authorities over procurement, infrastructure, and reliability have so far been misaligned around how to manage the energy transition. This has resulted in a backlog of interconnection requests and failure to plan for needed transmission upgrades. The industry's lack of confidence in our ability to meet these reforms reflects more our flawed policies and practices than a technical constraint.

New policies are needed, particularly to enable a faster pace of connecting new clean energy to the grid. Most of these policies, from reforming interconnection processes and using new technologies to increase transmission capacity in the short term, to proactively planning the grid around the retirement of fossil plants that will continue under the proposed rules, are within the purview of grid operators and utilities. In fact, new regulations would provide more certainty around the pace of retirements, allowing grid operators and utilities to prepare more effectively. With the EPA's proposed rules, there is an opportunity for the utilities and grid operators to step up and lead.

## APPENDIX: EXISTING UTILITY PLANS TO PHASE OUT COAL BY 2035

Grid operators and utilities have already demonstrated that coal-fired electricity generation is not necessary to reliably operate an electricity grid. According to EIA Form 930 data, many balancing area regions of the U.S. grid generated less than 0.5 percent of total electricity generation using coal in 2022. Balancing areas are responsible for balancing electricity demand, generation, and interchanges with neighboring regions while meeting operating requirements set by NERC. Coal-free balancing areas are managed by large ISOs such as the California ISO, New York ISO, and ISO New England; large vertically integrated utilities such as Florida Power and Light; and federal power agencies like Bonneville Power Agency.[62] Together, these regions accounted for 15 percent of net electricity generation in the U.S. in 2022.

Not only are large portions of the U.S. electricity grid already running coal, but many more are planning to end coal use by 2035 or sooner. As detailed below, 25 large coal-owning utilities, which together serve 19 percent of U.S. electricity demand, have plans to be coal free by 2035 or sooner. These plans cover more than 40 GW of coal—21 percent of currently operating coal capacity—which as of April 2023 stood at 192 GW.[63] The plans demonstrate that while some entities affected by this rule may protest section 111(d) restrictions on coal plant emissions on reliability grounds, the industry's emerging consensus is that unabated coal is not necessary for reliable operation and resource adequacy.

Many of these plans were developed before the IRA's passage, which significantly enhanced federal incentives for clean energy production and CCS. Even without the proposed rules, we expect to see many more utilities develop plans to phase out unabated coal use by 2035 or sooner as those utilities update their resource plans to account for the suite of federal clean energy tax credits now available.

### Twenty-five large utilities plan to end coal use by 2035 or earlier

Based on data on utility integrated resource plans (IRPs) collected by EQ Research and EIA data, we identified 25 large utilities that currently own or are contracted to take power from an estimated 40 GW of coal capacity, and which have plans to be coal free by 2035 or sooner. In many cases, these plans are articulated in an IRP—a detailed utility-led study of electricity system reliability and future resource needs. IRPs consider requirements of environmental policy and electricity system resource costs and characteristics, using modeling to determine the optimal balance of meeting electricity system requirements while minimizing the costs and risks to consumers.

Table 2 shows the list of large utilities that plan to be coal free by 2035 or sooner, the amount of coal capacity to be retired between 2023 and 2035, and each utility's plans for resource additions to meet system needs.

The plans represented in this table account for 740 million megawatt-hours (MWh) per year of electricity demand (representing roughly 19 percent of U.S. electricity demand) and cover 40 GW of coal capacity (accounting for 21 percent of currently operating coal capacity in the U.S.). The plans surveyed here include 56 GW of solar additions, 15 GW of wind additions, 10 GW of storage additions, and 32 GW of gas capacity additions between 2023, along with the coal phase-out date for each utility.

## Table 2. Utilities with coal phase-out plans

| | | | | | Portfolio Changes from 2023 to Coal Phase-Out Date (MW) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Name | Utility Type | Retail Cust. | Electricity Demand (MWh) | Coal Phase-Out Date | Coal Rets. | Other Rets. | New Solar | New Wind | New Energy Storage | New DSM | New Gas | Other New |
| Tennessee Valley Authority | Federal Power Agency | 10,000,000 | 152,906,037 | 2035 | (7,900) | - | 5,145 | - | - | - | 7,700 | - |
| Florida Power and Light | Investor Owned | 5,691,891 | 123,054,514 | 2029 | (717) | (219) | 13,261 | - | 100 | 167 | 271 | - |
| Georgia Power Co | Investor Owned | 2,657,949 | 82,944,041 | 2035 | (3,848) | (1,506) | 8,130 | - | 1,270 | - | 9,166 | 1,158 |
| DTE Electric Company | Investor Owned | 2,244,945 | 41,481,966 | 2035 | (4,336) | (70) | 6,000 | 2,400 | 1,560 | - | 2,216 | - |
| Northern States Power Co (Xcel) | Investor Owned | 1,787,958 | 39,923,938 | 2030 | (2,295) | (1,456) | 2,570 | 1,350 | 200 | 341 | - | 1,441 |
| Consumers Energy Co | Investor Owned | 1,870,123 | 32,251,402 | 2025 | (1,908) | - | 1,300 | - | - | 94 | 2,177 | - |
| Arizona Public Service Co | Investor Owned | 1,317,266 | 29,228,236 | 2031 | (1,357) | - | 3,100 | 1,033 | 3,109 | 187 | 1,859 | - |
| Public Service Co of Colorado | Investor Owned | 1,535,755 | 28,932,674 | 2031 | (2,549) | - | 2,758 | 2,300 | 400 | 78 | 505 | 1,276 |
| City of San Antonio (CPS Energy) | Municipal | 885,307 | 22,605,374 | 2028 | (1,345) | (1,279) | 1,080 | 300 | 750 | - | 2,569 | 102 |
| Entergy Arkansas LLC | Investor Owned | 727,743 | 22,281,971 | 2030 | (1,194) | (522) | 2,730 | 1,500 | - | - | - | - |
| LADWP | Municipal | 1,465,281 | 20,800,118 | 2025 | (1,200) | (9) | 98 | 141 | 152 | 150 | 553 | 92 |
| Public Service Co of Oklahoma | Investor Owned | 568,226 | 18,205,777 | 2026 | (465) | (79) | 1,350 | 2,800 | - | - | - | - |
| Indiana Michigan Power Co | Investor Owned | 604,489 | 17,207,677 | 2028 | (2,123) | - | 1,300 | 800 | 315 | 4 | 750 | - |
| Northern Indiana Public Service Co | Investor Owned | 483,297 | 15,607,008 | 2028 | (1,191) | (155) | 1,665 | 204 | 270 | - | 353 | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Indianapolis Power & Light Co | Investor Owned | 514,140 | 12,972,559 | 2025 | (1,487) | (36) | 478 | - | 298 | 111 | 1,052 | - |
| Entergy Mississippi LLC | Investor Owned | 458,987 | 12,744,935 | 2030 | (413) | (1,266 ) | 450 | 250 | - | - | - | - |
| Wisconsin Power & Light Co | Investor Owned | 487,076 | 11,185,445 | 2026 | (1,003) | - | 764 | - | - | - | - | - |
| Great River Energy | G&T Co-op | 725,000 | 10,650,069 | 2031 | (1,050) | - | 200 | 1,171 | 202 | - | - | - |
| Mississippi Power Co | Investor Owned | 190,660 | 9,254,379 | 2027 | (502) | (474) | - | - | - | - | - | - |
| Public Service Co of NM | Investor Owned | 540,035 | 9,163,032 | 2031 | (200) | (409) | 240 | - | 438 | 109 | 480 | - |
| Hoosier Energy Rural Electricity Cooperative, Inc | G&T Co-op | 710,000 | 7,321,571 | 2023 | (990) | - | 500 | 300 | - | - | 300 | - |
| Orlando Utilities Commission | Municipal | 261,047 | 6,823,920 | 2027 | (663) | - | 894 | - | 350 | - | 823 | - |
| Colorado Springs Utilities | Municipal | 244,132 | 4,785,436 | 2030 | (415) | - | 175 | 200 | 167 | 90 | 180 | 20 |
| Vectren/ Centerpoint | Investor Owned | 149,852 | 4,644,664 | 2027 | (995) | - | 756 | 200 | - | - | 730 | - |
| Platte River Power Authority | Municipal Power Agency | 169,856 | 3,133,575 | 2030 | (352) | - | 300 | 250 | 300 | - | 104 | - |
| **Total** | | **36,291,015** | **740,110,318** | | **(40,498)** | **(7,479 )** | **56,494** | **15,199** | **9,879** | **1,331** | **31,788** | **4,089** |

Notes and Sources:
Resource additions and retirements based on data from EQ Research, IRP As a Service, as of June 2023. Additional data was collected on the Tennessee Valley Authority, Great River Energy, Orlando Utilities Commission, Colorado Springs Utilities, Vectren/Centerpoint, and Platte River Power Authority from utility websites and IRPs.
Coal phase-out dates are based on the expected retirement year of each utility's last remaining coal plant, based on data from EQ Research, utility IRPs, and EIA Form 860.
Retail customers and retail electricity demand from EIA Form 861 and estimated based on utility websites and EQ Research data for the Tennessee Valley Authority, Hoosier REC, Great River Energy, and Platte River Power Authority based on retail customers and demand of member distribution cooperatives and municipal utilitie

## Case Studies

Each of the utilities listed in Table 2 has developed a plan to end the use of coal-fired electricity generation. Below, we explain the decisions of four utilities to retire all coal and rapidly add renewable resources in more detail.

We chose utilities that represent a broad range of ownership types and operating structures (integrated investor-owned utilities, generation and transmission cooperatives, municipal utilities), as well as utilities that currently or have recently relied heavily on coal-fired generation as a large share of the electricity generation mix. In addition, according to data from the Smart Electric Power Alliance, three of the utilities (Northern Indiana Public Service Company, Xcel Energy, and CPS Energy) have utility-level or parent-company goals to achieve net-zero carbon dioxide emissions by 2050 or sooner. The fourth utility (Great River Energy) is subject to Minnesota state policy that requires cooperative utilities to generate 100 percent of electricity from emissions-free sources by 2040.[64]

The plans described below were completed before the IRA's passage, which significantly increased the amount of federal support for clean energy and substantially shifted the economics of clean energy relative to coal.

### Xcel Energy

Xcel Energy operates vertically integrated investor-owned utilities in Colorado and the Upper Midwest. In Colorado, Xcel's operating company, Public Service Company of Colorado (PSCo), serves 1.5 million customers and supplies 29 million MWh of electricity per year. In August 2022, the Colorado Public Utilities Commission approved a settlement agreement that would retire or fully convert to gas PSCo's remaining coal units by the beginning of 2031.[65] Before the agreement was reached, the utility had been proposing to build over 2.7 GW of distributed and utility-scale solar, 400 MW of storage, 2.3 GW of wind, and 1.3 GW of firm dispatchable capacity by 2031,[66] although these amounts are likely to change to account for accelerated coal retirement.

Northern States Power Company (NSPC), Xcel Energy's Upper Midwest utility, serves 1.8 million customers and supplies 40 million MWh of electricity demand per year. In 2020, the utility expected to meet 16 percent of electricity demand from coal generation, 28 percent from gas, 26 percent from nuclear power, and 30 percent from renewable energy resources.[67] Because NSPC has produced more recent and detailed plans to transition from coal by 2030, we will focus on that plan for the purpose of these comments.

NSPC filed an updated IRP in June 2020 that outlined a transition from coal-fired power with the retirement of the utility's entire coal fleet by 2030. The utility currently operates four coal units, totaling 2.7 GW in generating capacity: the 511 MW Allen King power plant, and 2.2 GW of capacity across three units at the Sherburne County power plant (Sherco). The IRP maintained the utility's currently scheduled retirements of Sherco units 2 and 1 in 2023 and 2026, respectively, and proposed retiring the King power plant in 2028. In addition, the plan proposed retiring Sherco unit 3 by the end of 2029.[68]

NSPC initially proposed to build 3,500 MW of new solar, 835 MW of new combined cycle gas, and 374 MW of peaking gas resources by 2030, along with investing in energy efficiency and demand response.[69] In response to stakeholder concerns about climate impacts of new gas, the utility filed an alternate plan in

June 2021 that removed the combined cycle gas proposal and proposed to meet system needs with 2,570 MW of solar, 1,350 MW of wind, 200 MW of energy storage, 340 MW of energy efficiency and demand response, and 1,400 MW of unspecified firm capacity resources by 2030.[70] By 2030, NSPC's resource mix would consist of no coal, 19 percent natural gas, 26 percent nuclear, 39 percent wind, 13 percent solar, and 3 percent other carbon-free resources, achieving 81 percent carbon-emissions-free generation by 2030.[71]

As part of this resource planning process, NSPC undertook extensive reliability modeling. The utility used modeling software that represents every hour of the year in chronological order to capture the timing and profile of the utility's capacity and energy needs in each projected year. In addition, the utility modeled extreme weather conditions based on the January 2019 Polar Vortex event, during which the Upper Midwest region saw elevated electricity demand coinciding with multiple days of low wind output. Finally, the utility evaluated its ability to provide black start services in the unlikely case it would need to re-energize the grid after a widespread outage. Across these reliability needs, NSPC concluded that its plan to retire coal and significantly increase wind and solar would adequately meet the utility's needs.[72]

### Northern Indiana Public Service Company

Northern Indiana Public Service Company (NIPSCO) is a vertically integrated investor-owned utility that serves roughly 480,000 customers and supplies more than 15 million MWh of electricity per year. Today, NIPSCO relies heavily on coal. The company expected to meet annual energy needs in 2021 with 58 percent coal generation, 25 percent natural gas, and 15 percent wind.[73]

In 2018, NIPSCO undertook a comprehensive IRP process, beginning with an all-source request for proposals that provided cost and performance data, which NIPSCO then used in its system-wide modeling.[74] That IRP resulted in NIPSCO selecting a portfolio that retired the remainder of its coal fleet by 2028, with the bulk of replacement resources from new wind and solar, driven by competitive costs discovered through NIPSCO's all-source resource solicitation process. NIPSCO refined this analysis in 2021 with updated cost and performance assumptions as well as a more detailed reliability assessment, selecting a portfolio that replaced the utility's Michigan City and RM Schahfer coal units (totaling 2.2 GW) with 2.7 GW of solar, 1 GW of wind, 353 MW of peaking gas and uprates of existing gas units, and 300 MW of energy storage through 2030, as well as additional investment in energy efficiency and demand response.[75] NIPSCO's plan includes short-term reliance on wholesale capacity purchases from the MISO market through 2024, as new renewables and storage resources come online.[76]

NIPSCO's 2021 IRP undertook a detailed reliability assessment that evaluated portfolios' ability to provide a range of reliability and system services, including black start, energy adequacy, ability to provide ramping, frequency response and operational flexibility services, and more. NIPSCO's IRP found that the preferred portfolio performed well on all the reliability and system services measures evaluated.[77]

NIPSCO's coal replacement planning illustrates the value of detailed system planning informed by market-based resource cost and performance data, and it supports the EPA's baseline scenario, which sees nearly all coal retiring by 2035 based on economics alone. The new federal incentives for clean energy under the IRA significantly expand opportunities for cost-effective coal retirement and clean energy replacement.

## Great River Energy

Great River Energy (GRE) is a generation and transmission (G&T) cooperative that provides wholesale electricity to member cooperatives across Minnesota. GRE does not sell power directly to retail customers; rather, it sells power to member distribution cooperatives under long-term contracts. GRE's members serve more than 700,000 customers, and GRE sold more than 10 million MWh in 2022.

G&T cooperatives like GRE are unique in their exposure to coal-fired electricity generation and the financial impacts of a transition from coal. G&T cooperatives own roughly 12 percent of operating coal capacity, but generate only 4 percent U.S. net electricity generation from resources they own.[xiv] In addition, many G&Ts face significant financial barriers to early retirement and replacement of coal-fired power plants because of high existing debt loads and limited ability to raise sources of capital for new investment.[78] The U.S. Department of Agriculture's New ERA Program, authorized in the IRA, provides significant new resources to support rural electric cooperatives' transition from coal to clean energy.[79] This will enable many rural electric cooperatives to undertake the type of transition from coal that GRE is planning.

GRE has long relied on coal as a large part of its generation portfolio. In 2021, GRE generated 57 percent of its energy mix from coal, 25 percent from wind, 3 percent from natural gas, and 15 percent from market purchases without a specified source.[80] The majority of this coal generation came from GRE's 1.2 GW Coal Creek Station in North Dakota, which delivers energy to GRE in Minnesota over a dedicated high-voltage direct current transmission line.

After initially announcing plans to retire the plant in 2020, citing the plant's high operating cost relative to market prices,[81] GRE changed course and sold the plant. In 2022, GRE finalized the sale of Coal Creek Station to Rainbow Energy, while entering a contract to purchase power from the plant; the purchases step down over time, completely phasing out by 2031.[82] In addition, GRE operates the 99 MW Spiritwood Station, a coal-fired combined heat and power plant. The plant has been retrofitted to be able to burn natural gas exclusively, and GRE has announced plans to convert the plant to gas.[83]

Between 2023 and 2031, when GRE's contract with Rainbow Energy phases out, GRE plans to build 200 MW of solar, 1,171 MW of new wind, and 201.5 MW of energy storage capacity (including a small demonstration of long-duration iron-air battery technology). These capacity additions are complemented with expected demand-side energy efficiency and demand response, plus an increase in the amount of energy that member cooperatives can self-supply with local renewable energy resources from 5 to 10 percent.[84] While GRE's IRP does not specify the extent to which system needs are met with future MISO market purchases, GRE's central assumption limits market purchases to 25 percent of annual demand.

GRE's reliability needs were modeled on a seasonal basis, based on seasonal planning reserve margins that varied from 7.4 percent in summer to 25.5 percent in winter, applied to seasonal peak demand. The contribution of various resources to meeting these reliability requirements was based on MISO's Effective Load Carrying Capability estimates. By operating as part of MISO, one of the country's largest integrated wholesale electricity market operators, GRE can tap into a wide array of regional resource adequacy resources while benefitting from regional diversity in electricity demand and generator production profiles.

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[xiv] Calculated based on data from EIA Form 861, 2021. Excludes power purchased by G&T cooperatives to serve member demand.

### CPS Energy (City of San Antonio, TX)

CPS Energy is a municipal utility in San Antonio, Texas, serving 885,000 customers and supplying more than 22 million MWh of demand annually, making it the largest municipal utility in the U.S. by total electricity demand.[85]

In 2023, CPS expects to meet approximately 30 percent of electricity demand from coal, 30 percent from gas, 25 percent from nuclear power, and 15 percent from renewable energy resources.[86] Since the 2018 closure of the 871 MW Deely Power Plant, CPS's coal generation has come entirely from the 1.3 GW JK Spruce Power Plant.

In February 2023, CPS's board approved a resource plan that would end the utility's reliance on coal by retiring JK Spruce Unit 1 in 2028 and converting JK Spruce Unit 2 to run solely on natural gas after 2027. In addition, CPS plans to retire 1.7 GW of aging gas-fired capacity by 2030. CPS's plan would meet growing demand and replace the utility's last remaining coal units and retiring gas with a mix of renewable energy, energy storage, and new natural gas generation. By 2030, the utility would add roughly 3 GW of gas capacity (including the 785 MW conversion of Spruce 2), 500 MW of wind capacity, 1,180 MW of solar, and 1,060 MW of energy storage.[87] The resulting portfolio would meet CPS's 2030 energy needs with roughly 21 percent nuclear, 23 percent wind and solar, and 56 percent natural gas generation.[88]

In developing its resource plan, CPS undertook detailed reliability and risk assessment analysis. Across the portfolios CPS developed and considered in this plan, it accounted for a 13.75 percent capacity reserve margin above CPS's peak demand, while developing capacity accreditation for each resource that accounts for that resource's contribution to peak net demand (total demand net of renewable energy).[89]

In addition, CPS undertook a scenario analysis simulating extreme winter weather and corresponding market conditions based on the impacts of Winter Storm Uri in February 2021, as well as extreme summer weather conditions based on the July-August 2021 Texas heat wave. This scenario analysis allowed CPS to assess the performance of portfolios on cost, reliability metrics, and exposure to market volatility under extreme conditions.[90]

CPS's board ultimately determined that a portfolio that retires JK Spruce and meets future needs with a mix of renewable energy, energy storage, and gas generation resources strikes the right balance as to cost, environmental performance, reliability, and risk.

## Key takeaways

Many utilities are planning a transition from coal-fired electricity by 2035 or sooner. This transition is driven in large part by the potential for cost savings as aging and higher-cost coal power plants become less competitive to continue operating as the cost of clean energy alternatives declines.[91]

Utilities planning a transition from coal include a broad range of utilities, from some of the nation's largest investor-owned utilities to small utilities, municipal utilities, and rural electric cooperatives. These transitioning utilities plan to meet their system needs with a mix of new wind and solar resources, natural gas-fired generation, energy storage, and other technologies. Many of these plans were developed before the IRA's August 2022 passage, which significantly increased and extended federal incentives for clean electricity. As more utilities update their plans to account for the IRA, we can expect more to set timelines and plans for coal phaseout.

These utilities have demonstrated rigorous planning, drawing on rapidly evolving technology options and resource costs and employing modern electricity system modeling tools to select resource portfolios that minimize costs and risks while meeting reliability and environmental performance goals. These plans often result from an iterative process with regulators and third-party stakeholders, providing transparency and scrutiny to the planning process.

The growing list of utilities aligning with this coal retirement timeline based on market economics alone supports the EPA's projection that even without the proposed rules, nearly all coal will retire by 2035. Even before the IRA, utilities around the country were committing to end their use of coal-fired electricity by 2035, demonstrating the reliability, feasibility, and cost-effectiveness of a transition from coal to cleaner sources of electricity that will be supercharged by new federal incentives and continued technological progress. Transitioning from coal is also in utility shareholders' and consumers' best interests—Morgan Stanley utility stock analysts indicated that utilities leading on the transition from fossil fuels, especially coal, have higher stock valuations than their peers.[92]

No doubt, the EPA was aware of these utility plans in considering its proposed rule impacts, and utilities that raise objections to the rules should take stock of their peers that are already planning to exceed the rules' requirements. These utilities help demonstrate that many industry actors already understand what the studies examined in Sections 1 and 2 of this report show: electricity systems large and small can be resource adequate, affordable, and operationally reliable without coal-fired power by 2035 or sooner, even as the share of renewable energy grows.

## ENDNOTES

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[11] Robin Just, "EPA's Proposed Greenhouse Gas Emission Standards for Power Plants."

[12] Robin Just, "EPA's Proposed Greenhouse Gas Emission Standards for Power Plants."

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