U.S. House Committee on Energy and Commerce
Subcommittee on Environment, Manufacturing, and Critical Materials
"Clean Power Plan 2.0: EPA's Effort to Jeopardize Reliable and Affordable Energy for States"
[November 14, 2023]

1. Executive summary of a report from EFI Foundation entitled "How Much, How Fast? Infrastructure Requirements of EPA's Proposed Power Plant Rules," October 2023, submitted by the Majority.
2. Joint comments of Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), PJM Interconnection, and Southwest Power Pool to the Environmental Protection Agency, submitted by the Majority.
3. Letter to Administrator Regan from North Dakota Attorney General Drew H. Wrigley, August 8, 2023, submitted by the Majority.
4. Letter to Administrator Regan from Ohio Attorney General Dave Yost, August 8, 2023, submitted by the Majority.
5. Letter to Administrator Regan from Tennessee Division of Air Pollution Control Director Michelle Walker Owenby, August 7, 2023, submitted by the Majority.
6. Letter to Administrator Regan from Utah Division of Public Utilities Director Chris Parker, August 8, 2023, submitted by the Majority.
7. Letter to Administrator Regan from West Virginia Attorney General Patrick Morrisey and several state attorney generals, August 8, 2023, submitted by the Majority.
8. Letter to Administrator Regan from Golden Spread Electric Cooperative, August 8, 2023, submitted by Rep. Pfluger.
9. Letter to Administrator Regan from the Iowa Utilities Board, July 25, 2023, submitted by Rep. Miller-Meeks.
10. North American Electric Reliability Corporation report entitled "2023-2024 Winter Reliability Assessment," November 2023, submitted by Rep. Johnson.
11. Letter to President Biden and Administrator Regan from Climate Action Campaign, August 8, 2023, submitted by the Minority.
12. Letter to Administrator Regan from Rep. Castor and Members of Congress, July 31, 2023, submitted by Rep. Castor.
13. Comments from Attorney Generals to the Environmental Protection Agency, August 8, 2023, submitted by the Minority.
14. Issue brief by Natural Resources Defense Council, April 2023, submitted by the Minority.
15. Report from Analysis Group entitled "Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023," November 7, 2023, submitted by the Minority.
16. Statement of Susan F. Tierney, Ph.D., to the Federal Energy Regulatory Commission Technical Conference, November 9, 2023, submitted by the Minority.
17. Statement of Will Toor to the Federal Energy Regulatory Commission Technical Conference, November 9, 2023, submitted by the Minority.

18. Report from Energy Innovation entitled “Maintaining a Reliable Grid Under EPA’s Proposed 111 Rules Restricting Power Plant Emissions,” November 2023, submitted by the Minority.
19. Comments from American Experiment to the Environmental Protection Agency, August 8, 2023, submitted by the Majority.

U.S. Hydrogen Infrastructure Action Plan

How Much, How Fast?

Infrastructure Requirements of EPA's Proposed Power Plant Rules

EFI FOUNDATION

October 2023

Project Team

Ernest Moniz
President and CEO

Alex Kizer
Project Executive

Tatiana Bruce da Silva
Project Manager & Contributing Sr. Analyst

Additional Contributors

Nick Britton
Research Associate

Emre Gençer
Sesame Sustainability

Paul Sizaire
Sesame Sustainability

Communications Team

David Ellis
Senior Vice President of Policy Strategy & Outreach

Alicia Moulton
Deputy Director of Communications

Georgia Lyon
Communications Associate

Nola Shelton
Senior Graphic Designer

Copy Editing

Danielle Narcisse
M. Harris & Co.

Jane Hirt
M. Harris & Co.

Report Sponsors

The EFI Foundation maintains editorial independence from its public and private sponsors.

The EFI Foundation would like to thank the following organizations for sponsoring the "U.S. Hydrogen Infrastructure Action Plan" project. This report, "How Much, How Fast: Infrastructure Requirements of EPA's Proposed Power Plant Rules" is the first in this series:

Duke Energy Corp.

Exxon Mobil Corp.

Green Horizon Opportunity Fund

Hewlett Foundation

Gas Turbine Association

Mitsubishi Power Americas, Inc.

The EFI Foundation advances technically grounded solutions to climate change through evidence-based analysis, thought leadership, and coalition-building. Under the leadership of Ernest J. Moniz, the 13th U.S. Secretary of Energy, the EFI Foundation conducts rigorous research to accelerate the transition to a low-carbon economy through innovation in technology, policy, and business models. EFI Foundation maintains editorial independence from its public and private sponsors.

Cover photo: Freepik

Table of Contents

List of Figures

Executive Summary

The U.S. Environmental Protection Agency (EPA) is proposing to use its Clean Air Act authorities to set carbon dioxide limits for new gas-fired generators, existing coal units, and certain existing gas-fired generation facilities. This report, part of a series called U.S. Hydrogen Infrastructure Action Plan, evaluates the systemwide impacts of EPA's proposal, especially in terms of the scale, timing, and feasibility of potential infrastructure requirements.

EPA's proposal reflects the need for aggressive power sector decarbonization

In the United States and many other heavily industrialized countries, the electric grid is the linchpin for economywide decarbonization. Shifting to a zero-carbon electricity system could directly reduce one-quarter of U.S. carbon dioxide (CO_2) emissions today and enable additional reductions through increased end-use electrification in buildings, transportation, and other sectors. This led the Biden administration to set a target of 100% carbon pollution-free electricity by 2035 and is driving utilities that now cover nearly 80% of U.S. customers to set midcentury 100% carbon reduction targets.[1]

In May 2023, EPA proposed new emissions limits for fossil fuel-fired generators to align the sector's decarbonization trajectory more closely with the administration's goals. As part of its Clean Air Act (CAA) authorities, EPA is proposing that all existing coal plants and large natural gas generators adopt new technology-based requirements starting in 2030 and 2032, respectively. All new fossil generation, except for gas "peaking" units that operate relatively infrequently, that is, at less than 20% capacity factor, is also subject to these rules.

EPA's proposal includes highly efficient generation, co-firing clean hydrogen (H_2) with natural gas, and carbon capture and storage (CCS) as the low-carbon technologies for compliance, also called "best system of emission reduction" (BSER).

Generally, the proposal requires larger units—300 megawatts (MW) or larger—that run more frequently—50% capacity factor (CF)[a] or higher—to adopt more stringent standards than other plants. EPA determines what classifies as BSER, reflecting technical and economic realities and any non-air-quality health and environmental impacts and energy requirements.[2] According to EPA's Regulatory Impact Analysis (RIA), this proposal would

[a] The capacity factor measures how often a power plant operates for a given period of time. It is calculated by dividing the actual electricity output by the maximum possible output the plant could produce.

reduce U.S. power sector emissions by more than 40 million metric tons (Mt) per year from 2028 to 2042.[3,b] The power sector emitted roughly 1,500 Mt in 2022.

The Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) offer a range of financial incentives across the CCS and clean hydrogen value chains. The IRA—the largest investment in clean energy in U.S. history—also directs EPA to consider the IRA's benefits (e.g., technology-specific tax credits) when determining BSER and other aspects of its authority under Section 111 of the CAA. These policies are appropriately driving high expectations for CCS and clean hydrogen.

The U.S. Department of Energy's *U.S. National Clean Hydrogen Strategy and Roadmap* sees strategic annual demand for clean hydrogen reaching 50 Mt by 2050.[4] DOE's *Pathways to Liftoff: Carbon Management* report suggests that meeting the United States' midcentury emissions reduction targets will require capturing and storing 400 Mt to 1,800 Mt of CO_2 annually.[5]

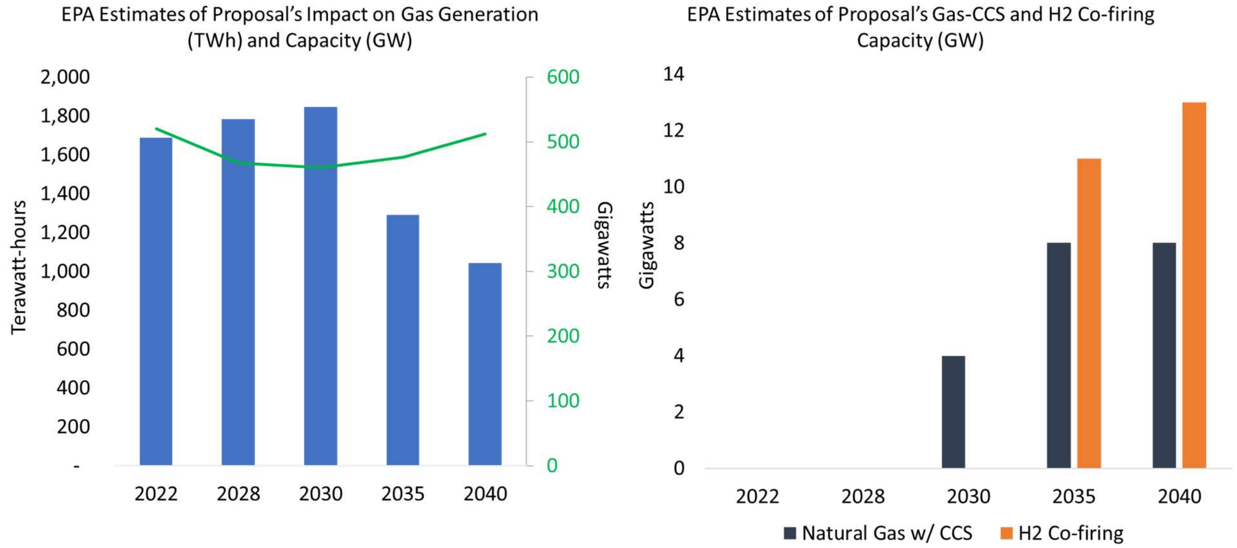
EPA's proposal addresses the scale of the challenge of reaching a carbon-free electric grid before midcentury, but it does not go as far as the Biden administration's goal of 100% carbon-free electricity by 2035. In addition to reflecting the difficult realities of reaching net-zero emissions, the proposal underscores the need for CO_2 removal and negative emissions technologies.

EPA's RIA projects a major shift away from coal in the power sector, including retirement of nearly 200 gigawatts (GW) by 2035, and a long-term strategic role for natural gas as a firming resource. U.S. power sector emissions are down roughly 40% since 2005, led by a shift from coal to natural gas and renewable energy sources.[6] EPA's proposal would accelerate these trends by targeting certain types of unabated fossil fuel-fired generation. EPA projects that its policy will increase gas-fired generation through 2030 (before falling by 2040) and expand gas generation capacity by 2040 (Figure ES 1).[7] EPA also sees modest increases in gas-fired generation with CCS (8 GW by 2040) and co-firing hydrogen with natural gas (13 GW total by 2040).

[b] In July 2023, EPA issued updated modeling results with 9,419 Mt of cumulative emission reduction through 2042 (https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0237). Because the update did not include the full suite of modeling assumptions, the RIA analysis was used for reference in this report.

Figure ES 1.

EPA's estimates of select impacts of proposed power plant rules



Under the proposed power plant rules, EPA estimates natural gas generation will reach a peak in 2030, decreasing from then until 2040. Natural gas capacity is expected to initially fall and then expand in this time frame (left). The capacity of natural gas power plants with CCS and with hydrogen co-firing is expected to increase starting in 2030 (right). Source: See first figure mention in text for sources.

EPA's proposal creates challenging time frames for scaling new clean energy resources

EPA's proposal includes various time and resource requirements for generators depending on their size and how frequently they run during the year. For example, a large coal unit can adopt CCS by 2030 and co-fire with 40% natural gas if it plans to cease operations by 2040, or it can choose to shut down by 2035. A large existing gas generator can co-fire with hydrogen at 30% by volume in 2032, increasing to 96% by 2038, or choose to use CCS at 90% capture by 2035. Facilities can choose from these pathways, leading to facility-by-facility decisions that can impact how much new generation and capacity must be seamlessly backfilled on the system, creating uncertainty in the near term.

EFI Foundation analyzed the possible infrastructure requirements of EPA's proposal using the SESAME[c] modeling platform. Given that EPA's proposal will require certain generators to co-fire with hydrogen, adopt CCS, or reduce operations below 50% CF, modeling scenarios were developed representing these potential outcomes: 1) high hydrogen demand ("High H2"), 2) high CO_2 capture deployment ("High CCS"), and 3) high reduced operations ("High RO").

[c] SESAME stands for Sustainable Energy System Analysis Modeling Environment. https://sesame.mit.edu/

The *Reference Case* in the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2023* was used as a modeling baseline, and the nine EIA electricity regions were used as geographic areas of analysis.[8]

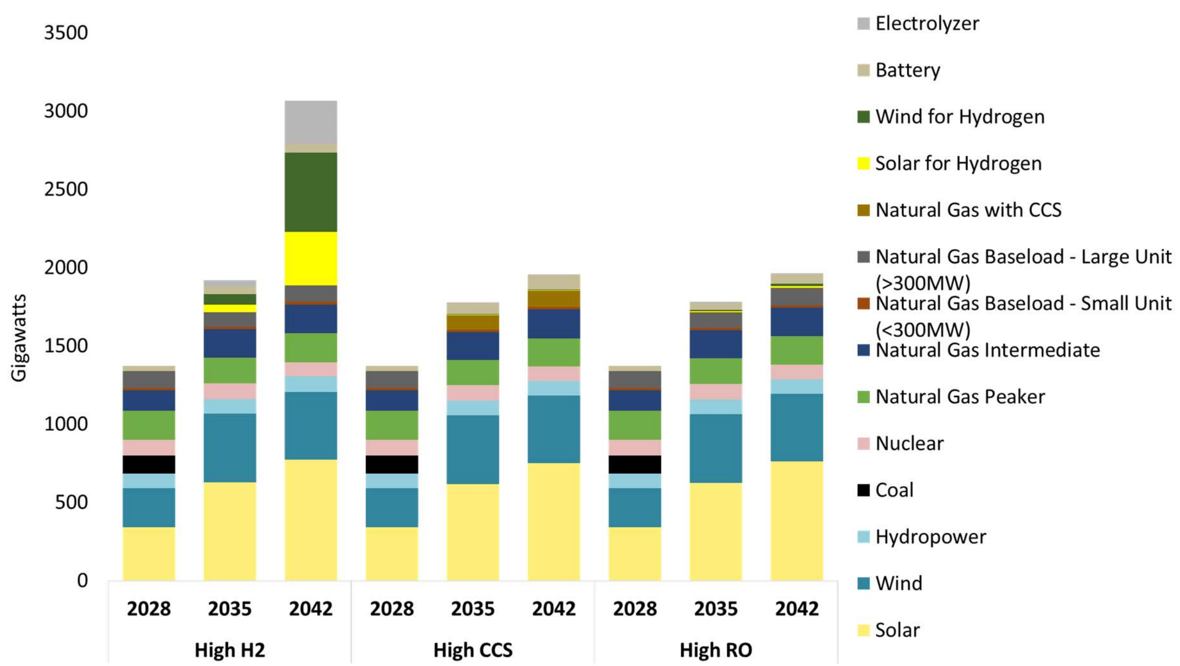
Across all three scenarios, major infrastructure deployments are needed in the next decade that may limit implementation, especially because of the highly decentralized nature of fossil generators and the regional electricity structures (Figure ES 5).

EFI Foundation modeling finds that unabated coal would phase out by 2035, as adopting CCS on existing coal by 2030—per the proposal—faces major financial and permitting headwinds. Roughly a fivefold increase in solar, a threefold increase in wind capacity, and a sixfold increase in battery storage are needed by 2035 compared to today (Figure ES 2).

The modeling also shows important differences between scenarios. For example, in the High H2 scenario, **850 GWs of dedicated renewable energy is needed by 2042 to produce the hydrogen at the life cycle emissions limit proposed by EPA, 0.45 kilograms (kg) CO_2e per kg H_2**. Reaching this scale of renewables deployment for hydrogen takes more than the current rate that renewables are added to the grid: 29 GW of solar and 6 GW of wind were added in 2023.[9] Hydrogen demand is 4 million metric tons per year, or annum (MTPA), in 2035 and 32 MTPA by 2042. There is 105 GW of gas-fired capacity that co-fires 30% hydrogen by volume in 2035 and 307 GW that co-fires 96% hydrogen by 2038. The system needs 37 GW of electrolyzers by 2035 and 275 GW by 2042. The installed gas capacity remains roughly flat through 2042.

Figure ES 2.

EFI Foundation modeling of capacity by technology and year, all scenarios



Technology capacity varies by year depending on the scenario under analysis. Coal is phased out by 2035, while solar and wind increase participation in electricity generation, including to produce clean hydrogen in the High H2 scenario. Natural gas with CCS starts to contribute to capacity by mid-2030 in both the High CCS and High RO scenarios, reaching higher values in the High CCS scenario. Source: EFI Foundation modeling analysis using SESAME tool.

In the High CCS scenario, 94 GW of gas-fired generation adopts CCS by 2035 and 105 GW by 2042, resulting in 150 MTPA of CO_2 captured in 2035 and 170 MTPA by 2042. Roughly 8 GW of dedicated renewables for hydrogen production are needed for the intermediate load units covered by the policy.

In the High RO scenario, around 80 terawatt-hours (TWh) of generation is reduced as large plants lower their CF to 49% (below the 50% threshold). All intermediate units increase generation to 49%, partially covering this gap, and 50 GW of capacity of new smaller gas units come on line.

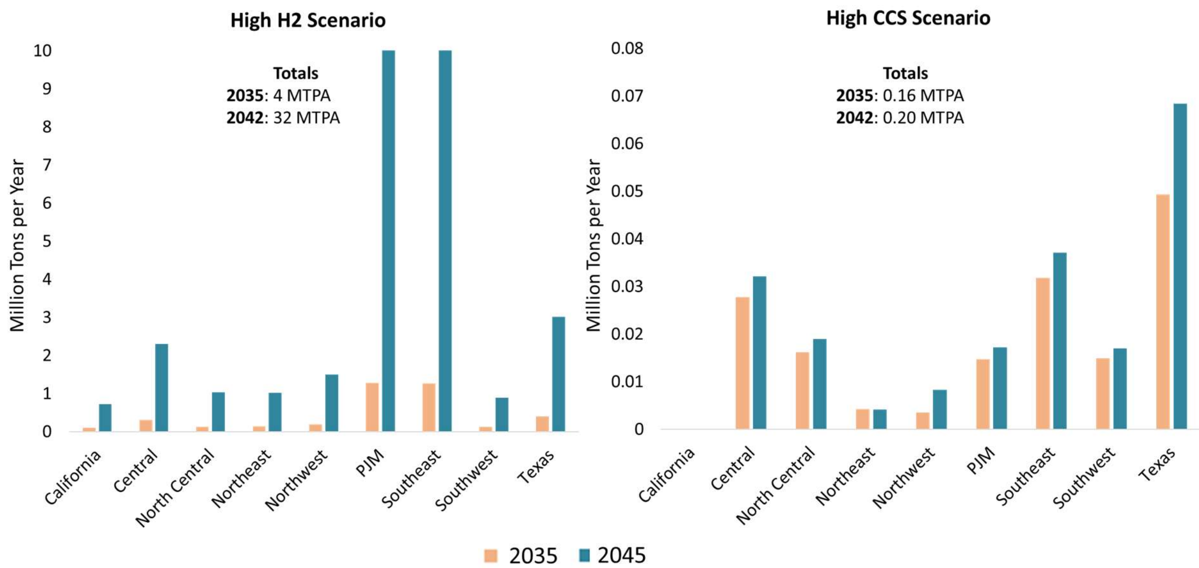
This policy disproportionately impacts regions with existing coal and large gas-fired capacity. Meanwhile, the proposed BSERs are resource dependent and not equally available across the country; some regions have abundant low-cost clean energy resources for hydrogen production and geologic storage potential, while others have neither.

This leads to considerable regional variation in terms of associated costs and compliance options. For example, capital expenditures (CAPEX) can be as high as $18 billion per year for some regions (PJM[d] and the Southeast) or as low as $1.5 billion (Northeast) depending on the modeling scenario. Figure ES 3 shows the possible regional demand for hydrogen and the amount of CO_2 capture needed in EFI Foundation's High H2 and High CCS scenarios, respectively, and highlights wide regional variation. The nine EIA zones (a combination of North American Electric Reliability Corporation and independent system operator regions) were used for this analysis.

[d] See Figure 12 for a definition of regions.

Figure ES 3.

Comparing regional hydrogen demand in 2035 and 2045 in High H2 and High CCS scenarios

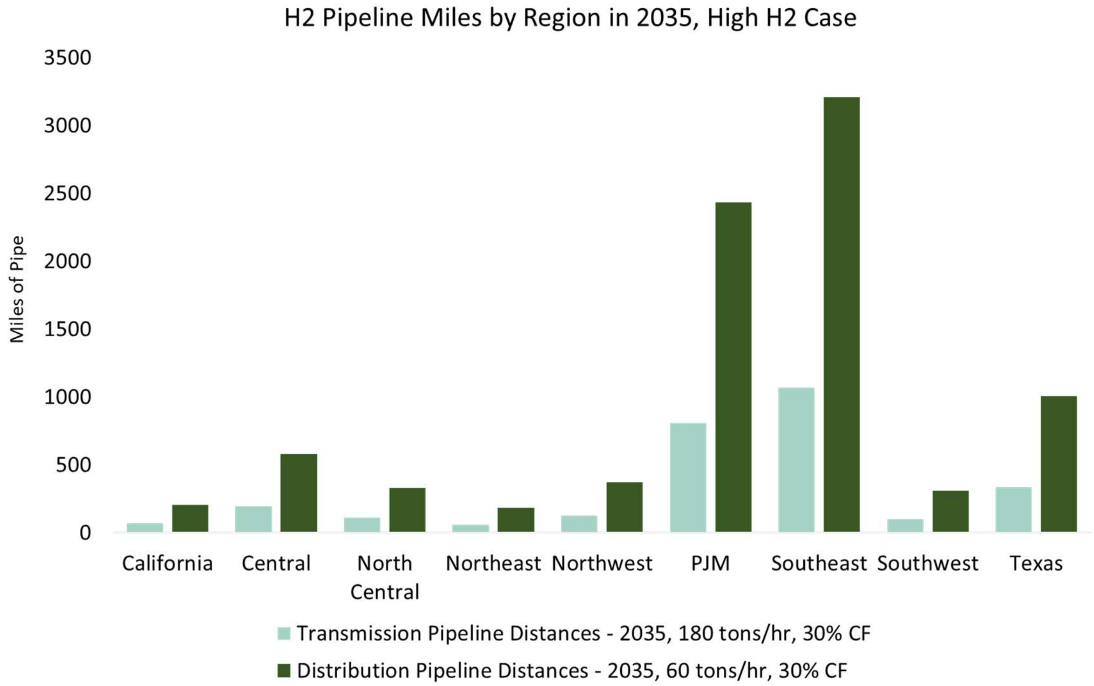


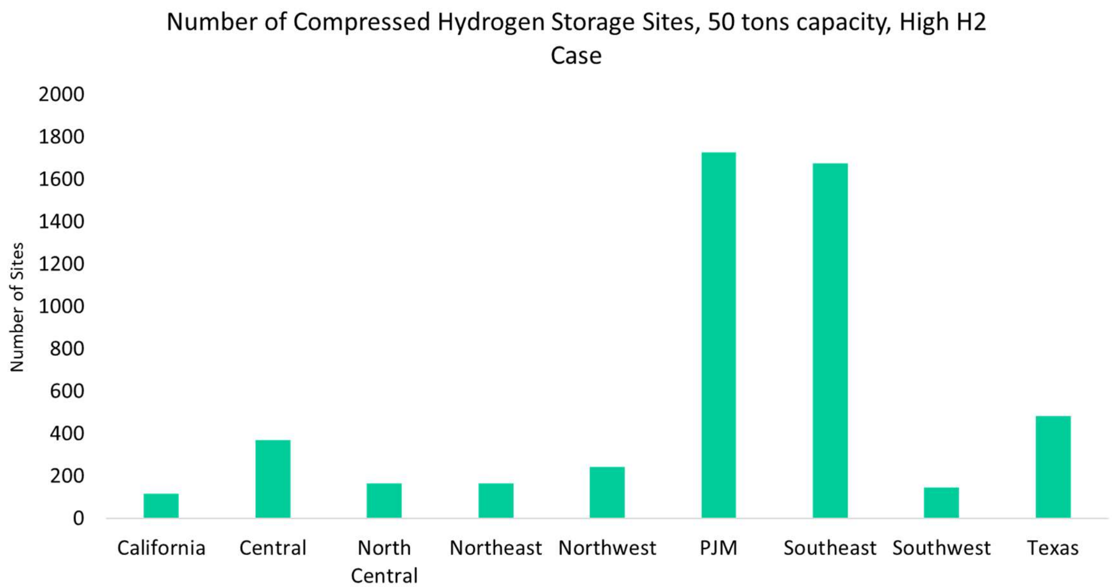
Regional variation is also observed by scenarios. Hydrogen demand is higher in the Southeast, PJM, and Texas, especially by 2042. In the High CCS scenario, hydrogen demand needs still vary by region. Source: EFI Foundation modeling analysis using SESAME tool.

To understand the systemwide impacts of EPA's proposal, EFI Foundation analyzed the infrastructure requirements of each scenario. In the High H2 scenario, for example, **more than 11,000 miles of new hydrogen pipelines (transmission and distribution) and more than 5,000 compressed hydrogen storage sites (50 tons capacity each) will be needed by 2035 (Figure ES 4)**. For context, there are around 1,600 miles of hydrogen pipelines in operation in the United States today. By 2042, nearly 95,000 miles of hydrogen pipeline is needed to accommodate the policy's shift to 96% hydrogen co-firing with natural gas.

Figure ES 4.

Infrastructure requirements in EFI Foundation's High H2 scenario by 2035





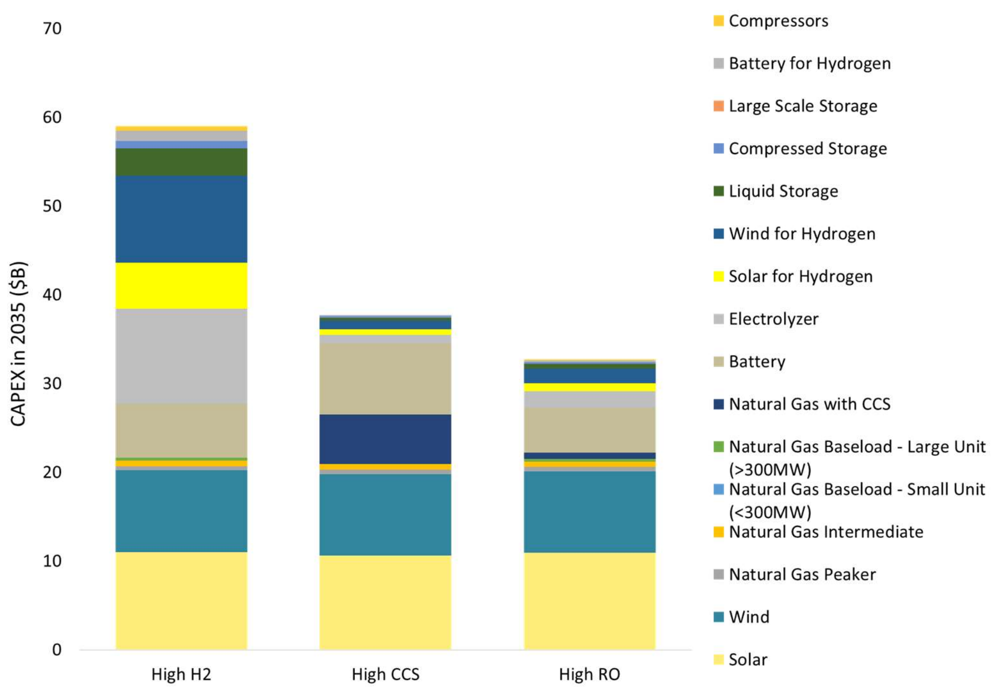
In the High H2 scenario, new infrastructure must be built to accommodate increased hydrogen needs—such as transmission pipelines carrying 180 tons of hydrogen per hour at 30% capacity factor; distribution pipelines carrying 60 tons of hydrogen per hour at 30% capacity factor; and compressed hydrogen storage sites. Infrastructure needs vary widely by region: The Southeast, PJM, and Texas are among the regions with higher infrastructure needs. Source: EFI Foundation modeling analysis using SESAME tool.

Contributing to implementation challenges is the lack of commercial CCS and clean hydrogen projects today. While various aspects of both technologies are commercially available, there are no examples of the full value chains of CCS or clean hydrogen financed, built, and operating in U.S. energy markets. This contributes to first-of-a-kind (FOAK) issues, such as unique engineering challenges and regulatory uncertainty, adding to investment risk for at-scale deployment in the next decade. **EFI Foundation FOAK costs for CCS for gas generators may be up to 40% higher than EPA's estimates, while average U.S. delivered hydrogen costs could be up to 20 times higher.**

According to EFI Foundation modeling, the capital expenditures needed to meet EPA's proposal are intrinsically tied to broader decarbonization deployments. Absent this policy, there will still need to be gigawatt-scale deployments of new wind and solar to reach net-zero emissions. EFI Foundation modeling scenarios show CAPEX requirements between $32 billion and $60 billion per year by 2035, with large regional variation (Figure ES 5).

Figure ES 5.

Capital expenditures in 2035 across EFI Foundation modeling scenarios



Capital expenditures across modeling scenarios depend on the decarbonization pathway. Higher CAPEX is expected in the High H2 case due to increased investment needs in clean hydrogen infrastructure. Costs shown are for 2035 only. Source: EFI Foundation modeling analysis using SESAME tool.

Achieving this level of deployment depends on complementary permitting reform for electricity, hydrogen, and CO_2 systems, enabled by a large workforce and extensive supply chains. While IIJA and IRA incentives offer game-changing support for these technologies, neither policy adequately addresses the permitting reform needed to scale CCS and clean hydrogen infrastructure in the proposal's time frames. The White House and Congress have issued multiple proposals for energy permitting reform since the passage of the IRA to help fill this gap. Due to the cross-jurisdictional nature of electric power, CCS, and hydrogen projects, these reforms will need to greatly improve coordination among firms, sectors, and governments.

Opportunities to advance CCS and clean hydrogen deployment

EPA's current proposal faces major implementation challenges, considering the amount of infrastructure that could be needed in the next decade to support potentially hundreds of new and existing generators throughout the country. While this proposal addresses the scale of the challenge of reaching a carbon-free electric grid before midcentury, it does not go as far as the Biden administration's goal of 100% carbon-free electricity by 2035. The agency should consider ways to add flexibility and more regionality to its approaches to ensure large-scale decarbonization efforts are deployed moving forward.

The following are three examples of how EPA and other relevant federal and state agencies can support CCS and clean hydrogen in electric sector decarbonization:

- **Align new federal policies advancing CCS and clean hydrogen deployment to the IRA***.* The IRA directed tens of billions of dollars into new and expanded incentives for CCS and clean hydrogen production and extended the construction window for eligibility of the 45Q tax credit for carbon sequestration to January 1, 2033. EPA's proposal requires coal-fired units that plan to operate beyond 2039 to place carbon capture into service by 2030, two years ahead of the 45Q credit deadline to begin construction. Aligning EPA with the existing 45Q policy requirements could improve investor confidence regarding the timing of developing and permitting CCS projects. These and related CCS financing issues are addressed in the EFI Foundation's *Energy Finance Forum (EF^3)* analysis.[10] EPA could adopt the IRA's definition of clean hydrogen. Cost-effectively reaching very low life cycle emissions is one of the biggest challenges for clean hydrogen projects. This is why the IRA created flexibility for accessing the 45V tax credit for hydrogen production with a life cycle assessment (LCA) of less than 4.0 kg CO_2e/kg H_2. EPA's proposal, however, defines "clean" as an LCA of 0.45 kg CO_2e/kg H_2, significantly impacting the cost, type, scale, and regional diversity of eligible projects. For example, EFI Foundation modeling finds the delivered cost of hydrogen in the Carolinas under EPA's proposal is around $8/kg in 2035, compared to EPA's estimate of $0.5/kg.[11] As previously mentioned, in a High H2 scenario, this policy could require 115 GW of new wind and solar projects by 2035 dedicated only to clean hydrogen production.

- **Develop clear compliance metrics, with maximum regional flexibility, for new decarbonization proposals.** EPA's proposed BSER may lack sufficient regional flexibility to reach compliance in the proposed time frames, while managing costs and reliability. Areas of the country without abundant, low-cost renewables, access to low-cost CO_2 storage, or other alternatives (e.g., existing nuclear) may see measurably higher costs when implementing EPA's proposal compared with other regions. The CAA currently supports regional approaches through a state planning process, allowing regional entities to propose optimal systems of emissions reduction for their own jurisdictions that must achieve the necessary environmental performance outlined by EPA's proposal. These State Plans cover only existing generators—Section 111(d) of the CAA—and not new builds—Section 111(b).

  Once the EPA issues its emission standards, including BSER for specific power plant types, EPA is proposing that states have 24 months to submit their own plans to EPA that are at least as stringent in terms of emission reductions as EPA's guidelines. EPA should encourage the use of State Plans, offering robust federal-state collaboration and clear metrics for how each State Plan can reach compliance (e.g., offering guidance on what qualifies as achieving the state equivalent of total emission reductions, aligned to EPA's proposal). EPA should be explicit about how each state can reach compliance. For example, EPA could clarify that emission trading regimes and technology emission performance "averaging" can be used in State Plans. EPA could also explicitly allow legislated state policies (e.g., Regional Greenhouse Gas Initiative[e]) for electricity decarbonization that meet or exceed the performance of EPA's proposal, creating a more synchronous federal and state policy environment. EPA should also consider developing a similar approach to State Plans that cover new generating units. This could help create more system-wide visibility into how each state and region is approaching electric sector decarbonization. Furthermore, EPA's proposal lacks clear community engagement guidelines, beyond best practices. Offering clear guidelines, starting with an approach like DOE's Stakeholder Engagement Plan, and directions for ensuring community involvement with future policies is critical.[12]

[e] The Regional Greenhouse Gas Initiative is a cooperative effort among 12 states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia – to reduce greenhouse gas emissions. https://www.rggi.org/

- **Create permitting reforms for rapid scaling of electricity, CO_2, and hydrogen infrastructure**. EPA's proposed rules do not fully consider the risks of permitting delays, which can be considerable when deploying FOAK technologies. Improving the permitting of new and refurbished clean energy infrastructure will require a whole-of-government effort and strong state, regional, and local partnerships. EPA should work with the White House and Congress to ensure that its decarbonization proposals reflect current permitting needs and challenges.

  There are many emerging opportunities to support improved energy permitting. Implementing the DOE Regional Clean Hydrogen Hubs (H2Hubs) program, which will require new hydrogen and CO_2 infrastructure, as well as new electricity generation and transmission, will be a major opportunity for federal and state stakeholders to develop new ways to site and permit multi-jurisdictional and multi-sectoral energy projects. The IIJA created H2Hubs to address multiple challenges facing hydrogen infrastructure development. In October 2023, DOE announced $7 billion for seven regional selectees. Regions with a hub will have an advantage to jump-starting hydrogen market formation. Some regions, such as the Southeast, Central, and Northeast, did not receive hub funding.

  Meanwhile, the scale and pace of EPA's proposal does not match DOE's hubs plan. DOE requires each of the seven regional hubs to produce between 20 kilotons (kt) and 40 kt of hydrogen per year by 2035, while EPA's policy could require as much as 32 Mt, or 700 times more, by 2038.[13] Additionally, EPA could consider hub-like structures in its proposals to limit the sizable infrastructure builds needed for individual plants across many regions of the country.

  The administration should work with Congress to develop a public-private partnership model for CO_2 storage management to avoid costly project uncertainty related to CCS and blue hydrogen,[f] as well as other decarbonization technologies (e.g., direct air capture) that depend on CO_2 sequestration. The EFI Foundation offered a similar proposal in a December 2022 report.[14]
  Also, the Federal Energy Regulatory Commission (FERC) could begin the process of regulating the blending of hydrogen into interstate natural gas pipelines, an important step for hydrogen demonstrations that aligns with FERC authority.

[f] Gray hydrogen is produced from steam methane reformation of natural gas without using carbon capture and storage technology to capture the CO_2 emitted from production. When CO_2 is captured, the resulting hydrogen is called blue. Green hydrogen is produced from electrolysis using renewable electricity (solar and wind). When nuclear electricity is used instead, it is called pink hydrogen.

Introduction and Context

Reaching net-zero targets will require unprecedented investments and innovative solutions to reduce and remove greenhouse gas (GHG) emissions while maintaining vital energy services for homes, factories, and businesses across the country and world. Climate change has increased the frequency and intensity of heat waves, heavy precipitation, and droughts, with parts of the United States experiencing heavy rains and others drought-related wildfires. These trends demonstrate the need for accelerating emissions reductions across the economy and highlight the need for climate change-resilient systems.

Due to the relatively slow pace of technological change, the next decade will likely define U.S. options for reaching net-zero GHG emissions by midcentury. The electric grid can play a crucial role in rapid economywide decarbonization. The power sector is one of the largest contributors of GHGs in the United States, responsible for 25% of the nation's total emissions in 2022.[15] Shifting to a zero-carbon electricity system can directly reduce one-quarter of U.S. carbon dioxide (CO_2) emissions today and enable additional emissions reduction through increased end-use electrification in buildings, transportation, and other sectors.

In May 2023, the U.S. Environmental Protection Agency (EPA) proposed new emissions limits for fossil fuel-fired generators in the United States at a dynamic time for the sector. Electricity emissions have fallen by 40% from 2005 to 2022, with the sector shifting heavily to natural gas and renewable energy sources.[16]

The Biden administration set a target of 100% carbon pollution-free electricity by 2035, and utilities covering nearly 80% of U.S. customers have set 100% carbon reduction targets for midcentury.[17] The administration explicitly mentioned carbon capture retrofits and existing nuclear as key pathways. The Infrastructure Investment and Jobs Act (IIJA), the CHIPS and Science Act, and the Inflation Reduction Act (IRA) offer unprecedented financial incentives for economywide and electric sector decarbonization.

This report, *How Much, How Fast: Infrastructure Requirements of EPA's Proposed Power Plant Rules,* analyzes the infrastructure needs of the proposed EPA rules for fossil-fueled power plant emissions reductions. This analysis is driven by national and regional models of the United States using the SESAME (Sustainable Energy System Analysis Modeling Environment) framework to understand the EPA proposal's cost, emissions reduction potential, energy requirements, and the electricity and energy system infrastructure needs.

This report is part of a series, the *U.S. Hydrogen Infrastructure Action Plan*, which will build on this study to recommend options for accelerating economywide hydrogen uptake.

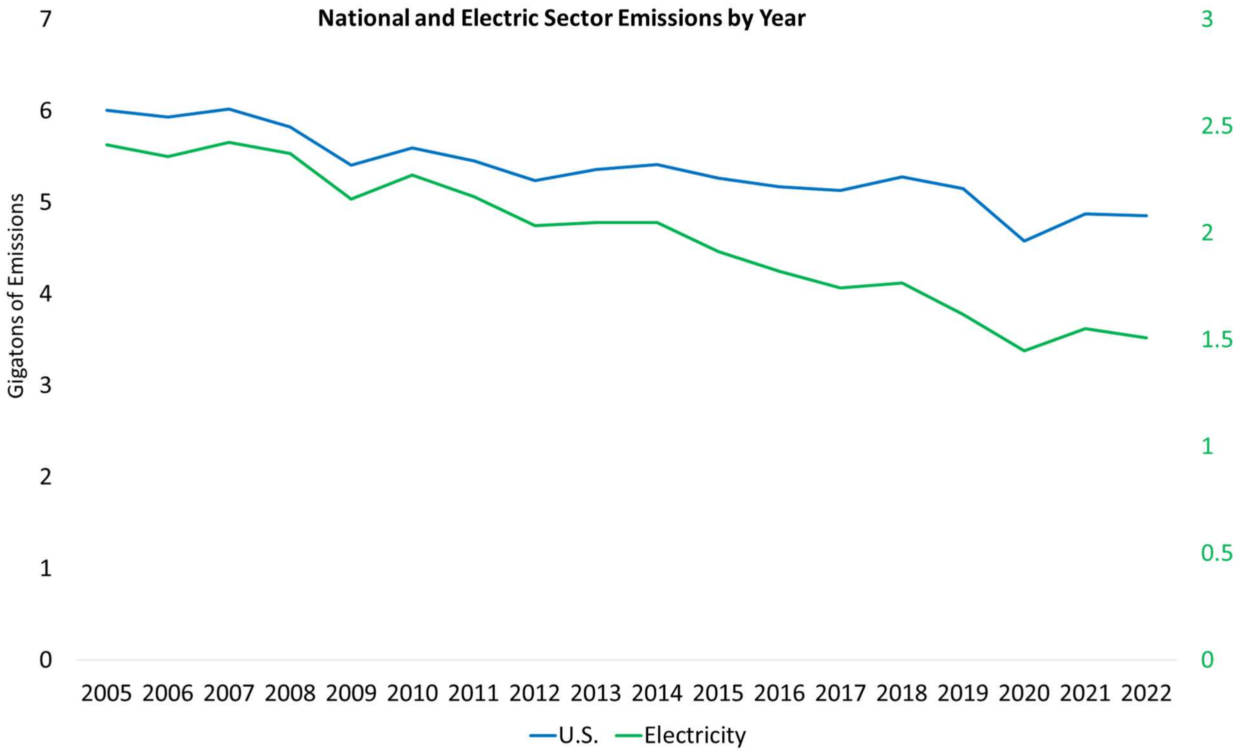
The electric grid continues to be the linchpin of U.S. decarbonization

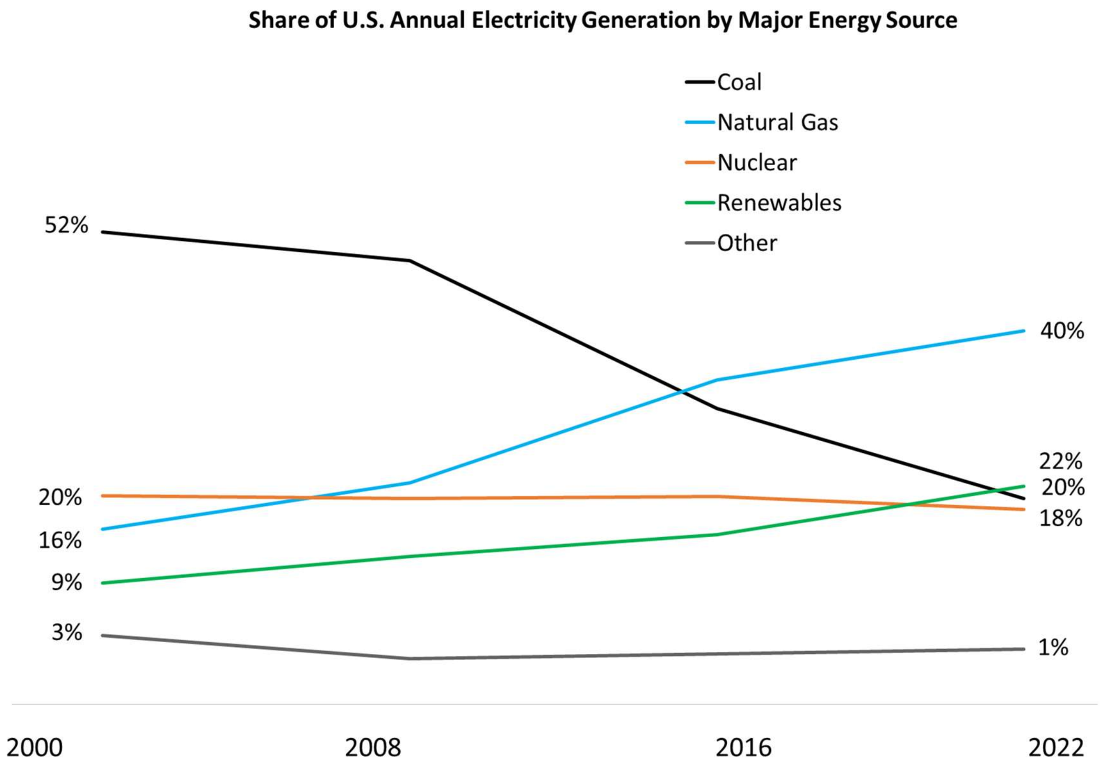
The electric grid has been the primary driver of U.S. emissions reduction in the last few decades. Electric sector GHG emissions were down 40% from 2005 to 2022, due mostly to the sector's shift from a coal-dominated system to one that relies on natural gas and renewables for 62% of total U.S. generation (Figure 1).[18]

Since 2000, gas generation has increased from 601 gigawatt-hours (GWh) to 1,689 GWh. Shifting to a zero-carbon grid can reduce roughly one-quarter of U.S. emissions, or roughly 1.5 gigatons in 2022, and enable additional emissions reductions through increased end-use electrification in buildings, transportation, and other sectors.

Figure 1.

Trends in the U.S. electricity sector





The use of natural gas and renewables in electricity generation has steadily increased since 2000, replacing coal and contributing to the electric sector emissions decreasing 40% from 2005 to 2022. Data from: See first figure mention in text for sources.

Many studies show that achieving 100% clean electricity will require a mix of resources, policies, and innovation for overcoming technical and economic barriers.[19] While grid decarbonization will require hundreds of gigawatts (GW) of new wind and solar generation, it also will depend on clean, dispatchable ("firm") power[g] and large-scale deployment of enabling infrastructure.

According to the National Renewable Energy Laboratory, electric grid decarbonization requires a massive acceleration in deployment rates and substantial development of infrastructure, including fuel storage, transportation and pipeline networks, and additional generation capacity needed to produce clean fuels.[20]

EPA's Regulatory Impact Analysis (RIA) finds that natural gas plants are expected to play an important role in the future energy mix—especially those paired with more efficient generation and emissions reductions pathways, including carbon capture and storage (CCS) and clean hydrogen blending. EFI Foundation modeling shows gas capacity will stay roughly flat through 2042 in the High H2 and High CCS scenarios but will increase measurably in

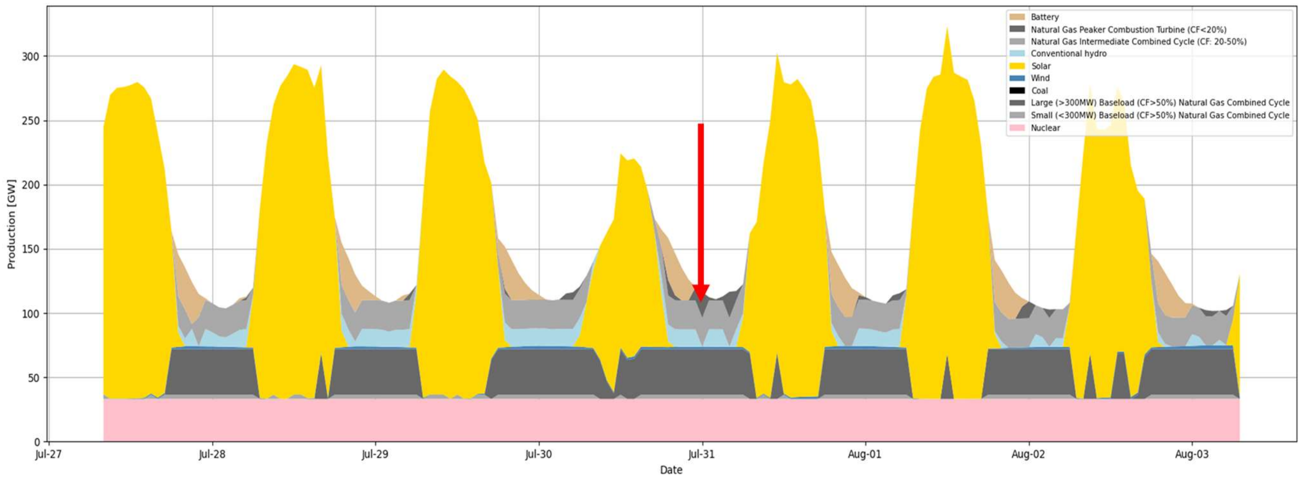
[g] Firm power is power or producing capacity designed to be available at all times.

the High RO scenario as additional small gas units come online to backfill lost generation from large units that ramp down.

Figure 2 shows the importance of gas for maintaining reliability for one region, the solar-rich Southeast, in 2042. The modeling shows natural gas (shown in gray scale) backfilling the system during daily periods of low solar output. Gas plays a major role in managing system reliability, in addition to battery storage, nuclear, and renewables.

Figure 2.

Modeling reliability in the Southeast shows important role for gas plants in 2042



Although solar energy is an abundant resource in the Southeast, natural gas peaker plants still need to be deployed to provide grid reliability when solar energy is not available. Source: EFI Foundation modeling analysis using SESAME tool.

As even more coal power plants retire throughout the country—another 50 GW of coal-fired capacity is scheduled to retire by the end of 2029[21]—and more renewables come on line, the operating profiles of existing and new gas units may change, moving down the dispatch order but remaining on-call for regular reliability support.

EPA is proposing more aggressive power sector decarbonization

On May 11, 2023, EPA proposed updating emissions reduction standards for new and existing fossil power plants using its authority under Section 111 of the Clean Air Act (CAA). The agency's Section 111 authority, which covers nearly all U.S. power sector emissions, requires EPA to create a framework for establishing national emissions standards for existing and new power plants.[22]

EPA's proposed rules address the scale of the challenge of reaching a carbon-free electric grid before midcentury though do not go as far as the Biden administration's goal of 100% carbon-free electricity by 2035.

According to EPA, its proposal would result in climate and health economic benefits of up to $85 billion and lead to cumulative emissions reductions of up to 617 million metric tons (Mt) by 2042. EPA finds that the majority (roughly 60%) of emissions reduction benefits would come from shutting down coal generation and the net reduction of building new natural gas-fired power plants with "best system of emission reduction" (BSER) emission controls. BSER encompasses highly efficient generating practices, co-firing clean hydrogen with natural gas, and CCS. The remaining benefits (roughly 40%) would come from retrofitting existing natural gas units with BSER technologies.[23] Figure 3 shows EPA's assessment of how the proposal would change the grid's energy generation and capacity mix through 2040.

Figure 3.

EPA's projected U.S. energy and capacity by fuel type from proposed rules

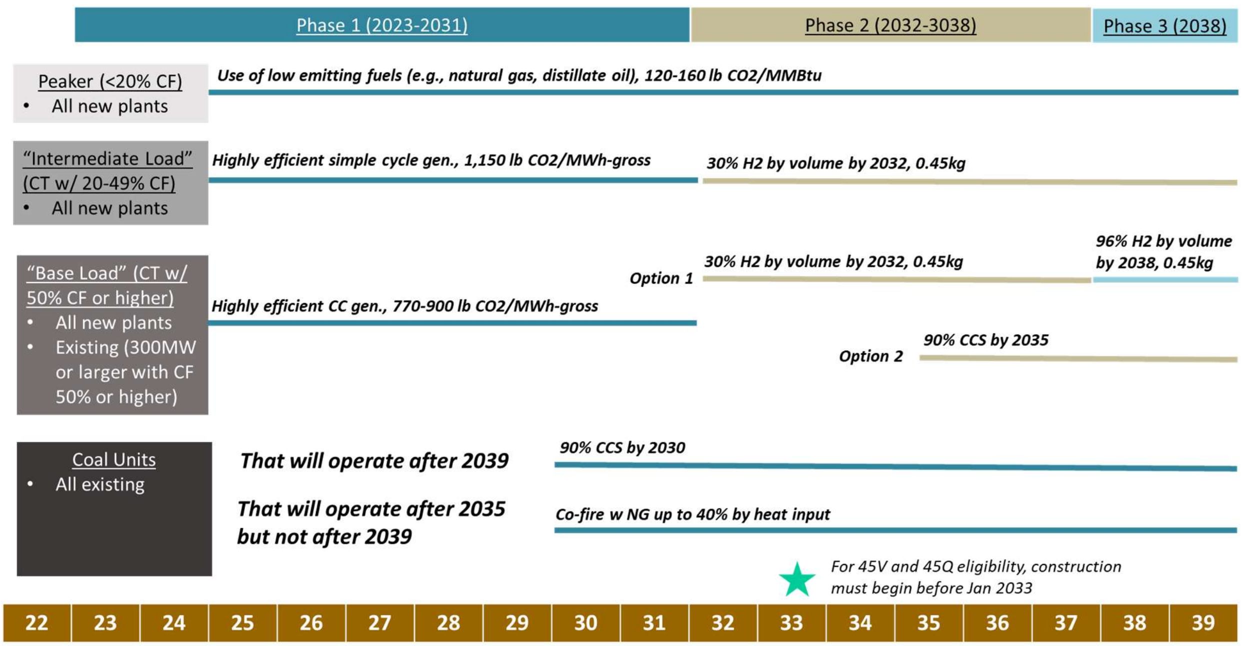
	Generation, TWh					*Capacity, GW*				
EPA proposal	***2022***	***2028***	***2030***	***2035***	***2040***	***2022***	***2028***	***2030***	***2035***	***2040***
Coal	*828*	*472*	*80*	*0*	*0*	*201*	*99*	*46*	*0*	*0*
Coal w/CCS	*0*	*0*	*85*	*85*	*65*	*0*	*0*	*12*	*12*	*9*
Natural gas	*1,689*	*1,783*	*1,846*	*1,290*	*1,044*	*520*	*467*	*460*	*476*	*512*
Natural gas w/ CCS	*0*	*0*	*31*	*66*	*54*	*0*	*0*	*4*	*8*	*8*
H_2 co-firing	*0*	*0*	*2*	*70*	*75*	*0*	*0*	*0*	*11*	*13*
Nuclear	*772*	*765*	*734*	*660*	*616*	*95*	*96*	*92*	*84*	*79*
Hydro	*262*	*294*	*303*	*328*	*346*	*100*	*102*	*104*	*108*	*110*
Renewables	*672*	*966*	*1,278*	*2,186*	*2,818*	*228*	*316*	*405*	*670*	*867*
Others (oil, etc.)	*11*	*60*	*79*	*47*	*31*	*39*	*70*	*76*	*74*	*74*
Totals	***4,234***	***4,340***	***4,438***	***4,732***	***5,049***	***1,183***	***1,150***	***1,199***	***1,443***	***1,672***
Note: 2022 data is from EIA, reporting actuals; data for 2028-2040 is from EPA RIA										

EPA's proposal requires more CO_2 emissions controls at natural gas- and coal-fired power plants that "operate more frequently and for more years and would phase in increasingly stringent CO_2 reduction requirements over time" (Figure 4).[24] The proposed requirements vary by:

- the type of unit (new or existing, combustion turbine or utility boiler, coal-fired or natural gas-fired).
- how frequently it operates (base load, intermediate load, or low load [peaking]).
- its operating horizon (i.e., planned operation after certain future dates).

Figure 4.

Timeline of EPA's proposed fossil generator rules



EPA's proposed rules for fossil fuel generators span 2023 to 2038 and encompass four categories: new peaker plants, which do not frequently operate (capacity factor, or CF, lower than 20%); new intermediate load plants (combustion turbines—CT—with CF between 20% and 49%); base load plants (CT with CF of 50% or higher), either new or existing (for the latter, capacity of 300 MW or larger); and all existing coal power plants. Each category has one or more pathways to decarbonize, depending on the time frame. Peaker plants will decarbonize using low-emitting fuels such as natural gas and distillate oil. Intermediate load plants need to increase efficiency of operating their simple cycle generation combustion turbines—measured in pounds (lb) of CO_2 per MWh-gross (which does not discount the electricity used to operate the power plant), until 2031 starting in 2032, clean hydrogen (with life cycle GHG emissions lower than 0.45 kg CO_2e/kg of H_2 produced) must be blended with the fuel used (natural gas) at a 30% rate. Base load plants also have to make their combined cycle (CC) generation combustion turbines more efficient until 2031; starting in 2032, however, they have two options to decarbonize: blending clean hydrogen with natural gas at a 30% by volume rate and then increasing that rate to 96% by 2038, or using CCS at a 90% capture rate by 2035. Coal units that will operate past 2039 need to deploy CCS at a 90% capture rate by 2030. On the other hand, coal units that will not operate past 2039 but will operate between 2035 and 2039 need to co-fire with natural gas (NG) up to 40% on a heat input basis. To be eligible for the hydrogen production tax credit (45V) or the carbon sequestration tax credit (45Q), projects need to begin construction before January 2033. Adapted from: See first figure mention in text for sources.

Overview of Section 111

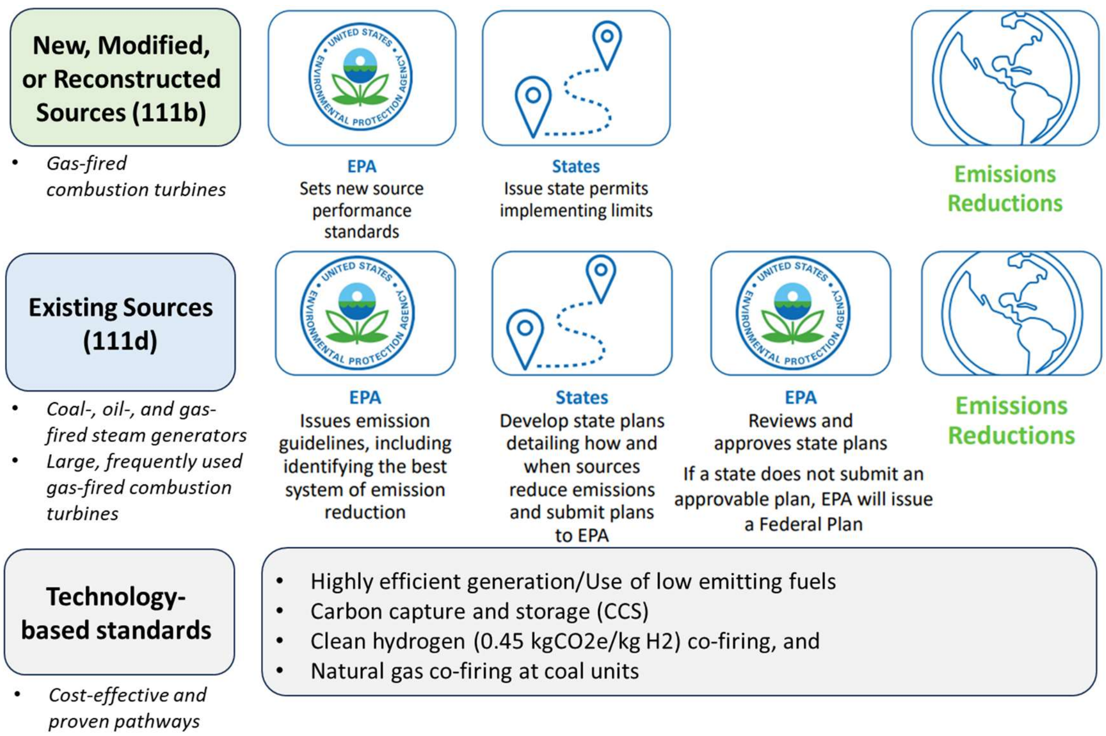
EPA is charged with developing separate emissions-reduction frameworks for new and existing power plants under CAA Sections 111(b) and 111(d), respectively (Figure 5).[25] Under Section 111, EPA can identify the types of facilities that should be regulated, distinguishing among classes, types, and sizes. The agency has considerable discretion in determining the appropriate level of emissions reduction for the standard.

For new facilities, setting emissions standards must reflect what EPA determines to be achievable through the application of the BSER, which factors in cost, non-air-quality health and environmental impacts, energy requirements, and control measures that have been adequately demonstrated.[26] Emissions standards for new plants must be reviewed at least every eight years and revised, if appropriate.

For existing facilities, EPA also uses BSER standards. Recognizing that existing sources do not have as much flexibility as new sources to build emissions controls into their design, Congress established a dynamic process for federal-state engagement on meeting the Section 111 requirements (referred to as “State Plans”). The requirements for a State Plan to be successful are, however, not clearly defined by EPA.

Figure 5.

Summary of EPA’s proposed Section 111 rules



New or existing power plants follow different guidelines to decarbonize according to EPA’s proposed Section 111 rules. New, modified, or reconstructed power plants are expected to be natural gas-fired combustion turbines. For such power plants, EPA will set emissions reduction standards and states will implement them. For existing fossil fuel power plants, *EPA and states will interact more to develop an emissions reduction strategy. The technologies that power plants will use to decarbonize are a mix of cleaner fuels (e.g., clean hydrogen, natural gas at coal units, or other low-emitting fuels), highly efficient generation, and CCS. Adapted from: See first figure mention in text for sources.*

New Gas Generators, 111(b)

EPA is proposing to update and establish more protective emissions standards for new and reconstructed fossil fuel-fired turbines, nearly all of which are expected to be natural gas-fired. EPA's proposal recognizes the growing importance of new gas-fired generators for the electric grid, especially as an enabler of increasing levels of renewable energy resources, aiming to achieve significant pollution reductions beginning in 2035.

In EPA's updated baseline scenario, factoring in systemwide benefits of IRA funding, the share of overall generation from natural gas combined cycle units increases from 36% to 40%.[27] EPA's proposal varies by different types of new gas-fired turbines, based on their level of use. The proposal includes three general subcategories:

- Low load "peaking" turbines (19% or lower capacity factor [CF])
- Intermediate load turbines (20%-49% CF)
- Base load turbines (50% or above CF)

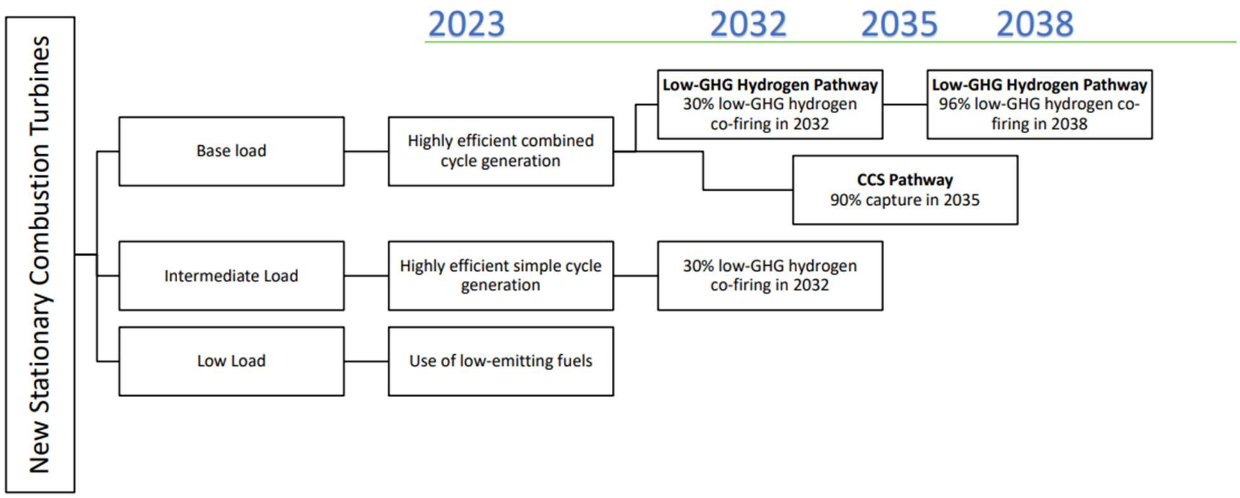
For each subcategory, EPA is proposing separate BSERs and performance standards based on the agency's evaluation of the feasibility, emissions reductions, and cost of available controls. Through 2031, the BSER for new peaking units is the utilization of "low-emitting fuels,"[h] and for intermediate and base load units, the BSER is highly efficient generation.[i] Starting in 2032, there is no additional requirement for peaking units. Intermediate and base load units have the option to employ either co-firing with clean hydrogen or CCS with 90% capture starting in 2032 and 2035, respectively. For the clean hydrogen pathway, there will be a ramp-up of co-firing from 30% by volume in 2032 to 96% by volume in 2038 (Figure 6).[28] EPA's proposal defines "clean" hydrogen as having a life cycle analysis (LCA) of 0.45 kilograms (kg) CO_2e/kg H_2.

[h] Up to 160 pounds CO_2/MMBtu

[i] Intermediate load: 1,150 pounds CO_2/MWh-gross; base load: 770 pounds CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or more or 770 pounds CO_2/MWh-gross for units with a base load rating of less than 2,000 MMBtu/h

Figure 6.

EPA proposal for new gas-fired turbines



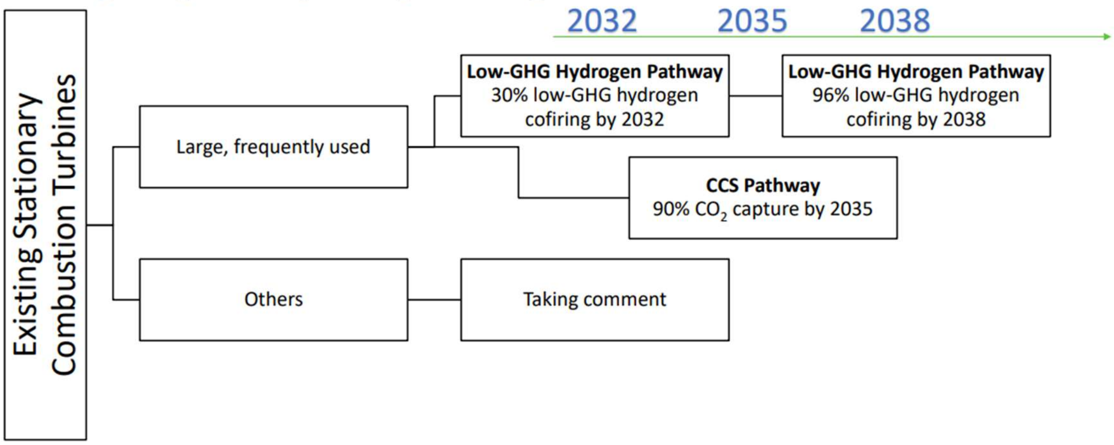
The rules to decarbonize new natural gas power plants vary according to frequency of use. Starting in 2023, low load (or peaker) power plants must use low-emitting fuels. In the same time frame, intermediate load power plants must increase the efficiency of their simple cycle combustion turbines. Starting in 2032, however, these units must blend clean hydrogen with natural gas at a rate of 30%. Base load plants must also employ highly efficient combined cycle combustion turbines starting in 2023. These units, however, can choose between two pathways to keep decarbonizing: In the first one, clean hydrogen co-firing at a rate of 30% must start in 2032, ramping up to 96% in 2038; if the second pathway is chosen, CCS at a capture rate of 90% must be deployed. Adapted from: See first figure mention in text for sources.

Existing Fossil Units, 111(d)

EPA is proposing separate guidelines for existing natural gas and coal generators. Existing gas power plants account for 40% of current electricity production and 43% of the sector's current GHG emissions. Recognizing that many existing gas units will be in service for decades, EPA is proposing emissions guidelines for frequently used facilities that are larger than 300 MW and have a capacity factor of greater than 50%. The BSER for these gas units is the same as the proposal for base load facilities under 111b, namely deploying either CCS with 90% capture by 2035 or co-firing clean hydrogen with natural gas at 30% by volume starting in 2032 and ramping up to 96% by volume in 2038 (Figure 7).[29] EPA is soliciting comments on how to approach all other existing facilities.[30]

Figure 7.

Existing large, frequently used gas-fired turbines



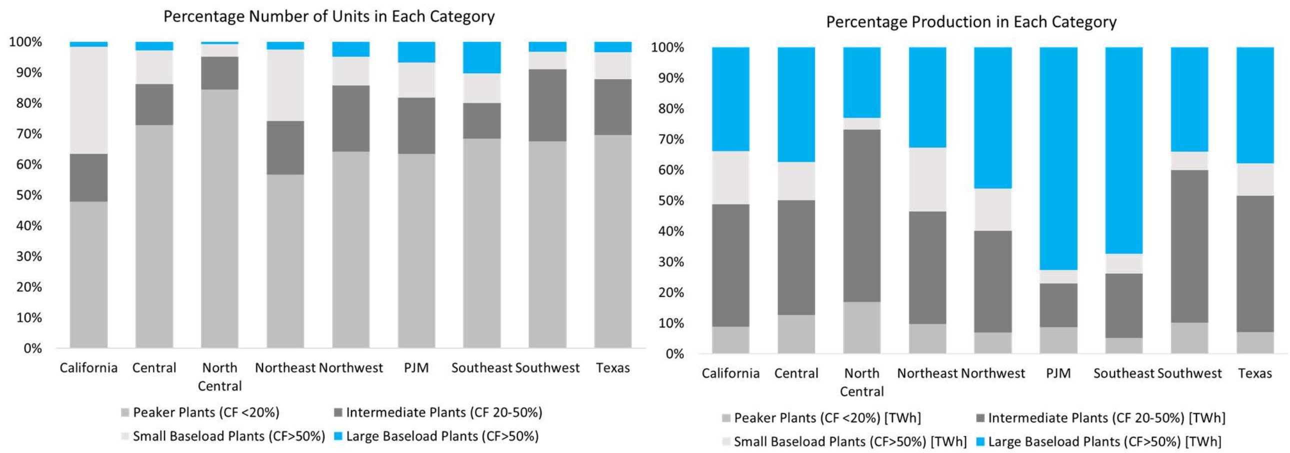
Large, frequently used existing combustion turbine power plants can choose between two pathways to decarbonize. In the first one, clean hydrogen co-firing at a rate of 30% must start in 2032, ramping up to 96% in 2038. With the second pathway, CCS at a capture rate of 90% must be deployed. For other types of existing stationary combustion turbines, EPA is currently soliciting comments about how to decarbonize those units. Adapted from: See first figure mention in text for sources.

There are roughly 200 existing gas units covered by EPA's proposal,[j] accounting for only 20% of total U.S. generation capacity. These units generate between 20% and 70% of the gas-fired generation in each region of the country (Figure 8).[31] Theoretically, base load facilities can reduce operations to below 50% CF to receive intermediate load status; however, this is a business and operational decision that would need to be weighed against the alternatives and could result in incentivizing building new peaker plants that do not require a BSER.

[j] Accounting for unit size (>300 MW) and capacity factor requirements (>50%)

Figure 8.

Number of gas units and regional share of generation impacted by EPA's proposal



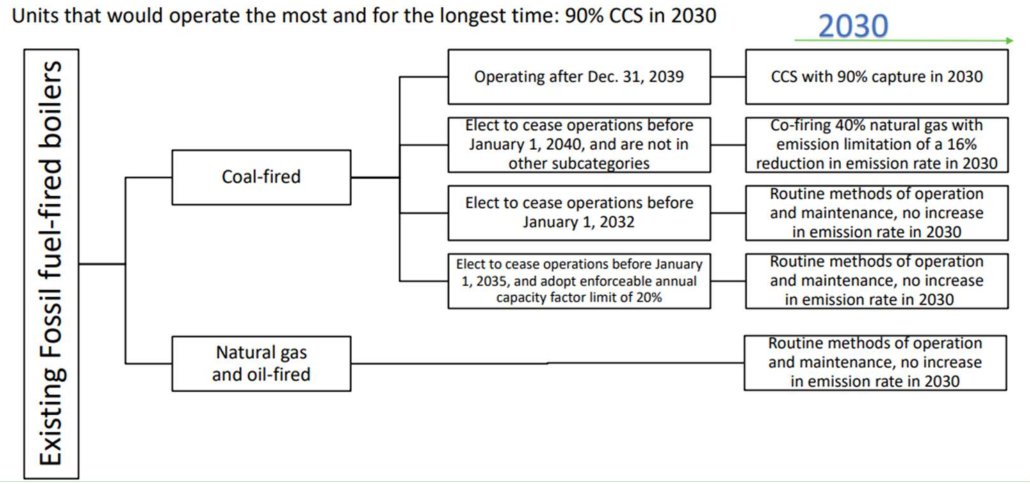
Most natural gas units in the country are peaker power plants. Large base load and intermediate plants, however, are responsible for most of the natural gas electricity generation in the United States. Source: See first figure mention in text for sources.

EPA is also proposing standards for existing coal-fired steam generators, based on the expected operating life of the unit (Figure 9).[32] According to EPA, in response to industry input and recognizing that the "cost-effectiveness of CO_2 controls depends on the period of time over which a plant will be operated," the agency is proposing separate BSERs depending on when the coal unit plans to permanently cease operation.[33] For facilities that will operate in the long term (i.e., after December 31, 2039), the BSER is the use of CCS with 90% capture rates. For any coal-fired unit that plans to permanently cease operations before then, EPA is proposing standards across three general categories:

- Medium-term: Units that commit to permanently cease operations before January 1, 2040.
- Near-term: Units that commit to permanently cease operations before January 1, 2035, and operate with an annual CF limit of 20%.
- Imminent-term: Units that commit to permanently cease operations before January 1, 2032.

Figure 9.

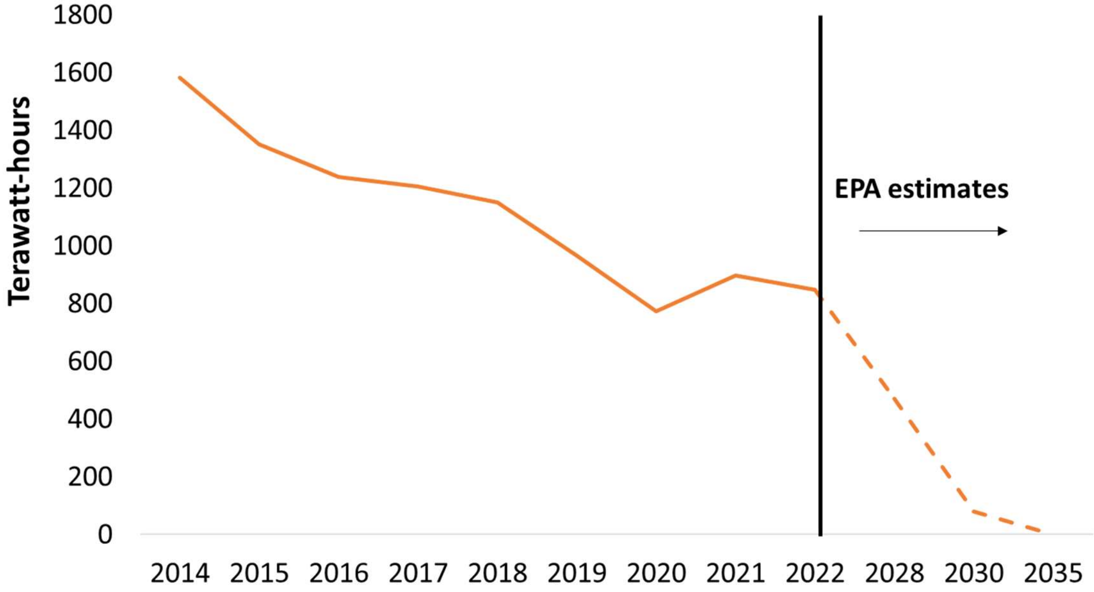
Existing fossil fuel-fired steam generators



For existing fossil fuel-fired steam generators (or boilers), decarbonization pathways depend on the fuel used. For natural gas and oil-fired steam generators, periodic maintenance must ensure that the emissions rate does not increase in and past 2030. The same criteria apply to coal-fired generators that decide to cease operations in 2032 and 2035. The latter also must enforce an annual capacity factor limit of 20%. Coal-fired boilers that decide to cease operations before 2040 and do not fit in other categories must co-fire with natural gas at a rate of 40% and must ensure that the emissions rate is reduced by 16% in 2030. Coal-fired boilers that will continue to operate past 2039 must adopt CCS with a 90% capture rate in 2030. Adapted from: See first figure mention in text for sources.

EPA's RIA shows its proposal would drive a rapid shift away from coal-fired generation (Figure 10). Roughly 830 TWh (200 GW) of coal generation would come offline between 2022 and 2035, driving sizable emissions reductions (roughly 1 gigaton) from the power sector.[34] To put this scale into perspective, total wind and solar generation was 400 TWh in 2022.[35]

Figure 10.
Historic coal generation and EPA's estimated impact of proposed rules



EPA estimates that the proposed rules would shift the power sector away from coal-fired generation by 2035, with roughly 830 TWh of coal generation coming offline.

State Plans

Section 111(d) of the CAA provides for dynamic federal-state collaboration in securing emissions reductions from existing power plants, with flexibility for states to identify their own optimal systems of emissions reduction while achieving the necessary environmental performance. According to EPA, once the final emission standards are issued, including the BSER for specific power plant types, states have 24 months to submit their own plans to EPA that are at least as stringent in terms of emissions reductions as EPA's guidelines.

This process is designed to give states the flexibility to consider regional factors when applying performance standards, possibly leading to different approaches to emissions reduction than the BSER identified by EPA. According to EPA, these State Plans can ensure that priorities, concerns, and perspectives of communities are heard during the planning process.[36] If EPA determines the State Plan inadequately meets the BSER standard, the agency must develop and implement a state-specific plan.

Tribes

Under Section 111(d), tribes may seek authority to implement their own plans, similar to a state. Tribes may choose to develop a Tribal Implementation Plan (TIP), offering the same flexibility as State Plans. If a tribe does not seek and obtain authority from EPA to establish a TIP, the agency has the authority to establish a federal plan for the tribe's areas where designated facilities are located.[37]

Communities

EPA's RIA offers suggestions for how its proposal can mitigate negative impacts to certain communities, including populations of concern in terms of environmental justice (EJ) and front-line groups. While EPA recognized that environmental justice concerns are "unique and should be considered on a case-by-case basis," the following questions should guide impact assessments:

1- Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?
2- Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
3- For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?"

Per the RIA, meaningful involvement of communities requires that: 1) "potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health," 2) "the public's contribution can influence the regulatory agency's decision," 3) "the concerns of all participants involved will be considered in the decision-making process," and 4) "the rule-writers and decision-makers seek out and facilitate the involvement of those potentially affected."

To begin analysis on community impact, EPA suggests a review of literature and prior community feedback concerning factors that make a given population more vulnerable to environmental harms, with analyses grouped into 1) baseline, or current distribution of exposures, risk, and disparities, and 2) policy, or distribution of exposures, risks, and disparities after the regulatory option has been applied.

Analyzing EPA's Proposed Rules for Decarbonizing Fossil Generators

EPA's proposal depends on sizable deployments, in the next decade and beyond, of electric infrastructure, CCS and clean hydrogen systems with relatively complex value chains. The scalability, cost, and timing of deployment of these technologies will be driven by the availability of their enabling infrastructure.

To evaluate these complex infrastructure issues, EFI Foundation used the SESAME platform, which combines technology deployment modeling with energy infrastructure analysis. National and regional energy system model scenarios were designed to evaluate EPA's proposal in terms of energy and capacity requirements, infrastructure needs, and systemwide costs.

Strategic takeaways

EFI Foundation modeling and research resulted in three major insights that may inform EPA's approach to its proposed rules for lowering emissions from existing and new fossil generators:

- CCS and clean hydrogen face first-of-a-kind (FOAK) challenges to deployment that must be addressed for at-scale deployment in the next decade.
- Meeting EPA's proposed rules will require major energy infrastructure builds development across the country that will not be ready in time for generators to comply with EPA's proposal without overhauls to project permitting regimes.
- The proposed BSERs are not available equally across the country, leading to regional variation in terms of system costs and the net emissions benefits that should be addressed.

Modeling Approach

EFI Foundation used the SESAME platform to evaluate options and impacts of technological, operational, temporal, and geospatial characteristics of the transitioning energy system.[38] SESAME focuses on the accurate estimation of life cycle GHG emissions, techno-economic assessment, and the scalability and feasibility of emerging technologies.

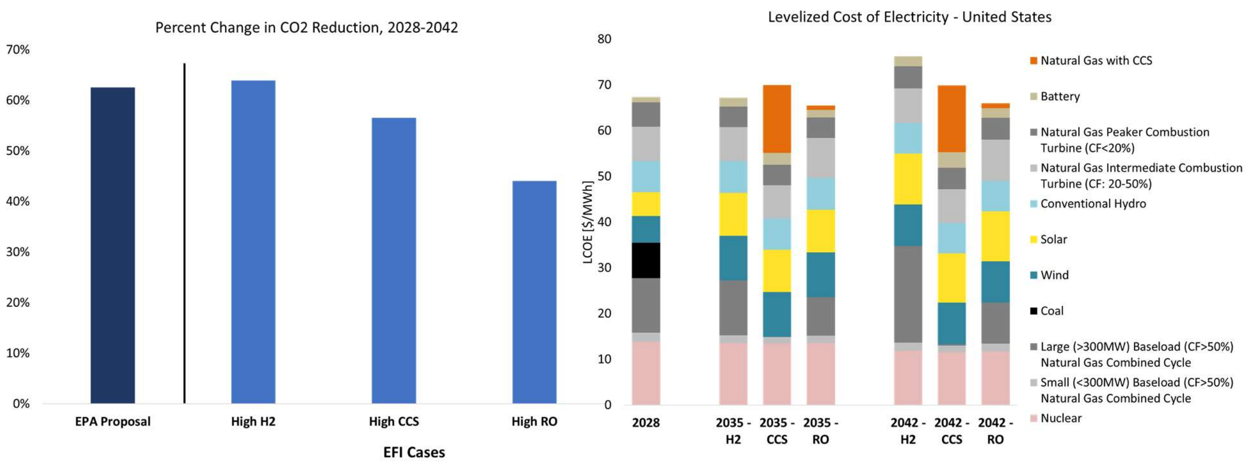
National and regional model scenarios were created to profile the systemwide impacts of meeting EPA's proposal in 2028, 2035, and 2042. This analysis used the U.S. Energy Information Administration's *Annual Energy Outlook 2023 Reference Case* for power demand forecasts and generation profiles for all technologies.[39] A deep-dive analysis was performed on natural gas and coal units—the focus of EPA's proposal—to understand their current operational profiles by region using EPA's Emissions & Generation Resource Integrated Database (eGRID).[40] This is important as EPA's proposal affects natural gas plants based on their size and capacity factors.

Three modeling scenarios, each focused on the major elements of EPA's proposal, were developed to understand a range of potential impacts on the system by 2028, 2035, and 2042: 1) high hydrogen demand ("High H2"), 2) high CO_2 capture rates ("High CCS"), and 3) high reduced operations ("High RO"), which refers to the option for large, frequently run power plants to lower their CF to reduce their policy compliance costs.

The modeling results show the proposed rules could lead to a range of emissions reductions and levelized electricity costs, depending on the scenario (Figure 11). In the High H2 scenario, the overall emissions benefits are slightly higher in terms of the percentage of CO_2 reduction than in EPA's proposal and nearly 20% higher than in the High RO scenario. One reason why: In the High RO scenario, as large units reduce operations to comply with the policy, new, smaller gas units not covered by the policy come on line, resulting in emissions. The levelized cost of electricity (LCOE) also varies by scenario over time, with major cost increases in renewables and the rapid shift to CCS and clean hydrogen in the power sector.

Figure 11.

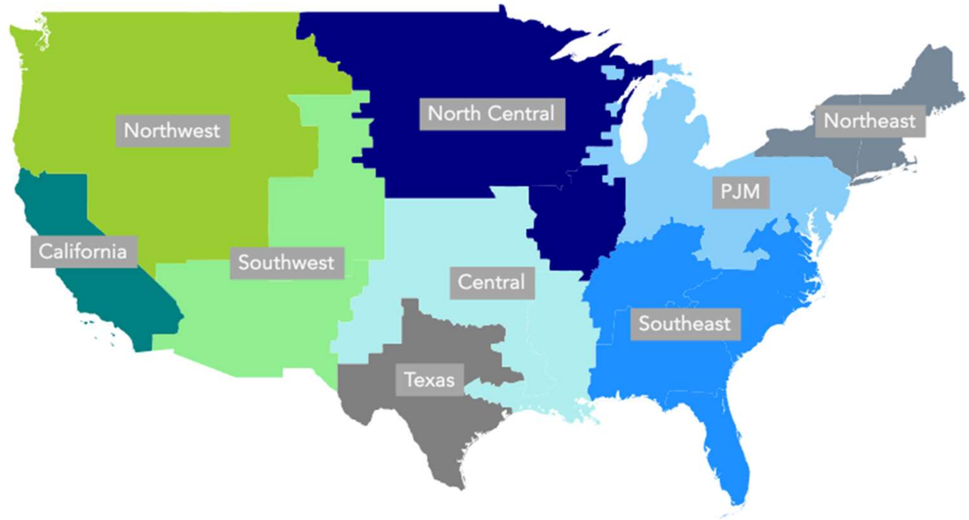
Comparing CO_2 reduction and electricity cost estimates of EPA's proposal



On the left, the percentage change in CO_2 emissions reduction between 2028 and 2042 can be 20% higher between the High H2 and High RO scenarios. Percent reduction was used rather than absolute terms as EPA's baseline year (2028) assumed a large increase in gas-fired generation from 2022, before a large reduction by 2042. EFI Foundation modeling used different assumptions, making a comparison on absolute terms possibly misleading. The graph on the right shows the contribution of each generation technology to the levelized cost of electricity in each scenario in 2035 and 2042. Only grid costs are included. Source: EFI Foundation modeling analysis using SESAME tool.

For each scenario, hourly electricity dispatch was modeled for 2028, 2035, and 2042 in each of the nine regions, delineated by EIA zones, which combine North American Electric Reliability Corporation (NERC) and independent system operator (ISO) regions (Figure 12). Integrated hydrogen and CCS models were used to assess the infrastructure requirements of the policy proposal.

Figure 12.
Map of modeled regions



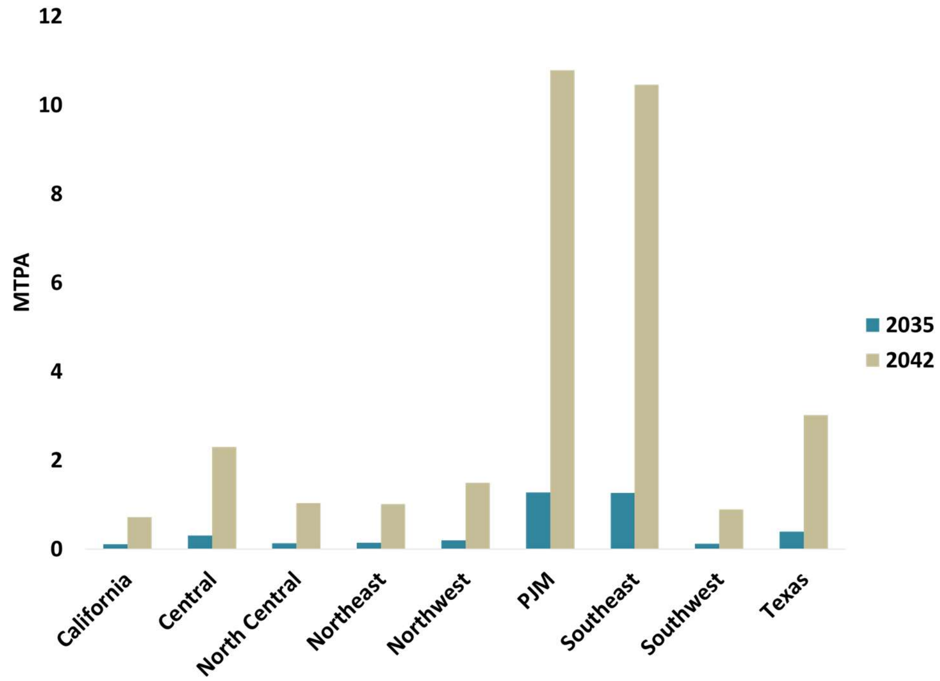
In this analysis, the United States was divided into nine regions following the EIA zones, which combine the NERC and ISO regions. Source: EFI Foundation modeling analysis using SESAME tool.

High Hydrogen Scenario

In the High H2 scenario, each region was constrained to only the hydrogen pathway. All new and existing (300 MW and larger) base load units (50% CF or higher) adopted co-firing hydrogen by 30% by volume in 2032, and 96% by 2042 to comply with EPA's proposal. All new intermediate load units employed 30% co-firing starting in 2032. As the results show (Figure 13), U.S. regions with a larger number of these assets demand more hydrogen than other regions. Annual hydrogen demand would grow substantially by 2042 to more than 32 Mt, aligned with EPA's proposal. For reference, there is effectively no clean hydrogen produced or consumed in the United States today.

Figure 13.

Annual hydrogen demand by region in High H2 case, 2035 and 2042



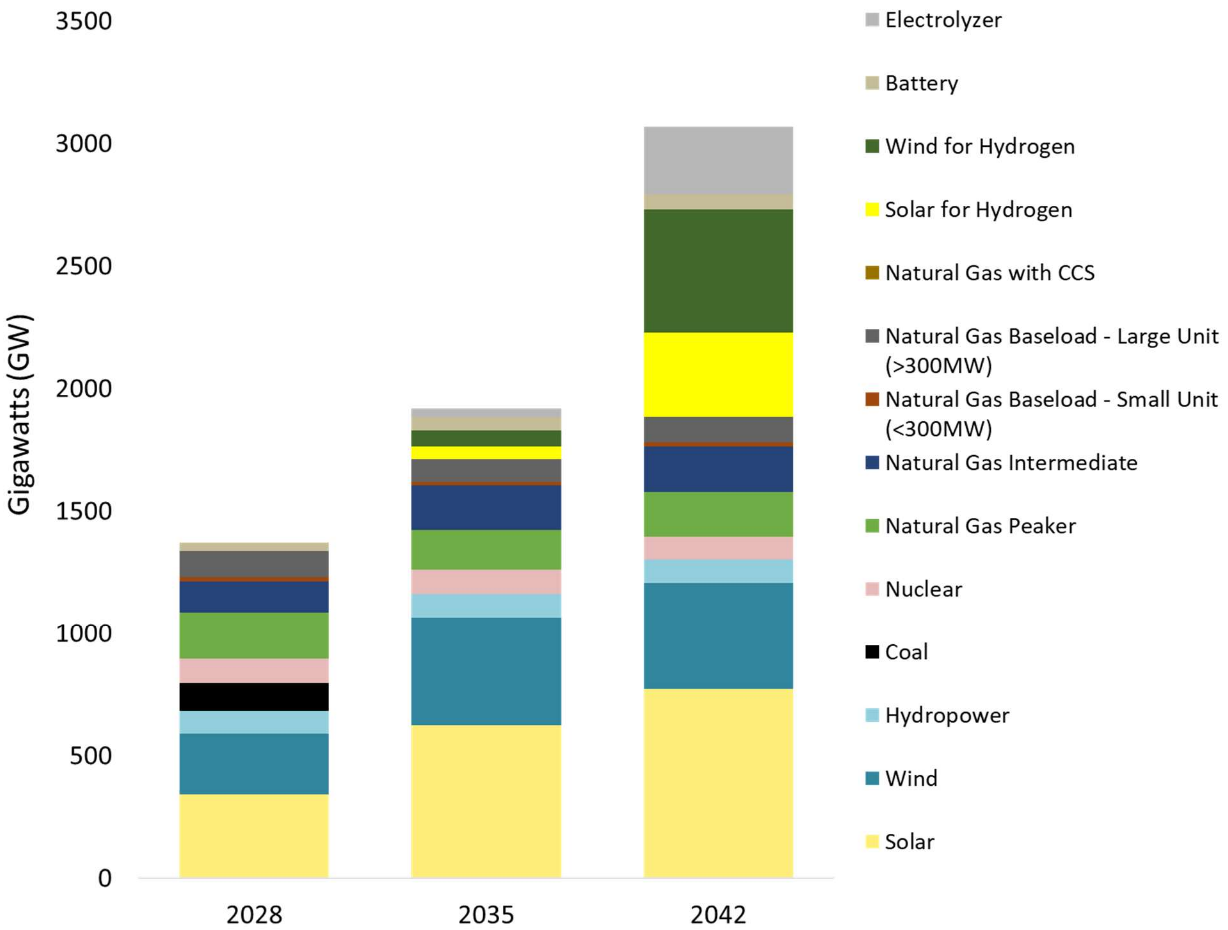
Only the clean hydrogen pathway is a decarbonization alternative in the High H2 scenario. Clean hydrogen demand in 2042 reaches more than 32 million metric tons per year (MTPA). Source: EFI Foundation modeling analysis using SESAME tool.

Figure 14 shows electric grid capacity by technology in the High H2 scenario. EFI Foundation projects 30% hydrogen co-firing on 105 GW of gas-fired generation by 2035 and 96% co-firing on 124 GW by 2042, substantially higher than EPA's estimates of 11 GW and 13 GW, respectively.

To produce the clean hydrogen, 115 GW of dedicated renewables are needed in 2035 and 850 GW by 2038. EFI Foundation's modeling shows that EPA's proposal would likely drive all coal generation out of the system by 2035 because of the timing and cost challenges of deploying CCS on coal by 2030. Hydrogen demand is factored in according to the policy requirements, and battery storage is incorporated to help manage hourly reliability needs by region.

Figure 14.

Installed capacity in High H2 case



Coal generation is phased out of the system by 2035 in the High H2 case. Because the rate of hydrogen blending increases substantially between 2035 and 2042, renewables' installed capacity (solar and wind) to produce clean hydrogen also grows. Source: EFI Foundation modeling analysis using SESAME tool.

One state-level example illustrating the modeling approach is Arizona, which depends on natural gas (42%), nuclear (29%), coal (12%), solar (10%), hydroelectricity (5%), and wind (1%) for its power system capacity and generation. [41] EIA's *AEO Reference Case* forecasts large decreases in coal and gas generation, matched in part by increases in wind and solar, and stable hydro and nuclear through midcentury.

Modeling of the High H2 scenario shows similar trends for coal and nuclear, though increases in natural gas by 2042, to cover the lost coal capacity and generation. There are increases in intermediate (16%) and peaker (10%) units that have lower or no policy requirements.

Meanwhile, new dedicated renewables for hydrogen production would exceed the region's grid-connected wind and solar by 2042. This is driven by the EPA's proposed requirement of

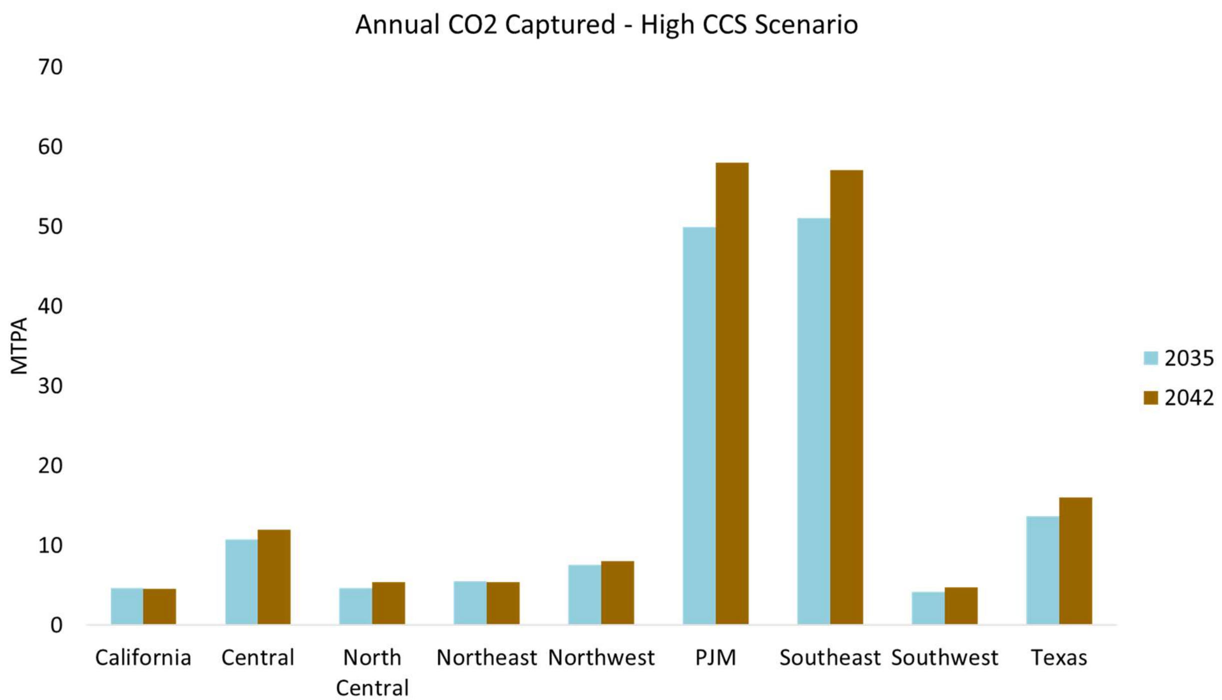
0.45 kg CO_2e/ kg H_2, as only renewables are assumed to be producing hydrogen. In the other scenarios, described below, the overall system capacity is smaller, though similar dynamics exist where new smaller, gas capacity is needed to cover large lost coal.

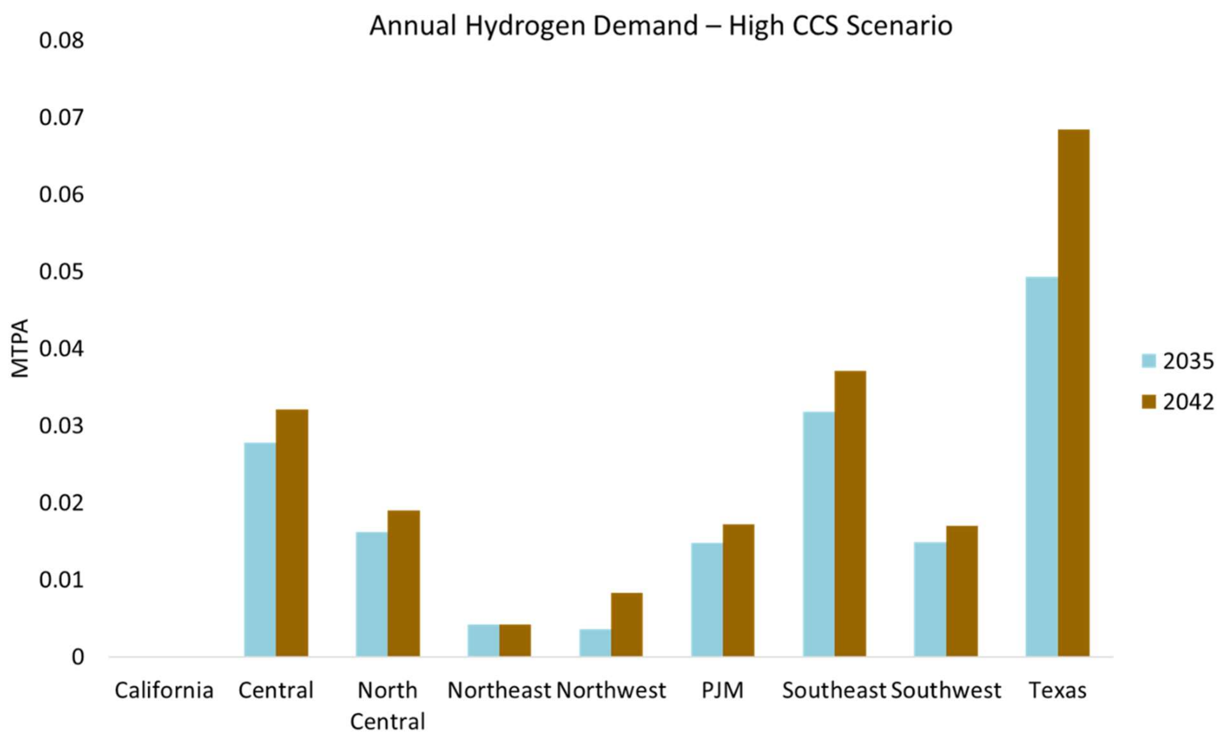
High CCS Scenario

In the High CCS scenario, all base load units adopt CCS by 2035, per EPA's proposal, while new intermediate load units deploy 30% hydrogen co-firing in 2032. Using the EIA's *Annual Energy Outlook 2023 Reference Case* as a baseline, the SESAME model solved for grid reliability in 2028, 2035, and 2042. The results show that roughly 170 Mt per year of CO_2 would need to be captured by 2042 in this scenario (Figure 15). Hydrogen demand in the High CCS case is around 0.2 Mt per year by 2042, closer to EPA's estimate of hydrogen demand in its proposal: 0.32 Mt per year by 2040.

Figure 15.

CO_2 captured and H_2 demand in High CCS case

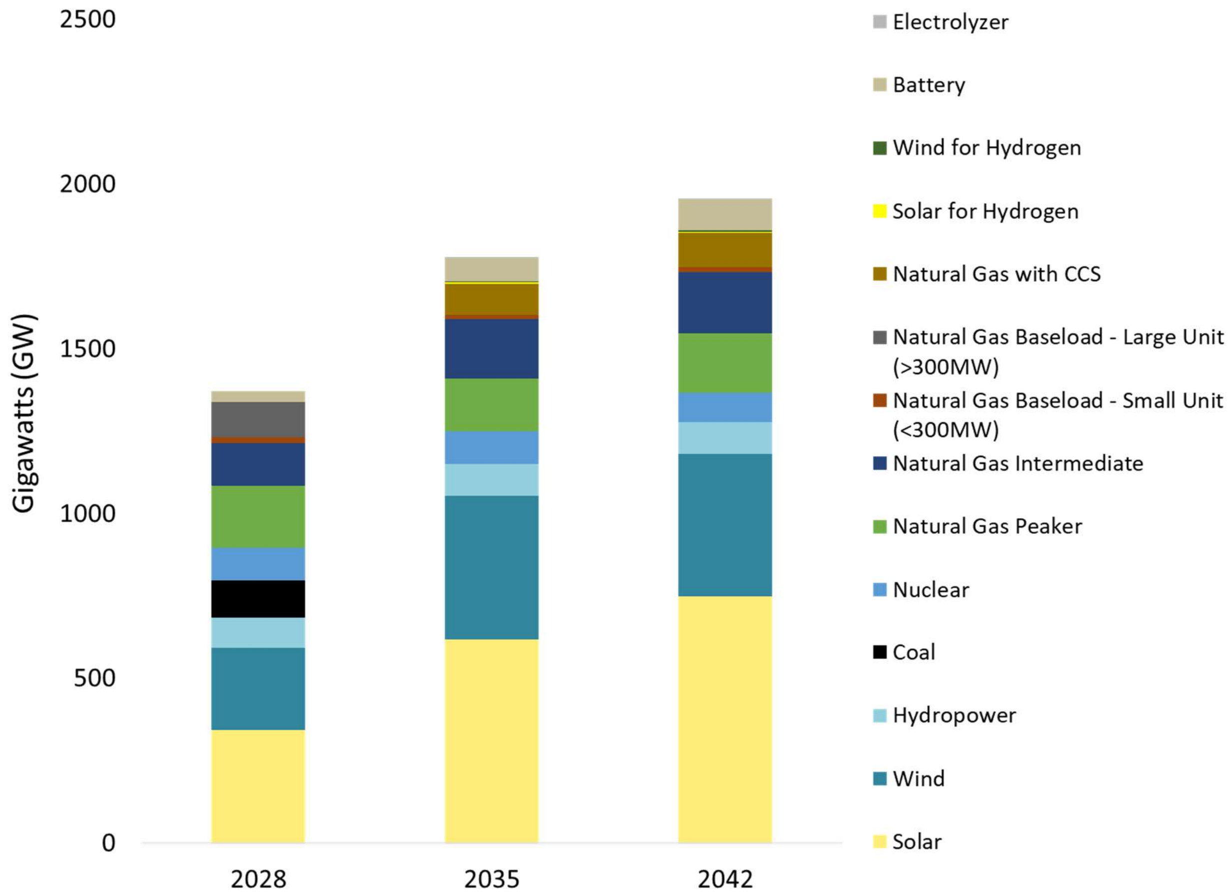




In the High CCS case, CO_2 is mostly captured in regions where large plants are located (PJM, Southeast). Hydrogen is demanded by intermediate load plants to co-fire with natural gas in regions where these plants are mostly located (e.g., Texas). Because CCS is a viable option, hydrogen demand in this scenario is closer to EPA's estimates. Source: EFI Foundation modeling analysis using SESAME tool.

Figure 16 shows the electric grid capacity by technology in the High CCS case. EFI Foundation projects CCS on 94 GW of gas-fired generation by 2035 and 105 GW by 2042. Using EIA's *Annual Energy Outlook 2023 Reference Case* as a baseline, covering the lost coal capacity is done through CCS at natural gas plants, hydrogen co-firing at intermediate load units, increases in renewables, and battery storage. Hydrogen demand is factored in according to the policy requirements, and battery storage is incorporated to help manage hourly reliability needs by region.

Figure 16.
Installed capacity in High CCS case



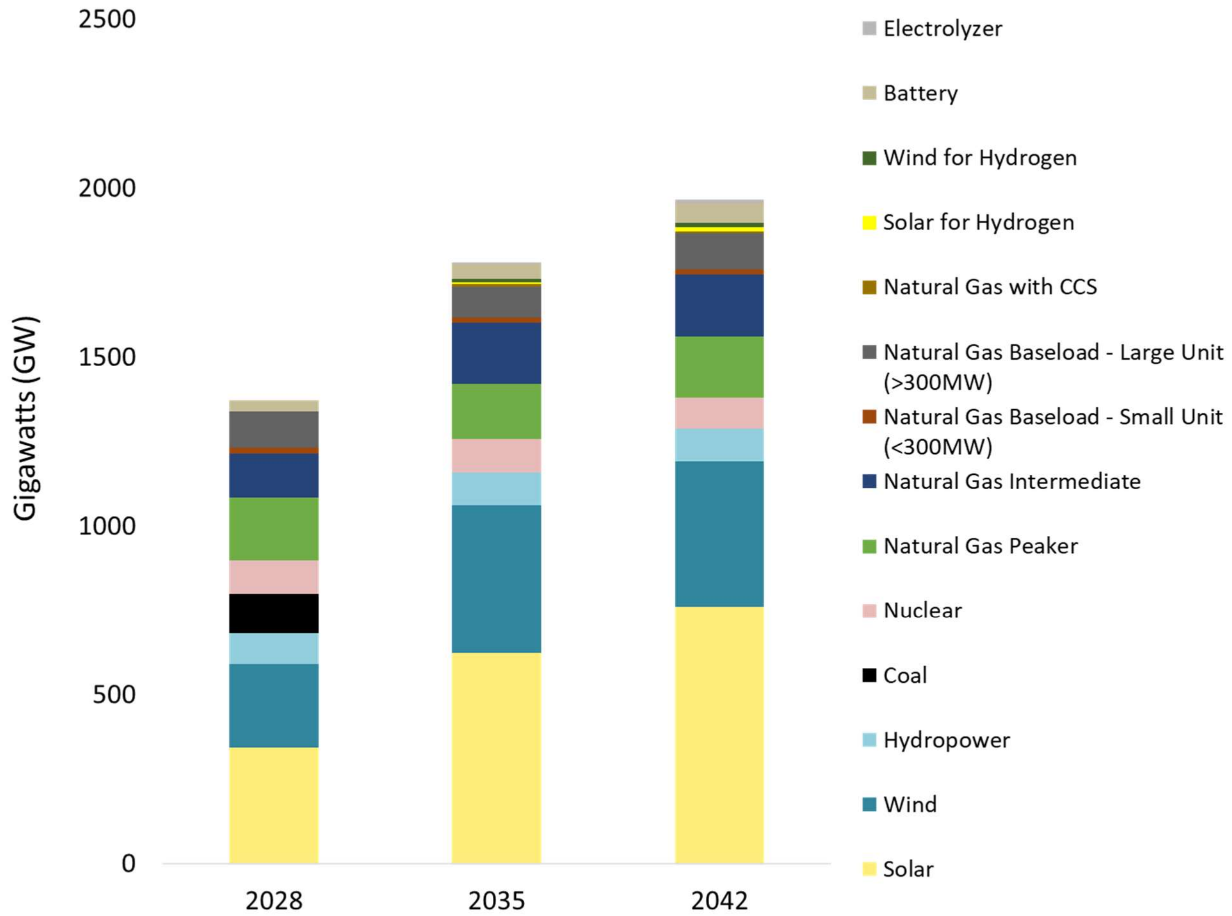
Coal is replaced by natural gas with CCS in the High CCS case, as well as hydrogen co-firing at intermediate load units, increases in renewables, and battery storage. Renewable capacity to produce hydrogen is not substantial because hydrogen demand is not extensive. Source: EFI Foundation modeling analysis using SESAME tool.

High Reduced Operations Scenario

Because EPA's proposal covers facilities based, in part, on the type of unit (e.g., combustion turbine or boiler) and how frequently it operates (base load, intermediate load, peaker), certain types of plants can change how they operate to adjust their policy compliance needs. The decision for large (at least 300 MW) base load units (50% or CF) to ramp down operations to be classified as an intermediate load unit (20%-49% CF) would be based on an array of factors, including how many hours per year of reduction is needed and the cost of backfilling the lost generation.

To model this in the High RO scenario, all large base load units reduce operations to 49%. To help cover the resulting supply shortfall of roughly 100 TWh in 2042, it is assumed that all intermediate load units ramp up operations to 49% CF. The SESAME model chooses the cost-optimal resources to fill the remaining gap to cover reliability at an hourly resolution. While there may be no clear market signal for the intermediate units to ramp up, the lost generation from the large base load units could create a large supply shortfall and serious reliability concerns. Figure 17 shows the electric grid capacity by technology in 2042 in the High RO scenario.

Figure 17.
Capacity by technology in High RO case



In the High RO case, base load units reduce operations to 49% CF to classify under the intermediate load rules. To ensure supply, all intermediate load units in the system also ramp up to 49% CF. As a result, natural gas plants have a higher participation in capacity than in the other scenarios. Source: EFI Foundation modeling analysis using SESAME tool.

Policy Analysis and Insights

EPA's proposal sets deployment targets for emerging technologies, namely CCS and clean hydrogen, that will play a major role in economywide decarbonization. The United States has the industries, workforce, and resources to scale both CCS and clean hydrogen—

possibly to gigaton-scale emissions reductions. The Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) invested heavily in these decarbonization pathways, jump-starting their development.

However, the EPA proposal's deployment time frames—2030 for 90% capture on coal plants, 2032 for 30% co-firing of hydrogen with natural gas, and 2035 for 90% CCS capture rates—combined with the lack of commercial projects today present major challenges for immediate national scaling without complementary actions and policies. The following sections show the major insights from EFI Foundation modeling and analysis that may inform EPA's approach to decarbonizing existing and new fossil generators.

Power sector applications for CCS and clean hydrogen face first-of-a-kind project costs

The EPA's cost assumptions for natural gas with CCS and delivered clean hydrogen may not include the first-of-a-kind (FOAK) costs that reflect the engineering, policy, and financial challenges of both technologies. For natural gas with CCS, EPA assumes $85/metric ton (t) for new builds and $95/t for retrofits. For clean hydrogen, EPA assumes $0.5/kg for delivered clean hydrogen starting in 2032. EFI Foundation projects FOAK costs for CCS for gas generators may be up to 40% higher than EPA's estimates, while average U.S. delivered hydrogen costs could be up to 20 times higher.

While FOAK costs are much higher than those of n^{th}-of-a-kind—technologies in market deployment stage—early movers across multiple CCS and clean hydrogen applications are critical for starting the learning process. Without these early movers, necessary cost reductions will not appear and commercial liftoff in the time frames proposed by EPA will be challenging. EPA can begin to support this by aligning its proposals to IRA requirements for CCS and clean hydrogen.

Carbon Capture and Storage Costs

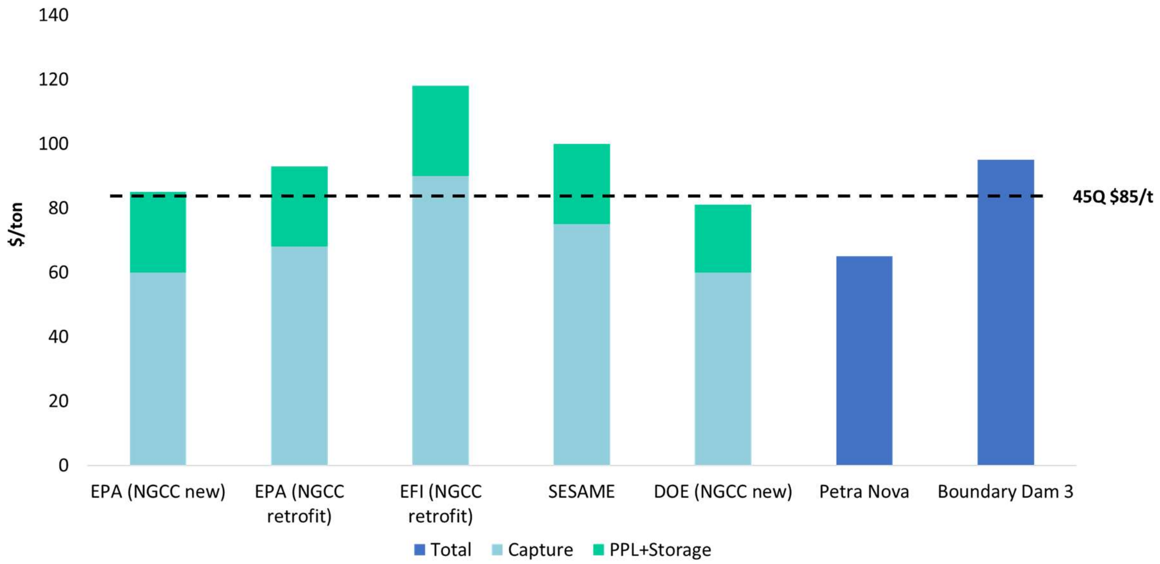
The United States has a long history of demonstrating post-combustion carbon capture. The Petra Nova CCS project, located in Houston, was a coal-fired plant retrofitted with CCS in 2017. It was one of the largest CO_2 capture projects in the world, using the CO_2 for enhanced oil recovery. The project ceased operations in 2020. Currently, there are at least nine announced CCS Front-End Engineering Design (FEED) studies on natural gas combined cycle power plants, mostly focused on improving the capture technology on a performance and cost basis.[42] Bringing these projects on line will be critical for driving down project costs.

Cost gaps need to be overcome to support the deployment of these projects. First, the 45Q tax credit—the primary federal policy supporting CCS in the U.S.—may not cover FOAK costs for CCS in power generation. The IRA made considerable improvements to the 45Q tax credit, including increasing its value from $50/t to $85/t. However, EFI Foundation estimates FOAK costs for CCS for gas and coal generators at $110/t to $120/t and $100/t to

$110/t, respectively, much higher than the expanded 45Q tax credit value of $85/t (Figure 18).[43]

Figure 18.

Comparison of CCS project costs



Although the IRA has increased the value of the 45Q tax credit to $85/t of CO_2 captured, it does not fully cover the cost of retrofitting natural gas combined cycle (NGCC) and coal power plants with CCS technologies, whose costs are around $110/t-$120/t and $100/t-$110/t, respectively. Source: See first figure mention in text for sources.

First-mover projects will need to cover FOAK costs to support industry learning and build investor confidence in each commercial setting. Those costs range between 20% and 30% of the total project cost, according to the National Energy Technology Laboratory.[44] For example, each CCS project requires a capture technology engineered for a specific plant's flue gas characteristics, including temperature, pressure, CO_2 concentration, and the presence of other chemicals and impurities.[45] It will take effort to tune carbon capture to each new heterogeneous application, and progress in one setting may not translate seamlessly to another. The innovation of multiple applications will be needed to drive down project costs.

Additionally, the 45Q tax credit cannot be claimed until after the CO_2 is stored and verified under EPA guidance. In many cases, the CO_2 capturing entity is different from the organization managing the CO_2 storage and monitoring. This adds financial risks to CCS projects. Meanwhile, CCS value chain complexity creates coordination costs and development risks that are disadvantageous to most developers, relative to other clean energy projects.[46] Aligning capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements creates project uncertainty. These are crucial next steps for CCS that may be challenging to address to reach the scale of commercial projects needed by 2035 to support the emissions reduction and reliability of EPA's proposal.

The IRA directed considerable funding into the 45Q tax incentive. In addition to expanding the credit's value to \$85/t, the IRA extended the construction window for eligibility of the CCS projects for 45Q credits to January 1, 2033. However, EPA's proposal requires coal and gas generators to decide on their pathways by 2030 and 2032, respectively. Extending EPA's deadline to be aligned with the existing 45Q policy requirements could improve investor confidence concerned with the timing and uncertainty of developing and permitting CCS projects.

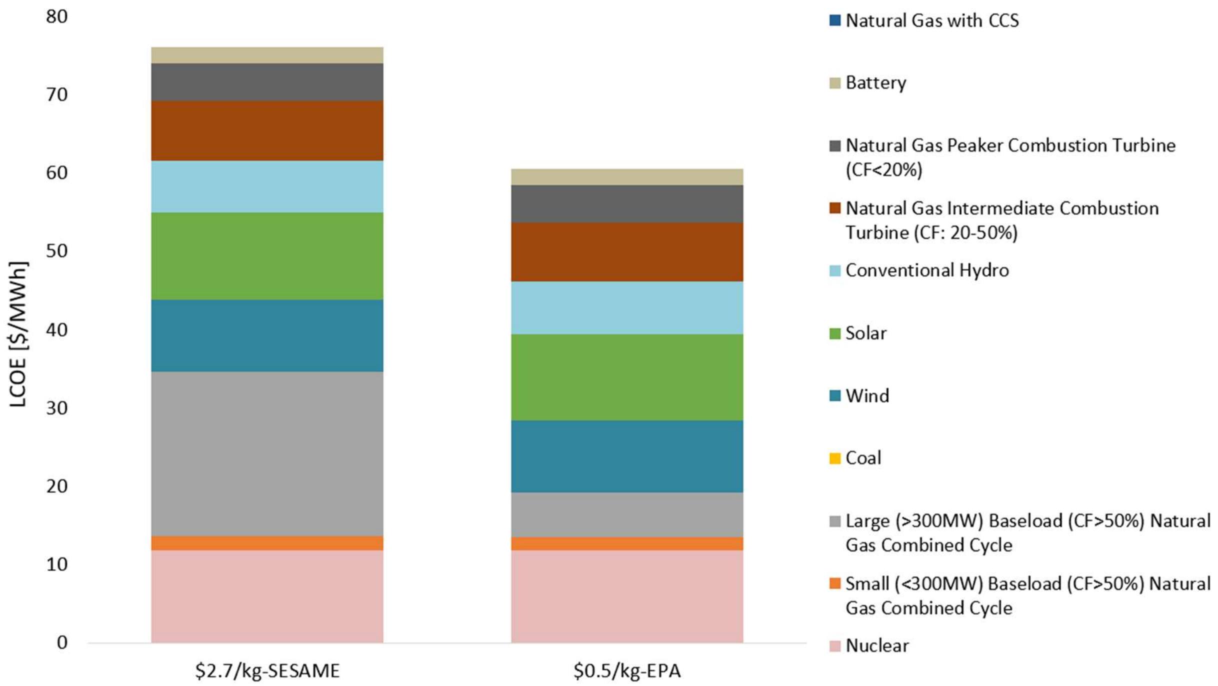
Clean Hydrogen Costs

The U.S. maintains one of the world's largest hydrogen industries, though virtually no clean hydrogen is produced or consumed there today. In 2021, the United States produced roughly 11.4 Mt of "gray" hydrogen, more than 15% of the world's total. Even though the IRA's 45V tax credit—the primary U.S. financial incentive for clean hydrogen projects—defines clean hydrogen as having an LCA of less than 4.0 kg CO_2e/kg H_2, EPA's proposed rule defines clean hydrogen as having life cycle emissions of 0.45 kg CO_2e/kg H_2. This greatly changes the type, scale, and regional diversity of eligible hydrogen production projects for making this very low-emissions product. Moreover, scaling up this low-carbon hydrogen will depend on new electrolysis capacity, new clean electricity supply, and enabling systems that do not currently exist.

EFI Foundation estimates the average U.S. cost of clean hydrogen as \$2.7/kg, including \$3/kg of 45V incentives. This is much higher than EPA's estimate of \$0.5/kg starting in 2032. The difference in LCOE of these estimates can be considerable (Figure 19). There are large cost gaps that need to be overcome to support the deployment of these projects to bolster the grid with clean firm resources.

Figure 19.

Comparing LCOE using EPA and EFI Foundation (High H2 case) clean hydrogen costs



The cost of clean hydrogen estimated in this analysis ($2.7/kg) is much higher than the value estimated by EPA ($0.5/kg), resulting in a higher levelized cost of electricity (LCOE) in the High H2 case. High clean hydrogen demand from large base load natural gas combined cycle power plants, which need to co-fire clean hydrogen at 30% and 96% volume by 2032 and 2038, respectively, contributes to this result. Source: EFI Foundation modeling analysis using SESAME tool.

EPA's cost target does align with DOE's estimate of power generators' "willingness to pay" for clean hydrogen in the $0.4-$0.5/kg range by 2030.[47] However, EPA's cost estimate may not include the total delivered cost that includes the enabling infrastructure, such as pipelines and storage. The cost of delivering and storing clean hydrogen can add roughly $2/kg to the total cost of production (Figure 20).[48]

Figure 20.

DOE's estimated delivered hydrogen costs

Blue hydrogen pathway example				
Production	***Delivery***	***Storage***	***End Use***	***Totals***
Steam methane reformation (SMR) w/CCS, **\$0.4-\$0.85/kg**	Gas compression, **\$0.1-\$0.4/kg** H_2 pipeline, **\$0.1/kg** Gas phase trucking, **\$0.7-\$1.5/kg**	Salt cavern storage, **\$0.1/kg** Compressed tank, **\$0.8/kg**	Natural gas blending, **\$0.4-\$0.5/kg**	**\$2.6-\$4.25/kg**
Green hydrogen pathway example				
Water electrolysis, **\$0.4/kg (w/PTC)**	Liquefaction, **\$2.7/kg** Liquid trucking, **\$0.2-\$0.3/kg**	Liquid storage, **\$0.2/kg**	Power generation (high-capacity firm), **\$0.4-\$0.5/kg**	**\$3.9-\$4.1/kg (w/ PTC)**
EPA estimate for "green" hydrogen (i.e., 0.45 kg CO_2e/Kg H_2)				
EPA estimate, **\$0.5-\$1/kg (w/PTC)**				**\$0.5-\$1/kg and (w/PTC)**

EPA's estimate for green hydrogen does not seem to include the costs of enabling hydrogen infrastructure to deliver and store hydrogen, such as pipelines and storage, which can add roughly \$2/kg to the final hydrogen production cost. These estimates already include the hydrogen production tax credit (PTC), also known as 45V. Source: See first figure mention in text for sources.

The need to bring down costs and scale the entire clean hydrogen value chain motivated the IIJA's \$8 billion Regional Clean Hydrogen Hubs (H2Hubs) program, aiming to "demonstrate the production, processing, delivery, storage, and end-use of clean hydrogen."[49] It likely will be another decade before the full lessons are learned from the H2Hubs program, as the execution of these demonstration projects is expected to take eight to 12 years.[50]

EPA's proposal depends on rapidly overcoming permitting challenges of enabling infrastructure

EPA's proposed rules aim to rapidly accelerate decarbonization through technology-based targets. EFI Foundation modeling shows the proposal could drive all coal generators to retire by 2035, leading to a fivefold increase in solar and a threefold increase in wind capacity by 2035 compared to today. While some of these new projects could be developed in locations to take advantage of existing infrastructure, it is likely that massive enabling infrastructure builds will be required: Hundreds of GW of new transmission, hundreds of GW of new renewables dedicated to clean hydrogen production, and major deployments of CCS infrastructure will still be needed.

EPA's RIA assumes these new resources are available and interconnected to seamlessly replace the missing energy and capacity. EPA's proposed rules should consider the permitting challenges when determining the compliance costs of its policy. These transition challenges could derail the sector's ability to implement EPA's proposal.

While the IIJA and IRA incentives support CCS and clean hydrogen, neither policy adequately addresses the permitting reform needed to develop and scale CCS and clean hydrogen. In the past year, both the White House and Congress have pushed for energy infrastructure permitting reform aligned to the pace and scale needed to realize the full economic benefits of the IRA.

In May 2022, the White House announced the Biden-Harris Permitting Action Plan, a series of administrative actions to "strengthen and accelerate Federal permitting and environmental reviews." After the passage of the IRA, U.S. Sen. Joe Manchin (D-W.Va.) proposed the Building American Energy Security Act of 2022 (BAESA), which focused specifically on permitting for energy projects. In 2023, House Republican leadership introduced H.R. 1, the Lower Energy Costs Act, which also included a major focus on energy project permitting reform.

Most CCS and clean hydrogen projects have value chain components that are separate industries with different needs (e.g., skill sets) and requirements (e.g., permits), each regulated independently with little federal coordination. CCS and clean hydrogen projects depend on new pipelines, power lines, new sources of electricity, and above- or below-ground storage, among other infrastructure. Assuming there is no financial risk of building out the system, needs across multiple sectors and many regions—each with different regulatory systems—may underestimate the compliance costs and timing of the proposed rules.

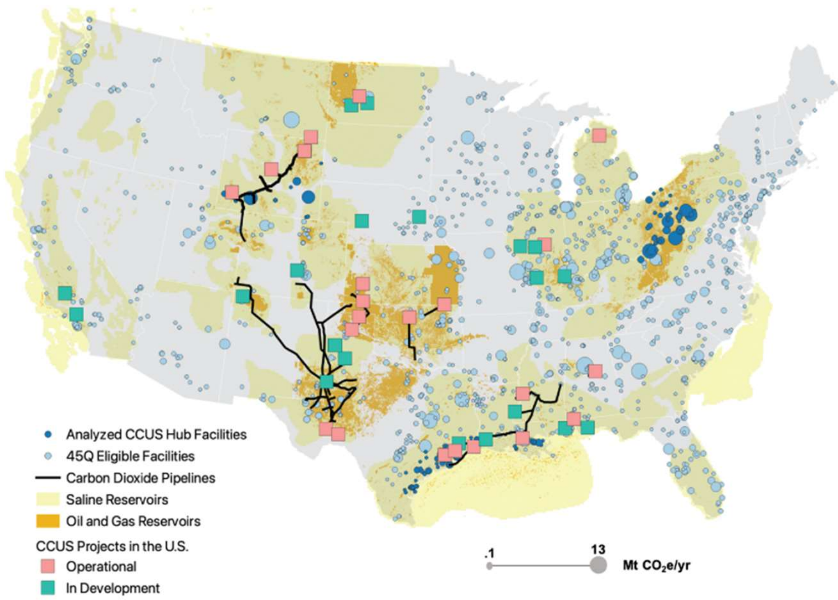
Carbon Capture and Storage Infrastructure

Carbon capture and storage (CCS) and transport systems enable a range of CO_2 abatement strategies. These systems are likely to play a vital role in reaching economywide net-zero emissions. As EPA's proposal reflects, CCS can support both increased renewable energy generation and grid reliability by enabling low-carbon firm power generation. Fuels, including hydrogen, produced with CCS have lower life cycle emissions, helping to decarbonize transportation and industrial end uses that are difficult to electrify.

The United States has abundant geologic resources for permanent long-term CO_2 storage and an existing network of CO_2 pipelines, spanning 4,500 miles and servicing mainly enhanced oil recovery projects (Figure 21).[51] There is roughly 20 MTPA of CO_2 capture capacity in the United States today—though none of it is in the power sector. There are at least nine announced CCS FEED studies on natural gas combined cycle power plants, mostly focused on improving the capture technology on a performance and cost basis.[52]

Figure 21.

Existing CCS infrastructure and 45Q-eligible facilities



Existing CCS-enabling infrastructure in the United States includes CO_2 pipelines and storage sites such as saline and oil and gas reservoirs. The map also shows the location of facilities eligible for the carbon sequestration tax credit (45Q), as well as the location of operational and under-development CCS projects. Source: See first figure mention in text for sources.

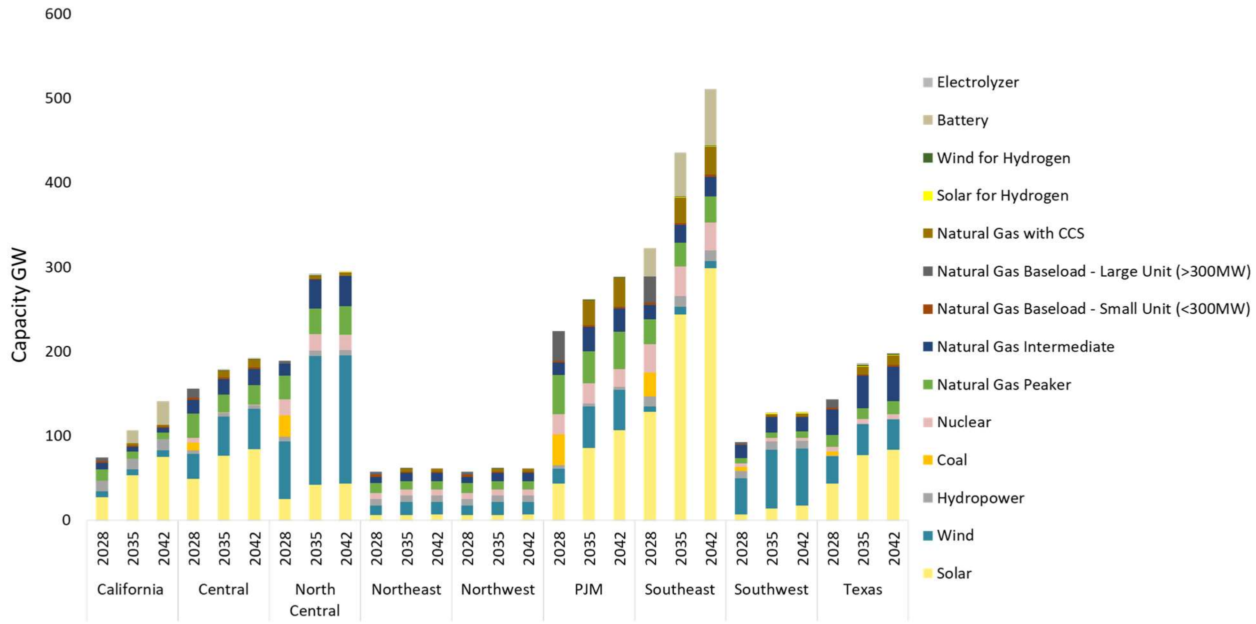
Modeling Results

In EFI Foundation's High CCS scenario, all coal is phased out by 2035, which profoundly impacts certain regions, including PJM, the Southeast, and North Central. The approach for covering that supply shortfall depends on each region's existing resources and the size and types of assets also impacted by EPA's proposal. Natural gas continues to play a role, with capacity increases in small base load, and large base load with CCS.

In this scenario, EPA's proposal requires CCS on 94 GW of gas-fired generation by 2035 and 105 GW by 2042. For context, installed capacity for all natural gas plants was 520 GW in 2022. Total renewables increase fivefold by 2042, while gas-fired capacity decreases slightly to 470 GW, aligned with EPA's estimates. Hydrogen demand is factored in according to the policy requirements, and battery storage is incorporated to help manage hourly reliability needs by region. Relatively small amounts of dedicated renewables (8 GW by 2042) are needed for clean hydrogen production in this scenario (Figure 22).

Figure 22.

Installed capacity by region in High CCS case

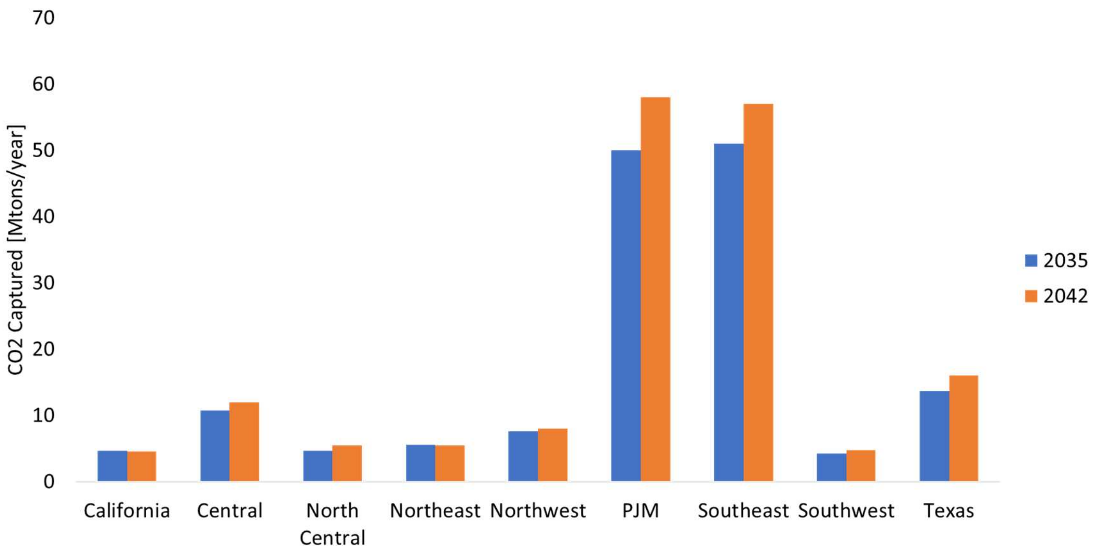


In the High CCS scenario, base load natural gas power plants must deploy CCS in 2035. The regions where most of these plants are located (e.g., PJM, Southeast, Southwest, Texas) experience an increase in installed capacity for these units. Source: EFI Foundation modeling analysis using SESAME tool.

With 90% capture rates set by EPA's proposal, there would be 150 MTPA of captured CO_2 in 2035 and roughly 170 MTPA by 2042 (Figure 23).

Figure 23.

Total CO_2 captured in High CCS scenario

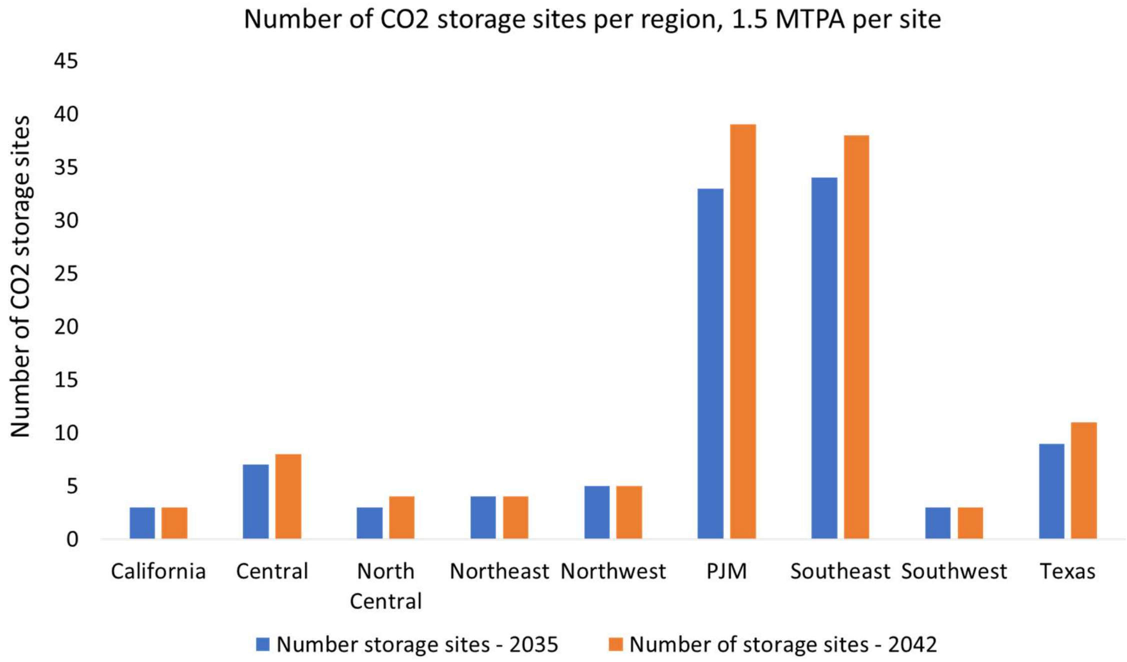


The amount of CO_2 captured in the High CCS case is higher in the regions with the most natural gas base load plants, which must adopt CCS technologies from 2035. Source: EFI Foundation modeling analysis using SESAME tool.

There are many options for building out the storage and pipeline infrastructure needed in the High CCS scenario. It is assumed that CO_2 cannot be piped between regions, recognizing some of the permitting challenges of building new energy infrastructure across state lines. Assuming each geologic storage site can handle 1.5 MTPA, the High CCS scenario results in a total of 101 sites in 2035 and 115 in 2042 (Figure 24). Increasing the capacity at each site affects the number of sites needed and the size of the pipeline infrastructure required.

Figure 24.

Number of CO_2 storage sites per region in High CCS scenario

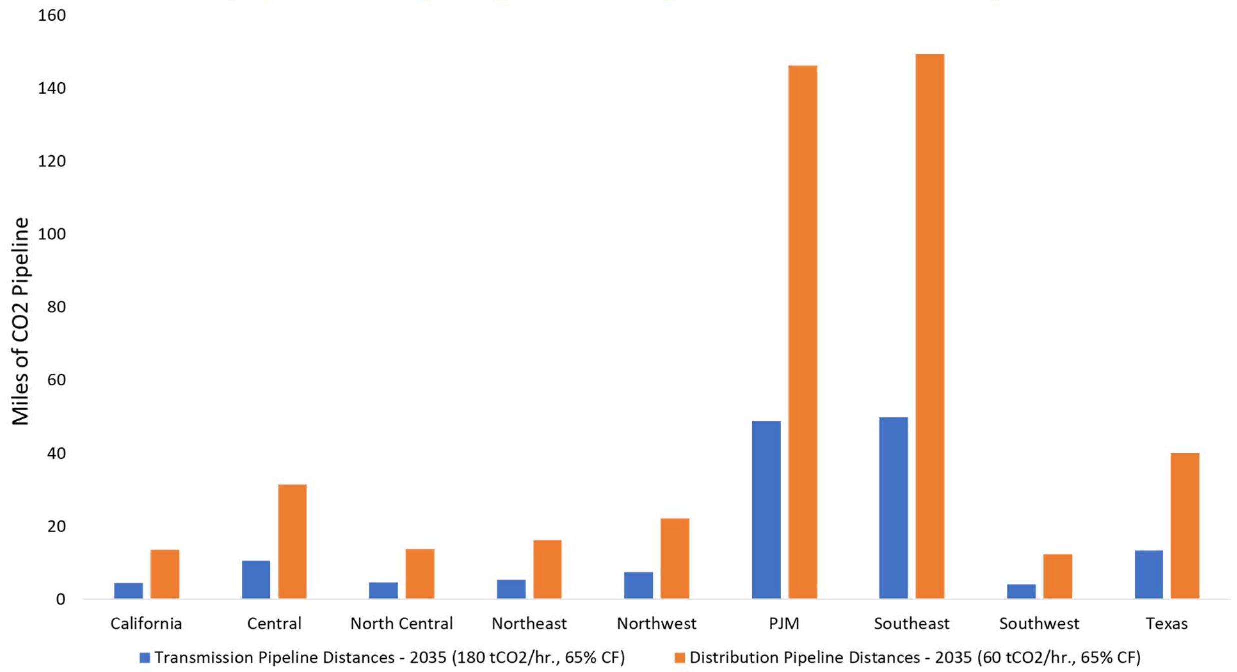


The PJM and Southeast regions, where most natural gas base load plants that adopt CCS in this scenario are located, have suitable CO_2 storage sites in saline and oil and gas reservoirs (see Figure 21). Source: EFI Foundation modeling analysis using SESAME tool.

A large network of transmission and distribution pipelines would be needed to enable the High CCS scenario, carrying CO_2 from sources to sinks. It was assumed that sufficient pipeline capacity could be built to handle the CO_2 volumes captured in each policy scenario, traveling the shortest distance from the gas unit to the center of a CO_2 storage resource, according to the National Carbon Sequestration Database and Geographic Information System (NATCARB).[53] To simplify the estimate, it is assumed that each CCS unit is supported by at least one transmission pipeline that can carry 180 metric tons of CO_2 per hour. The results show that, by 2035, roughly 150 large CO_2 transmission pipelines covering over 50,000 miles would be needed (Figure 25). Other studies suggest that the United States will need 30,000 to 66,000 miles of CO_2 pipelines by 2050 to meet net-zero targets, allowing for another two decades to sort through permitting and other issues.[54]

Figure 25.

Miles of CO_2 pipelines by region in High CCS scenario by 2035



A large deployment of CO_2 transmission and distribution pipelines would be needed to transport captured CO_2 to storage sites around the country. As expected, pipeline needs are higher in the regions with the most CCS deployment. Source: EFI Foundation modeling analysis using SESAME tool.

Permitting Challenges

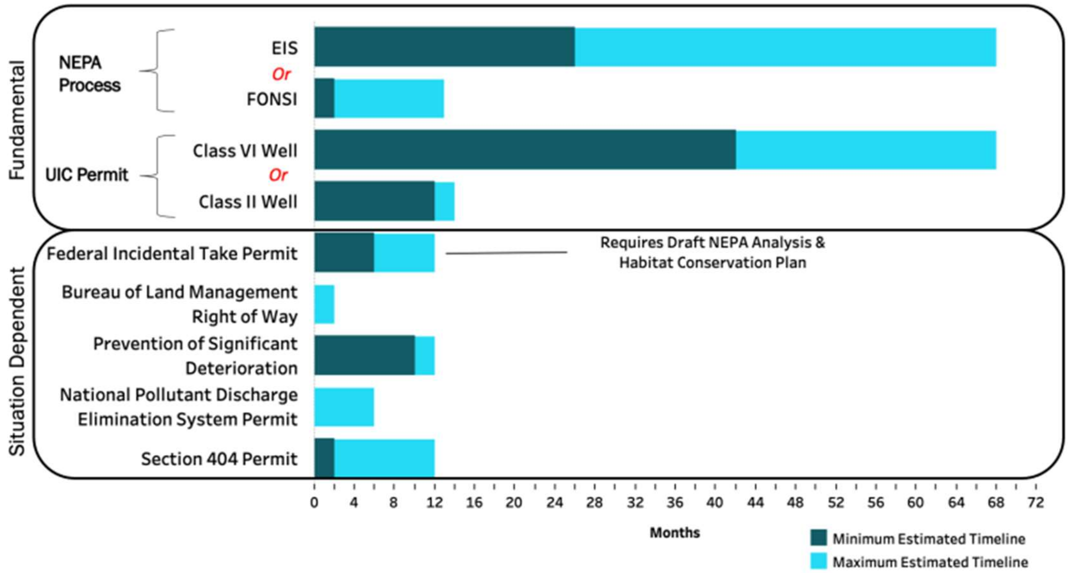
Developing and permitting enough CO_2 pipelines and geologic storage capacity to support EPA's proposal likely requires new policies and regulations that align the capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements.

Permitting CCS projects is a highly uncertain process that can take years in ideal conditions (Figure 26).[55] The CCS value chain covers multiple sectors—each with different regulatory systems with little federal coordination—creating complex permitting needs.

An average CCS project consists of CO_2 capture facilities, processing plants, pipeline transport, and permanent geologic storage. CCS value chain complexity creates coordination costs and development risks that are disadvantageous to most developers, relative to other clean energy projects.[56]

Figure 26.

Estimated range of timelines for some CO_2 infrastructure regulatory and permitting processes



The process to permit CCS projects can take several months. It starts with the National Environmental Protection Act (NEPA) process, which is required when a project may significantly affect the environment. If the assessment finds no significant environmental impacts related to the project, an Environmental Assessment and Finding of No Significant Impact (EA/FONSI) is issued. Otherwise, an Environmental Impact Statement (EIS) is required. Projects must also obtain Underground Injection Control (UIC) permits according to whether they are Class VI (projects injecting CO_2 in deep geologic reservoirs) or Class II (projects injecting CO_2 for enhanced oil recovery—EOR). A Class II permit does not apply to the scenarios analyzed in this report, which need to obtain a Class VI permit instead. In addition, depending on the situation, CCS projects must also undergo other reviews to obtain a permit. Source: See first figure mention in text for sources.

EFI Foundation's analysis shows that state agencies may not be familiar with CCS and developers may not be familiar with the myriad permits required for a complex CCS project. Also, timelines for certain permitting steps—namely the Underground Injection Control (UIC) program Class VI application and the National Environmental Policy Act (NEPA) review process—are uncertain and potentially lengthy. Because CCS projects involve at least two processes (capture and storage) and sometimes transport as well, they can cross multiple regulatory jurisdictions.

In addition to 45Q, the IRA and IIJA include provisions that support CO_2 pipeline development, including $2.1 billion for low-interest loans and grants for CO_2 transportation and DOE authority to include support for CO_2 transport FEED studies. In May 2023, DOE announced $9 million in funding for three CO_2 pipeline network FEED studies in Wyoming, Louisiana, and Texas. DOE's $8 billion Regional Clean Hydrogen Hubs program will also likely include support for CO_2 transport infrastructure at one or more hubs.

As of June 2021, only two operational Class VI wells—both part of Archer Daniel Midland's CCUS project in Decatur, Illinois—had been permitted in the United States. It took nearly six years for the project to receive its permit to inject, a critical step to bringing a CCS facility online. CCS permitting is highly variable across the country, and numerous entities are involved in the process.[57] States have primary siting authority over CO_2 pipelines and set safety standards for intrastate pipelines. For pipelines that cross state lines, the federal Pipeline and Hazardous Materials Safety Administration sets safety standards governing CO_2 pipeline construction, maintenance, and operation.[58]

Box 1

Recent challenges to building CCS infrastructure

In early September 2023, the South Dakota Public Utilities Commission struck down an application to build a 1,300-mile carbon capture pipeline system that would connect five ethanol plants retrofitted with carbon capture. The commission said the project did not meet the statutory requirements of: 1) complying with applicable laws and rules, 2) not posing a threat of serious injury to the environment nor to the social and economic conditions of affected landowners, 3) not substantially impairing the health, safety or welfare of the inhabitants, and 4) not unduly interfering with future development by municipalities. [59]

Navigating the property and subsurface ownership rights is another major challenge for CCS projects. Property law governing ownership of pore space[k] varies drastically between states. Legislatures in North Dakota, Wyoming, and Montana have clarified this issue by vesting ownership of the pore space with the surface owner. However, in many states with suitable CO_2 storage sites, ownership remains ambiguous. Ownership and leasing of pore space on federal lands also remain uncertain. The mineral reservations granted on federal lands do not clearly extend to pore space, as the pore space itself is not "severable" from the subsurface, unlike oil and gas. While this timeline may shorten as more projects apply for Class VI permits, uncertainty is a challenge.

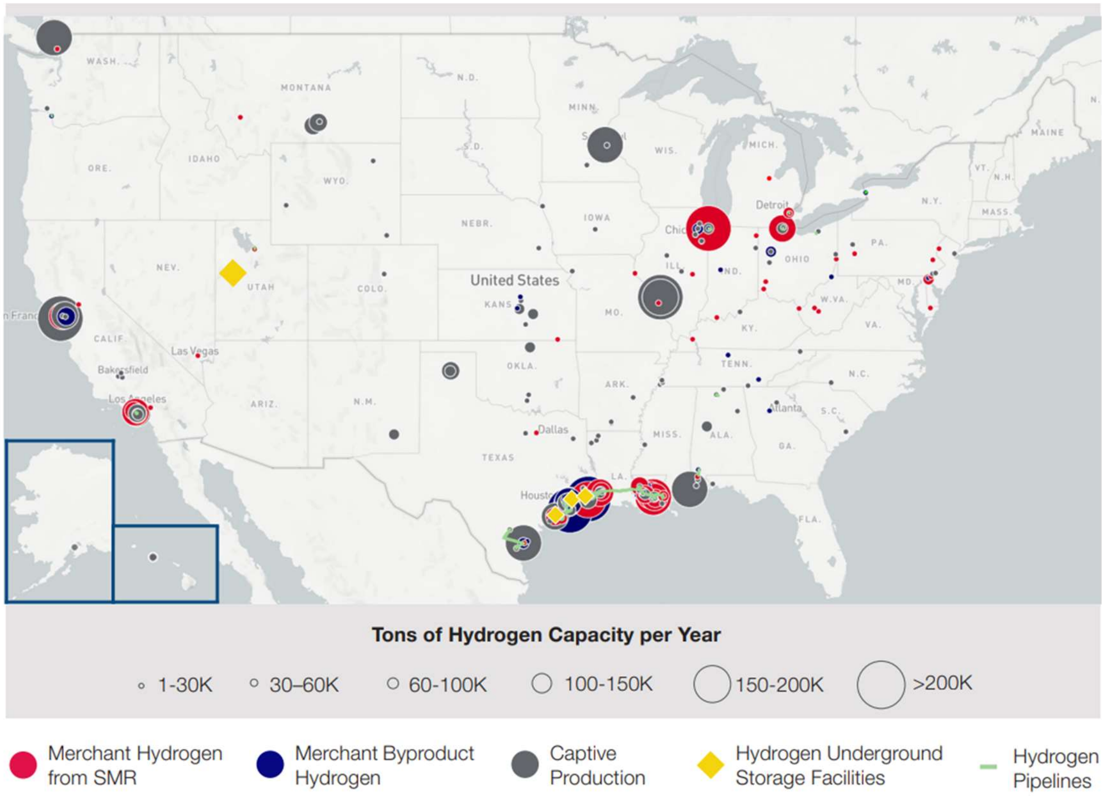
Clean Hydrogen Infrastructure

The hydrogen value chain consists of multiple production pathways, various modes of transport and storage, and dozens of potential end uses. Across each aspect of the value chain, varying levels of commercial readiness will shape near-term market development.

The United States has one of the largest hydrogen industries in the world, highly concentrated in a few regions and designed mostly to support the petrochemicals sector. No clean hydrogen is produced or consumed in the country. As of 2021, the United States had 25 hydrogen pipelines, collectively spanning 1,600 miles with four underground salt dome storage facilities in use or in development (Figure 27).[60,61]

[k] Pore space is the microscopic empty space between particles of rocks or sand.

Figure 27.
Existing U.S. hydrogen infrastructure



Existing hydrogen infrastructure in the United States is concentrated in a few regions of the country, such as the Gulf Coast, California, and the upper Midwest. Hydrogen is produced to be consumed on-site ("captive" production) or to be sold to an offtaker ("merchant" production from steam methane reformation—SMR—of natural gas or as a byproduct). Besides production infrastructure, the map also shows the location of other existing hydrogen infrastructure, such as hydrogen pipelines and underground storage facilities. Source: See first figure mention in text for sources.

As of August 2022, the EFI Foundation has tracked 374 distinct clean hydrogen project announcements that cover many aspects of the value chain.[62] Notably, since EFI Foundation began tracking projects in June 2021, the number of announced projects increased nearly sevenfold, with a major jump following the announcement of the IIJA's H2Hubs program.

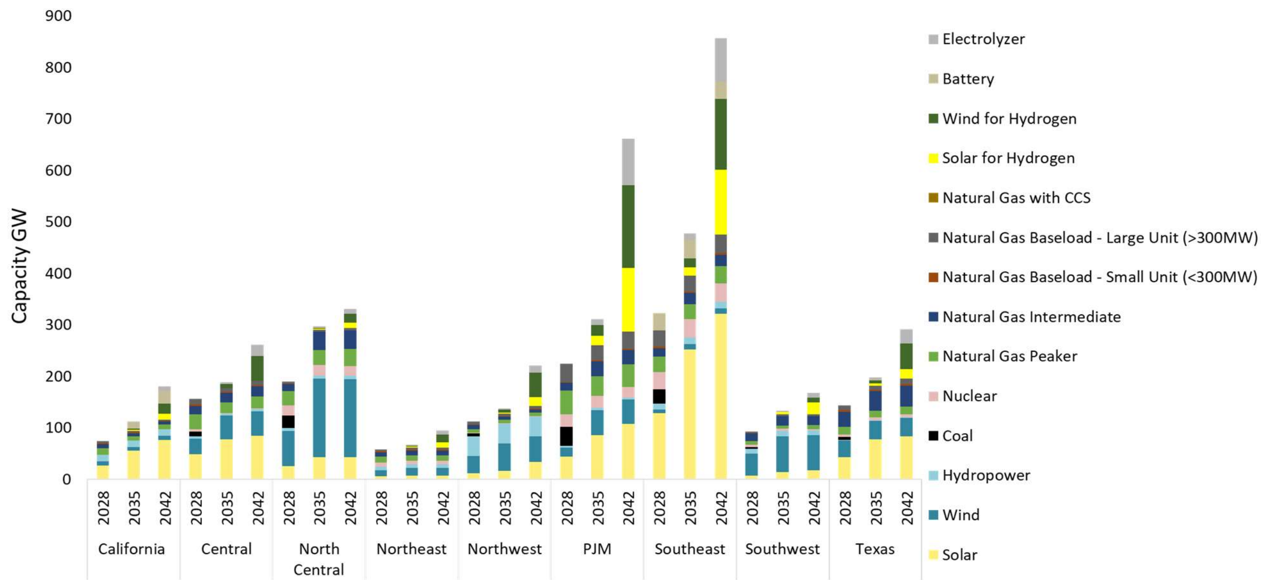
Modeling Results

In EFI Foundation's High H2 scenario, all coal is phased out by 2035, affecting certain regions more than others (Figure 28). The approach for covering that supply shortfall depends on each region's existing resources and the size and types of assets also impacted by EPA's proposal.

Solar capacity increases fivefold and wind increases threefold compared to today. Natural gas continues to play an important role, with capacity remaining flat through 2042. Major deployments of clean hydrogen infrastructure are needed as EPA's proposal requires 105 GW of hydrogen co-firing with natural gas by 2035 and 124 GW by 2042.

Figure 28.

Installed capacity by region in High H2 scenario

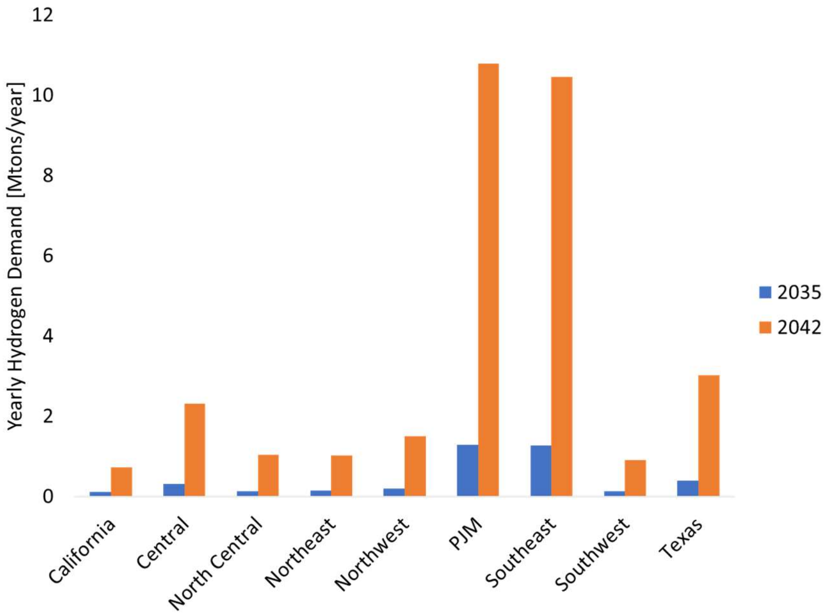


Coal power plants are phased out of the system by 2035 in the High H2 case. Renewables capacity increases to compensate, as does battery storage to provide reliability. Natural gas intermediate and base load power plants adopt clean hydrogen at a 30% rate by 2032; base load plants must ramp that value up to 96% by 2038. The observed increase in wind and solar capacity is also to produce the clean hydrogen demanded by these intermediate and base load plants. Source: EFI Foundation modeling analysis using SESAME tool.

In the High H2 scenario, U.S. hydrogen demand would grow from 4 Mt in 2032 to more than 32 Mt by 2042 (Figure 29). This massive spike in demand corresponds to EPA's proposal as all new and existing (300 MW and larger) base load units (50% CF or higher) adopted co-firing hydrogen by 30% by volume in 2032 and 96% by 2042 to comply with EPA's proposal, while all new intermediate load units employed 30% co-firing starting in 2032. As the results show, U.S. regions with a larger number of these assets demand more hydrogen than other regions.

Figure 29.

Hydrogen demand by region in High H2 case, 2035 and 2042

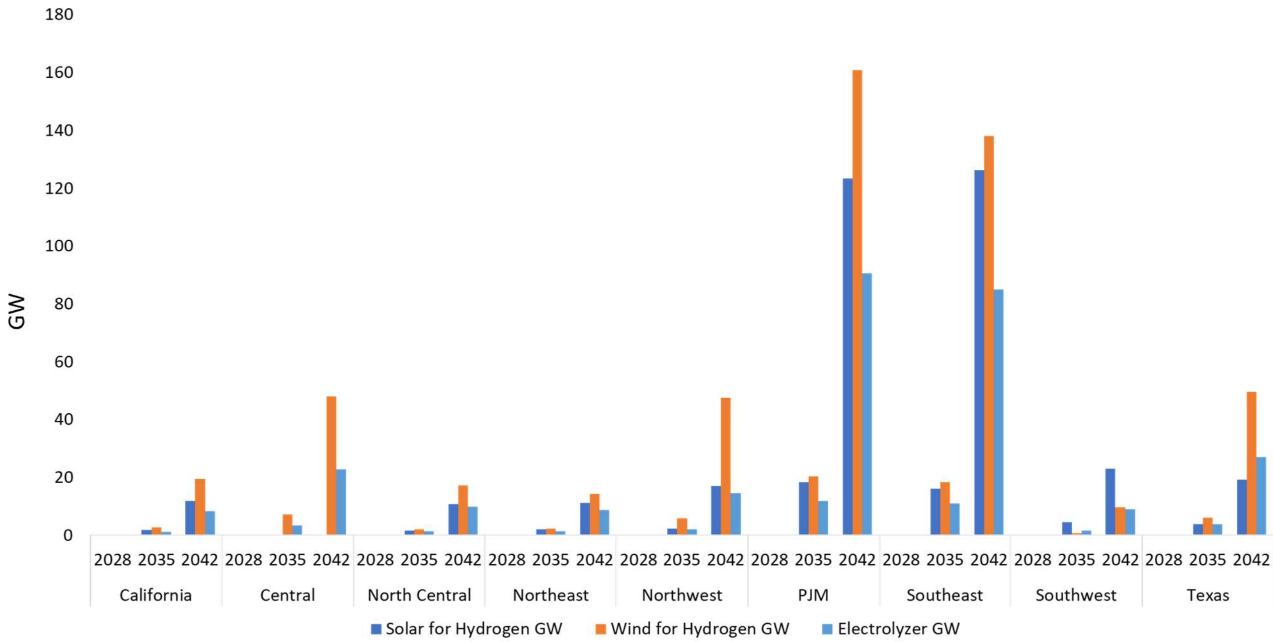


This graph shows the increase in hydrogen demand in the High H2 scenario, which occurs from intermediate and base load power plants that must blend natural gas with clean hydrogen to keep operating. Source: EFI Foundation modeling analysis using SESAME tool.

Large amounts of dedicated renewables (115 GW in 2035, 850 GW by 2042) are needed to power electrolyzers (capacities of 37 GW in 2035, 275 GW in 2042) for clean hydrogen production (Figure 30). To put this into context, there is about 230 GW of wind and solar capacity on the grid today. The electrolyzer capacity factors are a function of the renewable resources in each region.

Figure 30.

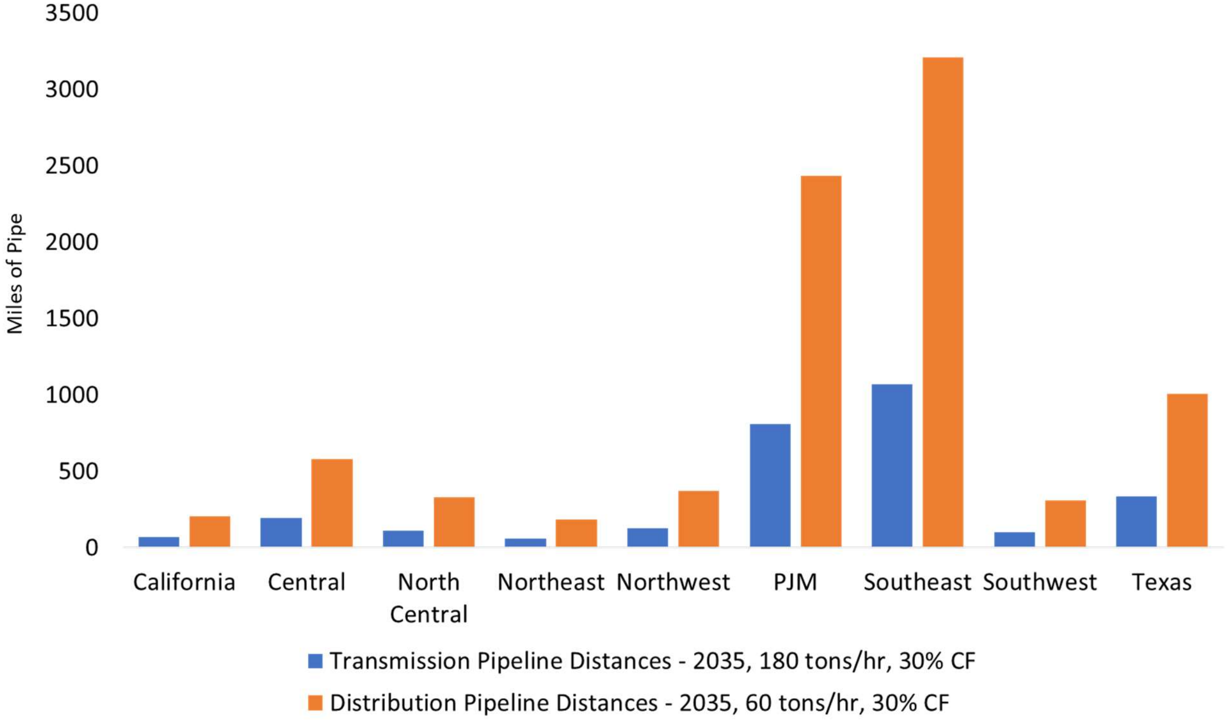
Installed capacities for hydrogen production in High H2 scenario



Electrolyzer capacity to produce clean hydrogen ramps up to fulfill demand in the PJM, Southeast, Texas, and Central regions. Both wind and solar are used in hydrogen production, depending on these resources' availability in each region. Source: EFI Foundation modeling analysis using SESAME tool.

There are many options for building out the storage and pipeline infrastructure for hydrogen. It was assumed that hydrogen cannot be piped between regions, recognizing some of the permitting challenges of building new energy infrastructure across state lines. Assuming there is access to large-scale storage (6,000 tons capacity each), such as salt domes, within each region, there would need to be roughly 30 storage sites by 2035 and more than 200 by 2042. There are four in operation or development today. Figure 31 shows the amount of pipeline needed if there was access to large-scale storage in 2035.

Figure 31.
Hydrogen pipeline miles by region in 2035, High H2 scenario



Thousands of miles of transmission and distribution pipelines need to be built nationwide in the High H2 scenario. PJM and the Southeast will experience the most hydrogen pipeline development. Source: EFI Foundation modeling analysis using SESAME tool.

For comparison, if only compressed tank storage (50 tons of capacity each) is available, the system would need more than 600 tanks by 2035 and more than 5,000 in 2042.

Box 2

Additional clean hydrogen infrastructure considerations

As the clean hydrogen industry scales, a major issue will be how early movers handle hydrogen transport and storage. According to DOE, offtakers not co-located with producers must evaluate the cost-effectiveness of hydrogen trucking (gaseous vs. liquid) for their particular use case and the extent to which newly built pipelines or retrofits will be possible.[63] Hydrogen can be distributed to power plants via trucking liquid or gaseous hydrogen, or through dedicated pipelines, or blended into existing natural gas systems. A project's solution for hydrogen delivery will depend on production schedule, distance and volume transported, and end-use requirements.

At small volumes (e.g., about 20 tons per day), hydrogen trucking can be one of the most cost-effective methods of transport. DOE estimates levelized costs of \$0.9-\$1/kg by 2030.[64] Hydrogen trucking requires relatively low CAPEX for the compressors and tube trailers, but offers very low transport capacity. This approach has a low barrier to market entry and can enable project development across the value chain. However, trucking may offer limited support for hydrogen co-firing at power plants because these facilities will depend on a highly reliable supply of relatively large volumes.

Many firms are exploring blending hydrogen into existing pipeline networks, usually in the natural gas system. This includes blending hydrogen into domestic natural gas pipelines at up to 20% by volume (2%-7% content by energy density), with a small number of demonstration projects up to 30%. The blending limits of hydrogen can be highly uncertain, driven by the age, size, materials, designs, and operations of the existing networks.[65] Moreover the costs of this approach are also highly variable.[66] While pipeline blending complements EPA's proposal, it may be difficult for gas-fired generators to rely on it for meeting the agency's proposed requirements of 30% co-firing by 2035 and 96% by 2038, without additional supplies from trucks or dedicated pipelines. Also, if the gas pipeline serves other industries, there will likely need to be additional facilities for separating and purifying hydrogen from natural gas, adding to project costs.

Dedicated hydrogen pipelines can move large volumes over long distances to achieve economies of scale (around $0.2-$0.5/kg at 600 tons per day[l]).[67] While pipelines offer the hydrogen supply reliability needed for many power generation projects, pipeline construction is time- and capital-intensive. EPA's proposal could create the stable, creditworthy offtakers needed to justify dedicated infrastructure buildout in some regions.

For generators that adopt the hydrogen co-firing strategy, they will likely need to develop new hydrogen storage to ensure their project has reliable access to hydrogen throughout the year. The costs of hydrogen storage vary greatly from $0.05/kg for geologic storage (i.e., salt domes) to up to $1/kg for compressed gas tank storage.[68] Regions outside of the Gulf Coast, where the current salt dome hydrogen storage is operating, may lack access to salt dome storage and would need to use other, costlier storage options.

Permitting Challenges

Developing and permitting new clean hydrogen projects can be a novel activity with complex regulatory jurisdictions (Figure 32).[69] Transporting hydrogen via dedicated pipelines is overseen by several federal agencies and a patchwork of federal statutes and regulations. At the local level, more entities get into the mix. The federal government regulates the economics and safety and security of hydrogen pipelines. Its role in siting and certification is focused on environmental regulations, such as the Endangered Species Act and the Clean Water Act, which may come into play depending on the location of the project.

The Surface Transportation Board, part of the U.S. Department of Transportation, regulates the rates, terms of service, and practices of interstate hydrogen pipeline carriers to ensure they are just, reasonable, and nondiscriminatory. Currently, for interstate natural gas pipelines, under Section 7(c) of the Natural Gas Act, companies must obtain a certificate of public convenience and necessity from the Federal Energy Regulatory Commission (FERC) to construct any facilities for natural gas transportation across state lines.

---

[l] Distributing 600 metric tons per day over 300 kilometers.

Figure 32.

Regulatory jurisdictions over hydrogen pipeline permitting in the Gulf Coast

	Federal	State
Fundamental	• Surface Transportation Board (STB/DOT): regulates the economic aspects of interstate hydrogen pipelines • DHS and TSA/PHMSA: regulate hydrogen pipeline safety	• Texas and state laws of any neighboring jurisdictions that the pipeline passes through: regulate pipeline siting, location, and certification • Texas Railroad Commission: pipeline compliance regulation
Situational	The following laws/agencies may be implicated: • Endangered Species Act • The National Historic Preservation Act • The Coastal Zone Management Act • The Clean Water Act • Permits from the U.S. Army Corps of Engineers • Federal Highway Administration	The following agencies may be implicated: • Texas Commission on Environmental Quality (TCEQ) • Texas Parks and Wildlife Department (TPWD)

Pipeline permitting in the Gulf Coast region must go through a matrix of federal and state regulations involving multiple agencies at both levels. Fundamental regulations are those that must be handled at the federal and state levels to properly permit a hydrogen pipeline. Situational regulations will apply based only on the particular circumstances or characteristics of individual projects, often as a result of geographic and environmental considerations. Source: See first figure mention in text for sources.

The IIJA created the H2Hubs program to address multiple challenges facing hydrogen infrastructure development. The IIJA calls for each hub to establish "a network of clean hydrogen producers, potential clean hydrogen consumers, and connective infrastructure located in close proximity." DOE set several requirements for successful applications, including demonstrating deployment of regional hydrogen infrastructure and ensuring a balance between clean hydrogen production and consumption.

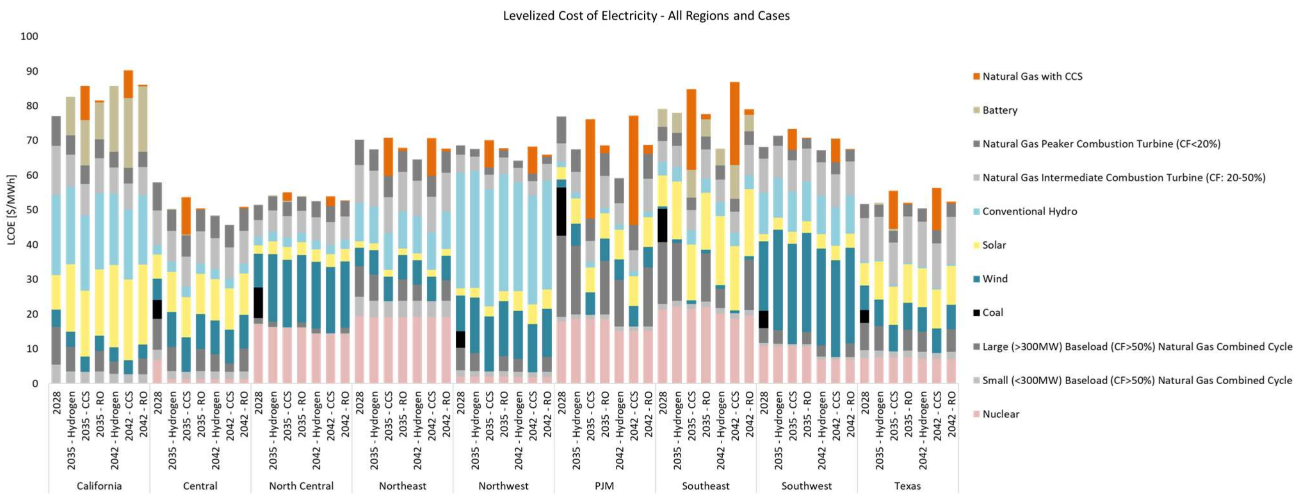
By design, regional clean hydrogen hubs will involve a broad constellation of projects and activities. Many of these will require permits and, in some cases, environmental impact statements before they can proceed. It may be difficult for hub participants and the broader industry to take advantage of the lessons learned from regional hubs as DOE expects the execution of these demonstration projects to take eight to 12 years.[70]

The proposed BSERs are not equally available across the country, leading to regional variation in system costs and net emissions benefits

BSER is a technology-based approach to reducing the electric sector's emissions. CCS and clean hydrogen are crucial decarbonization pathways that are also natural resource-dependent, and the ability to produce at scale and at low cost will differ by region. Regions with significant low-cost clean energy resources and geologic storage potential, for example, may be able to implement EPA's proposals more cost-effectively than regions with neither. EFI Foundation modeling of the LCOE across the three scenarios shows some of the regional disparities (Figure 33). Note the percent change in LCOE in some regions can be as high as 20% or as low as 15% in meeting the EPA proposal's requirements.

Figure 33.

Comparing LCOE [$/MWh] by region in High CCS, High H2, and High RO scenarios



This graph shows the contribution of each technology to electricity price, measured by the levelized cost of electricity (LCOE). As expected, the LCOE varies by scenario and region of the country according to the technologies that need to be deployed in each case studied and with the availability of local enabling infrastructure and resources. Source: EFI Foundation modeling analysis using SESAME tool.

EPA and other federal agencies can help mitigate some of the permitting uncertainty through robust federal-state engagement via the State Plans process, allowing states to propose their own optimal systems of emissions reduction that achieve the necessary environmental performance outlined by EPA's proposal. To further investigate the systemwide impacts of EPA's proposal, regional case studies were developed, supported by detailed modeling of the state's or region's energy system. Models were developed for the Carolinas, Michigan, and Pennsylvania because these states are in regions seemingly most impacted by the policy. Below are the results of the regional models and research to understand the executability and infrastructure requirements of EPA's proposal.

The Carolinas

Summary: EPA's proposal would have a significant impact on the energy systems of North Carolina and South Carolina. The region maintains one of the largest shares of large coal- and gas-fired generation that would be covered by the policy. While the Carolinas have substantial clean energy resources and policy commitments to support electricity decarbonization, the region would likely rely on the hydrogen co-firing and reduced operations options to comply with EPA's proposal, as there are limited resources for geologic storage for CCS. In the High H2 scenario, the Carolinas would demand one of the largest shares of clean hydrogen in the country. Without access to low-cost hydrogen storage (e.g., salt dome formations), the region may also have some of the highest CAPEX requirements.

Regional Modeling of EPA's Proposal

The Carolinas' economic profile and resource base are important considerations when analyzing options for compliance with EPA's proposed rules for fossil power plants. The region has abundant clean energy resources, ambitious decarbonization policies (including for the power sector), and a large industrial base to support the transition.

North Carolina plans to cut electricity emissions 70% by 2030 and reach carbon neutrality by midcentury.[71] It also has a statewide climate action plan, an interagency council on climate change, and a climate risk assessment and resilience plan.[72] Both North and South Carolina are among the top producers of nuclear electricity in the country. Solar generation also plays a major role in the region; North Carolina has one of the largest installed solar capacities in the United States. The region has one of the largest manufacturing sectors in the country, including motor vehicle assembly, chemicals, and food and beverage, among others.

To model EPA's proposal on the region, a similar approach was used for the nine EIA regions and the results for North and South Carolina were separated out Using the Annual Energy Outlook 2023 Reference Case as a baseline, modeling was done for the two states to ensure compliance with EPA's proposal while maintaining electric reliability in 2028, 2035, and 2042. Because the Carolinas have little to no access to geologic storage resources, according to the NATCARB database, it was assumed that the region would depend on hydrogen co-firing and/or reduced operations pathways to comply with EPA's proposal in 2038, 2035, and 2042.

In the two scenarios, EPA's proposal would likely drive all coal-fired generation off the system by 2035. This is aligned with existing strategies in the region.[73] Backfilling the lost generation in 2035 and 2042 will require a considerable increase in a mix of new resources. The modeling results show a need for nearly 70 GW of non-hydro renewables by 2035 and 100 GW by 2042. In the High H2 scenario, the Carolinas will need an additional 5 GW of wind and solar generation and 1.8 GW of new electrolysis to meet regional hydrogen demand by 2035. By 2042, nearly 80 GW of additional solar is needed and roughly 15 GW of new electrolysis. Hydro stays roughly flat, while new nuclear capacity increases only slightly (up by 0.3 GW). Gas-fired capacity will also increase, as 1.5 GW of new peaker capacity comes on line that is not subject to BSER requirements, and roughly 4 GW of intermediate load units are needed.

The High H2 case shows there will be 10.5 MTPA of hydrogen demand in the Southeast region in 2042, with nearly 10% of that demand in the Carolinas. The infrastructure requirements vary greatly, depending on the system configuration (e.g., a highly decentralized system or a hub). Each possible outcome has its own costs and feasibility.

Estimated annual CAPEX for the region is nearly $5.5 billion in 2035 and $22 billion in 2042. Solar costs are between $1.4 billion and $2.3 billion per year through 2042. Building the enabling hydrogen infrastructure represents the highest system costs after 2035. By 2042, hydrogen infrastructure costs include $7.4 billion for dedicated solar for hydrogen production, $3.7 billion for electrolyzers, and $1 billion for hydrogen storage.

It is assumed that only new wind and solar are used for hydrogen production, aligned with EPA's proposal of hydrogen LCA at 0.45 kg CO_2e/kg H_2. Because of the challenges of building new onshore wind in the region—in part because of the location of the resource and challenges navigating the Blue Ridge Mountains—solar accounts for most of the new renewable builds.

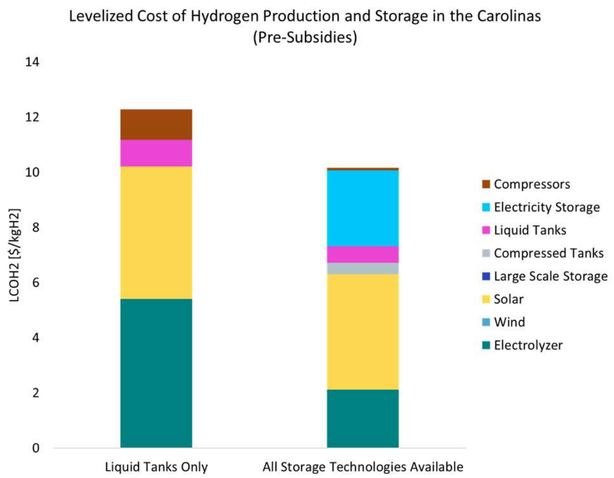
Because the region lacks access to low-cost, large-scale hydrogen storage (e.g., salt domes), the modeling presents alternative technology scenarios for storage. In one example, the Carolinas rely only on liquid tank storage, which requires large electrolyzer deployment by 2042 and a measurable cost for the compression to convert hydrogen to a liquid. The average electrolyzer CF in this example is around 24% and the levelized costs of hydrogen are around $12/kg (pre-subsidy) (Figure 35).

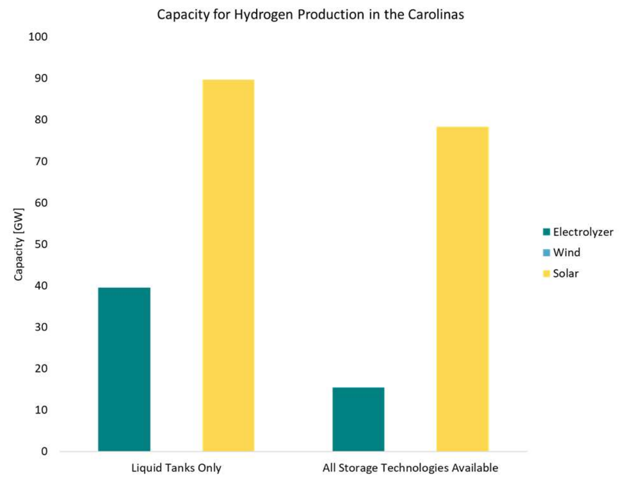
Alternatively, the Carolinas could employ multiple storage technologies, including liquid and compressed tank storage, resulting in a lower cost of delivered hydrogen, around $10/kg by 2042. This system includes large-scale (25 GW) battery storage, which increases the capacity factor of the electrolyzers, lowering the cost of delivered hydrogen. The average electrolyzer CF is 63% in this example.

In either configuration, these renewables-only hydrogen production systems can claim the full 45V tax credit subsidy ($3/kg), lowering the levelized costs to $9/kg and $7/kg in 2042, respectively, for liquid tank storage or multiple storage technologies, though much higher than EPA's assumed cost of $0.5/kg (Figure 34).

Figure 34.

High H2 case for the Carolinas, delivered hydrogen costs and system requirements in 2042



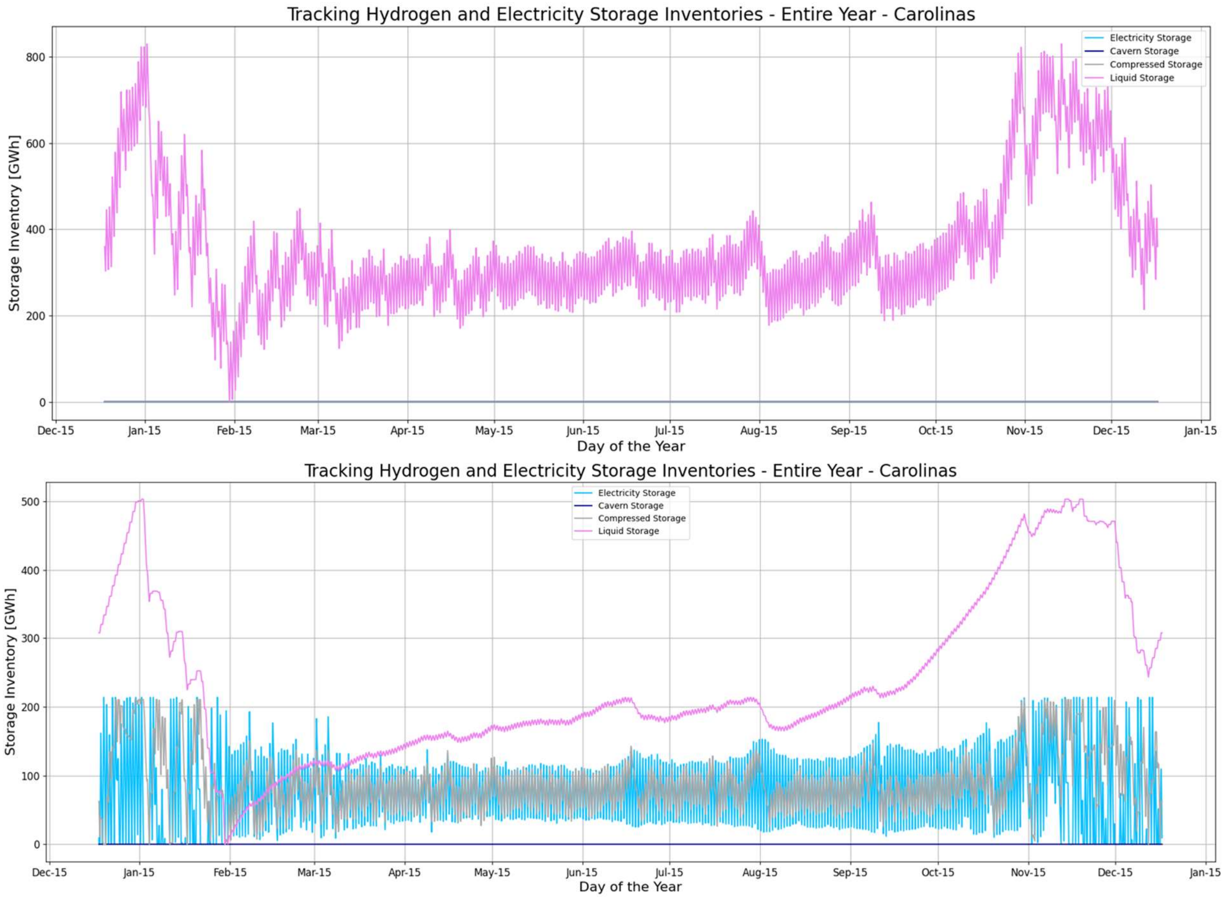


Because the Carolinas lack access to low-cost, large-scale hydrogen storage (e.g., salt domes), liquid tanks or a mix of liquid and compressed tanks ("all storage") are available for storage. The latter option results in a lower levelized cost of hydrogen (LCOH, left) because of battery storage, which increases the capacity factor of electrolyzers, lowering the cost of delivered hydrogen. The right side of the graph shows the electrolyzer and renewable capacity needed to produce clean hydrogen. Wind power does not contribute to clean hydrogen production in the Carolinas. Source: EFI Foundation modeling analysis using SESAME tool.

SESAME modeling accounts for hourly changes in supply and demand since the generators using hydrogen need highly reliable supplies throughout the year. Figure 35 shows how the two hydrogen storage examples operate throughout the year to ensure hydrogen demand is met in 2042. In both examples, renewables-heavy systems need to draw on more storage in the winter months, requiring large storage builds in the late fall.

Figure 35.

Daily and seasonal hydrogen storage flows



Hydrogen storage needs vary according to whether liquid or both liquid and compressed hydrogen storage are in place. In both examples, renewables-heavy systems need to draw on more storage in the winter months, requiring large storage builds in the late fall. Source: EFI Foundation modeling analysis using SESAME tool.

For comparison, in the High RO case for the Carolinas, natural gas capacity remains roughly flat, while gas-fired generation from intermediate load units increases by more than 20% to help cover the shortfall from the large units that reduced operations below 50% CF to lower their policy compliance costs. The costs of the hydrogen are much higher on a levelized basis than in the High H2 case. Delivered hydrogen costs (unsubsidized) are around \$11/kg in 2035 and \$8/kg in 2042.

Michigan

Summary: EPA's proposal would encourage Michigan to close its remaining coal facilities. The region maintains one of the largest manufacturing sectors and a large labor force to drive implementation. While Michigan has the resources and capabilities to support CCS and clean hydrogen, the state is prioritizing its hydrogen activities and ambitions. The modeling focuses on the High H2 scenario.

Regional Modeling of EPA's Proposal

Michigan has one of the largest manufacturing-based economies in the country, employing the largest share of workers in the motor vehicles and parts manufacturing sectors. Other core economic sectors include fabricated metal products, chemicals, food and beverage products, and plastics. Michigan also has a notable mining sector, focused primarily on non-fuel mineral products such as quarried limestone, iron ore, stone, sand and gravel, lime, copper, and cobalt.[74],

Michigan set targets to reduce economywide emissions 28% by 2025 and 52% by 2030 and to achieve carbon neutrality by 2050.[75] The state also finalized a Healthy Climate Plan in 2022 outlining the strategy to reduce emissions in different sectors through midcentury.[76] Michigan has the Council on Climate Solutions, a nongovernmental advisory body to facilitate interagency climate collaboration, and the Michigan Saves green bank.[77] In 2016, Michigan set a Renewable Portfolio Standards (RPS) target of 15% by 2021 and 35% by 2025.[78] Michigan is also ranked 11th in the nation for its grid modernization plan and efforts to date.[79]

To model EPA's proposal on the region, a similar approach was used for the nine EIA regions, and the results in Michigan were separated out. Using the *Annual Energy Outlook 2023 Reference Case* as a baseline, modeling was done for Michigan to ensure compliance with EPA's proposal while maintaining electric reliability in 2028, 2035, and 2042. Michigan has clean hydrogen initiatives underway across many sectors, including electricity.[80] It was assumed in the modeling that the state would depend on hydrogen co-firing to comply with EPA's proposal in 2038, 2035, and 2042.

In this scenario, EPA's proposal would likely drive 6 GW of coal-fired generation off the system by 2035. This is aligned with the governor's current plans.[81] Backfilling the lost generation will require a hefty increase in a mix of new resources. The modeling results show a need for nearly 30 GW of non-hydro renewables by 2035. In the High H2 scenario, Michigan will need an additional 1.8 GW of wind and solar generation and 0.6 GW of new electrolysis to meet regional hydrogen demand by 2035. By 2042, nearly 14 GW of additional wind and solar is needed and roughly 4.7 GW of new electrolysis. Hydro and nuclear stay roughly flat, while 2.5 GW of new intermediate load capacity comes on line.

The High H2 case shows there will be 10.8 MTPA of hydrogen demand in the PJM region in 2042, with nearly 5% of that demand in Michigan. The infrastructure requirements vary greatly, depending on the system configuration (e.g., a highly decentralized system or a hub). Each possible outcome has its own costs and feasibility.

Estimated annual CAPEX for the region is nearly $1.17 billion in 2035 and $4.15 billion in 2042. Solar costs are $0.25 billion per year through 2042. Building the enabling hydrogen infrastructure represents the highest system costs after 2035. By 2042, hydrogen infrastructure costs include $0.25 billion for dedicated solar and $1.6 billion for dedicated wind for hydrogen production, $1.1 billion for electrolyzers, and $0.3 billion for hydrogen storage.

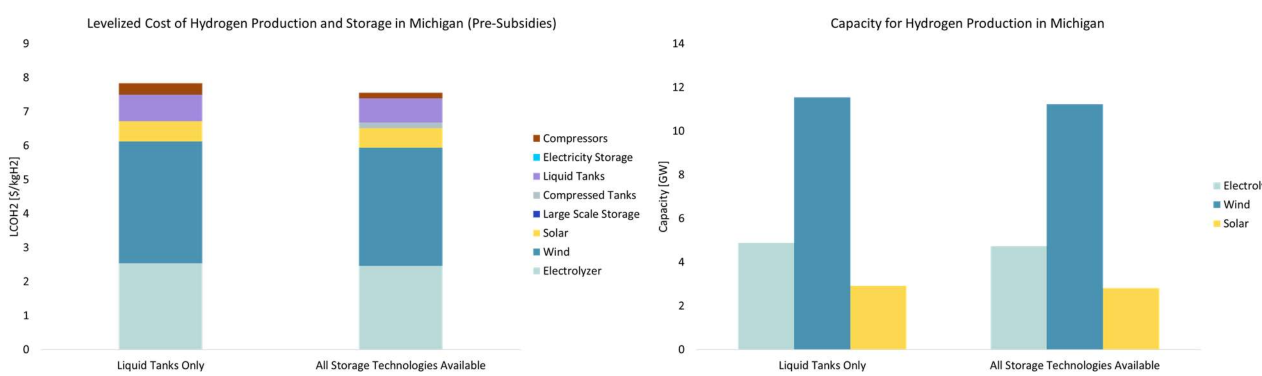
It is assumed that only new wind and solar are used for hydrogen production, aligned with EPA's proposal of hydrogen LCA at 0.45 kg CO_2e/kg H_2. Because the amount of low-cost, large-scale hydrogen storage (e.g., salt domes) is uncertain, the modeling presents alternative technology scenarios for storage. In one example, Michigan relies only on liquid tank storage, which requires large electrolyzer deployment by 2042 and a measurable cost for the compression to convert hydrogen to a liquid. The average electrolyzer CF in this example is around 52% and the levelized costs of hydrogen costs are around $8/kg (pre-subsidy) (Figure 36).

Alternatively, Michigan could employ multiple storage technologies, including liquid and compressed tank storage, resulting in a slightly lower cost of delivered hydrogen, around $7.5/kg by 2042. This system includes 2.5 GW of battery storage, which increases the CF of the electrolyzers, lowering the cost of delivered hydrogen. The average electrolyzer CF is 54% in this example.

In either configuration, these renewables-only hydrogen production systems can claim the full 45V tax credit subsidy ($3/kg), lowering the levelized costs to $5/kg and $4.5/kg in 2042, respectively, though much higher than EPA's assumed cost of $0.5/kg.

Figure 36.

High H2 case for Michigan, delivered hydrogen costs and system requirements in 2042



Large-scale hydrogen storage (e.g., salt domes) is uncertain in Michigan, which, in turn, has the option to store clean hydrogen in liquid or both liquid and compressed storage tanks. The second option results in a lower LCOH because *battery storage increases the capacity factor of electrolyzers. The graph on the right details the renewable resources (wind and solar) and electrolyzer capacities to produce clean hydrogen in Michigan. Source: EFI Foundation modeling analysis using SESAME tool.*

Pennsylvania

Summary: EPA's proposal could have a significant impact on Pennsylvania's energy system, likely driving the closure of the state's remaining coal generation and prompting considerable uptake of clean hydrogen or possibly CCS. The region maintains one of the largest manufacturing sectors and a large labor force to drive implementation. While Pennsylvania has the resources and capabilities to support CCS and clean hydrogen, the state is prioritizing its hydrogen activities and ambitions. The modeling focuses on the High H2 scenario.

Regional Modeling of EPA's Proposal

Pennsylvania has one of the largest state economies in the country.[82] About 20% of the state's GDP comes from activity in the finance, insurance, real estate, rental, and leasing sectors. The largest energy-intensive industries contributing to Pennsylvania's GDP include natural gas and oil extraction and mining, metals and machinery manufacturing, chemical products, and agriculture and food processing.[83] The state functions as one of the primary suppliers of natural gas, coal, and refined petroleum products to the East Coast. Pennsylvania is the third-largest electricity producer in the United States and the largest producer in the PJM Regional Transmission Organization.

Pennsylvania has set targets to reduce greenhouse gas emissions economywide 26% by 2025 and 80% by 2050.[84] This mandate was set in 2019, and the state released its Climate Action Plan in 2021 to outline pathways to achieve these targets.[85] The state also has a Climate Change Advisory Committee, a non-governmental advisory body to facilitate interagency climate bureaucracy collaboration.

In 2004, Pennsylvania passed an RPS target of 18% by 2021 and currently ranks 17th in the nation for its grid modernization efforts.[86,87] Pennsylvania is also a member of the Regional Greenhouse Gas Initiative (RGGI), a carbon pollution pricing mechanism adopted by a dozen states in the Northeast United States.[88]

To model EPA's proposal on Pennsylvania, a similar approach was used for the nine EIA regions, and the results for Pennsylvania were separated out. Note that in EIA's subregions, Pennsylvania includes parts of New Jersey and Delaware. Using the *Annual Energy Outlook 2023 Reference Case* as a baseline, modeling was done for Pennsylvania to ensure compliance with EPA's proposal while maintaining electric reliability in 2028, 2035, and 2042. It was assumed in the modeling that the state would depend on hydrogen co-firing to comply with EPA's proposal in 2038, 2035, and 2042.

In this scenario, EPA's proposal would likely drive 11.5 GW of coal-fired generation off the system by 2035, reflecting recent trends in the state.[89] Backfilling the lost generation will require a major increase in a mix of new resources. The modeling results show a need for nearly 33 GW of non-hydro renewables by 2035. In the High H2 scenario, Pennsylvania will need an additional 16.5 GW of wind and solar generation and 5 GW of new electrolysis to meet regional hydrogen demand by 2035. By 2042, nearly 145 GW of additional wind and solar is needed and roughly 45 GW of new electrolysis. Hydro and nuclear stay roughly flat, while 1.5 GW of new intermediate load capacity comes on line.

The High H2 case shows there will be 10.8 MTPA of hydrogen demand in the PJM region in 2042, with nearly 10% of that demand in Pennsylvania. The infrastructure requirements vary widely, depending on the system configuration (e.g., a highly decentralized system or a hub). Each possible outcome has its own costs and feasibility.

Estimated annual CAPEX for the region is nearly $5 billion in 2035 and $34 billion in 2042. Solar costs are $0.5 billion per year through 2042. Building the enabling hydrogen infrastructure represents the highest system costs after 2035. By 2042, hydrogen infrastructure costs include $6 billion for dedicated solar and $11.4 billion for dedicated wind for hydrogen production, $11 billion for electrolyzers, and $3 billion for hydrogen storage.

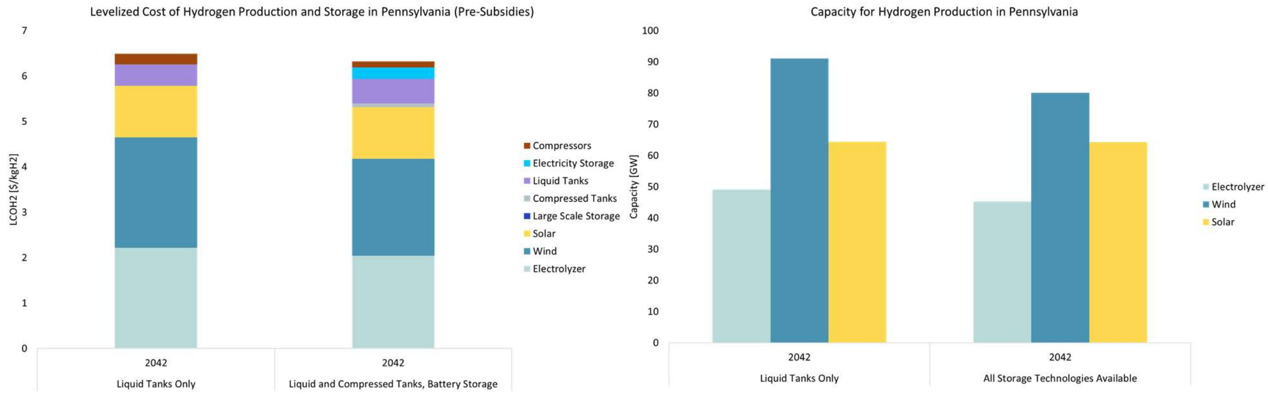
It is assumed that only new wind and solar are used for hydrogen production, aligned with EPA’s proposal of hydrogen LCA at 0.45 kg CO_2e/kg H_2. Because the amount of low-cost, large-scale hydrogen storage (e.g., salt domes) is uncertain, the modeling presents alternative technology scenarios for storage. In one example, Pennsylvania relies only on liquid tank storage, which requires large electrolyzer deployment by 2042 and a measurable cost for the compression to convert hydrogen to a liquid. The average electrolyzer CF in this example is around 60%, and the levelized costs of hydrogen costs are around $6.5/kg (pre-subsidy) (Figure 37).

Alternatively, Pennsylvania could employ multiple storage technologies, including liquid and compressed tank storage, resulting in a slightly lower cost of delivered hydrogen, around $6.3/kg by 2042. This system includes 2.5 GW of battery storage, which increases the CF of the electrolyzers, lowering the cost of delivered hydrogen. The average electrolyzer CF is 65% in this example.

In either configuration, these renewables-only hydrogen production systems can claim the full 45V tax credit subsidy ($3/kg), lowering the levelized costs to $3.5/kg and $3.5/kg 2042, respectively, though much higher than EPA’s assumed cost of $0.5/kg.

Figure 37.

High H2 case for Pennsylvania, delivered hydrogen costs and system requirements in 2042



Large-scale clean hydrogen storage is also an uncertainty in Pennsylvania. As such, liquid and both liquid and compressed tank hydrogen storage are options to store clean hydrogen in the state. As in the previous examples, the combination of storage techniques results in lower LCOH. The graph on the right displays electrolyzer and renewables' capacity to produce clean hydrogen in Pennsylvania. Source: EFI Foundation modeling analysis using SESAME tool.

References

[1] Smart Electric Power Alliance (SEPA), "Utility Carbon-Reduction Tracker™," SEPA, accessed October 2, 2023, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.

[2] Megan Ceronsky and Tomás Carbonell, *Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants*, Environmental Defense Fund, October 2013, https://www.edf.org/sites/default/files/section-111-d-of-the-clean-air-act_the-legal-foundation-for-strong-flexible-cost-effective-carbon-pollution-standards-for-existing-power-plants.pdf.

[3] U.S. Environmental Protection Agency (EPA), *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, EPA-452/R-23-006, 2023, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf, p. 4-15

[4] U.S. Department of Energy (DOE), *U.S. National Clean Hydrogen Strategy and Roadmap*, June 2023, https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.

[5] U.S. Department of Energy (DOE), *Pathways to Commercial Liftoff: Carbon Management*, April 2023, https://liftoff.energy.gov/wp-content/uploads/2023/06/20230424-Liftoff-Carbon-Management-vPUB_update3.pdf.

[6] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2023*, accessed October 2, 2023, https://www.eia.gov/outlooks/aeo/index.php.

[7] U.S. Environmental Protection Agency (EPA), *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, EPA-452/R-23-006, 2023, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf, p. 3-27.

[8] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2023*, accessed October 2, 2023, https://www.eia.gov/outlooks/aeo/index.php.

[9] U.S. Energy Information Administration (EIA). "More than Half of New U.S. Electric-Generating Capacity in 2023 Will Be Solar." Today In Energy, February 6, 2023. https://www.eia.gov/todayinenergy/detail.php?id=55419.

[10] EFI Foundation, *Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/20230212-CCS-Final_Full-copy.pdf.

[11] EFI Foundation, *The U.S. Hydrogen Demand Action Plan*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/EFI-Hydrogen-Hubs-FINAL-2-1.pdf.

[12] U.S. Department of Energy (DOE), Fossil Energy and Carbon Management Office (FECM). "Creating a Community and Stakeholder Engagement Plan," August 2022. https://www.energy.gov/sites/default/files/2022-08/Creating%20a%20Community%20and%20Stakeholder%20Engagement%20Plan_8.2.22.pdf.

[13] U.S. Department of Energy (DOE), Office of Clean Energy Demonstrations (OCED), Funding Opportunity Announcement No.: DE-FOA-0002779, "Bipartisan Infrastructure Law: Additional Clean Hydrogen Programs (Section 40314): Regional Clean Hydrogen Hubs," September 1, 2023, https://oced-exchange.energy.gov/Default.aspx#FoaId4e674498-618c-4f1a-9013-1a1ce56e5bd3, p. 19.

[14] Energy Futures Initiative. "CO2-Secure: A National Program to Deploy Carbon Removal at Gigaton Scale," December 7, 2022. https://energyfuturesinitiative.org/reports/co2-secure-a-national-program-to-deploy-carbon-removal-at-gigaton-scale/.

[15] U.S. Energy Information Administration (EIA), "Frequently Asked Questions (FAQs): How Much of U.S. Carbon Dioxide Emissions are Associated with Electricity Generation?," accessed October 19, 2023, https://www.eia.gov/tools/faqs/faq.php?id=77&t=11

[16] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2023*, accessed October 2, 2023, https://www.eia.gov/outlooks/aeo/index.php.

[17] Smart Electric Power Alliance (SEPA), "Utility Carbon-Reduction Tracker™," SEPA, accessed October 2, 2023, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.

[18] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2023*, accessed October 2, 2023, https://www.eia.gov/outlooks/aeo/index.php.

[19] U.S. Department of Energy (DOE), Office of Energy Efficiency & Renewable Energy (EERE), "NREL Study Identifies the Opportunities and Challenges of Achieving the U.S. Transformational Goal of 100% Clean Electricity by 2035," August 30, 2022, https://www.energy.gov/eere/articles/nrel-study-identifies-opportunities-and-challenges-achieving-us-transformational-goal.

[20] U.S. Department of Energy (DOE), Office of Energy Efficiency & Renewable Energy (EERE), "NREL Study Identifies the Opportunities and Challenges of Achieving the U.S. Transformational Goal of 100% Clean Electricity by 2035," August 30, 2022, https://www.energy.gov/eere/articles/nrel-study-identifies-opportunities-and-challenges-achieving-us-transformational-goal.

[21] U.S. Energy Information Administration (EIA), "Nearly a Quarter of the Operating U.S. Coal-Fired Fleet Scheduled to Retire by 2029," Today in Energy, accessed October 18, 2023, https://www.eia.gov/todayinenergy/detail.php?id=54559.

[22] U.S. Environmental Protection Agency (EPA), OAR, "Summary of the Clean Air Act," Overviews and Factsheets, accessed October 2, 2023, https://www.epa.gov/laws-regulations/summary-clean-air-act.

[23] U.S. Environmental Protection Agency (EPA), "Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units," May 2023, https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf, p. 4.

[24] U.S. Environmental Protection Agency (EPA), "Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule," accessed October 2, 2023, https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf, p. 3.

[25] U.S. Environmental Protection Agency (EPA), *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, EPA-452/R-23-006, 2023, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

[26] U.S. Environmental Protection Agency (EPA), "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Webinar for Communities with Environmental Justice Concerns and Members of Tribal Nations," June 2023, https://www.epa.gov/system/files/documents/2023-06/111%20Power%20Plants%20Stakeholder%20Presentation_Webinar%20June%202023.pdf.

[27] U.S. Environmental Protection Agency (EPA), OAR, "Results Using Post-IRA 2022 Reference Case," Data and Tools, accessed October 2, 2023, https://www.epa.gov/power-sector-modeling/results-using-post-ira-2022-reference-case.

[28] U.S. Environmental Protection Agency (EPA), *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, EPA-452/R-23-006, 2023, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

[29] U.S. Environmental Protection Agency (EPA), *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, EPA-452/R-23-006, 2023, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

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

[31] U.S. Environmental Protection Agency (EPA), OAR, "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants," Other Policies and Guidance, April 25, 2023, https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

[32] U.S. Environmental Protection Agency (EPA), *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, EPA-452/R-23-006, 2023, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

[33] U.S. Environmental Protection Agency (EPA), "Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule," accessed October 2, 2023, https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf, p. 6.

[34] U.S. Energy Information Administration (EIA), "Frequently Asked Questions: How Much Carbon Dioxide Is Produced per Kilowatt-hour of U.S. Electricity Generation?," accessed October 2, 2023, https://www.eia.gov/tools/faqs/faq.php?id=74&t=11.

[35] U.S. Energy Information Administration (EIA), "Electricity Data Browser - Net Generation for All Sectors," accessed October 2, 2023, https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvv&geo=g&sec=g&linechart=ELEC.GEN.ALL-US-99.A~ELEC.GEN.COW-US-99.A~ELEC.GEN.NG-US-99.A~ELEC.GEN.NUC-US-99.A~ELEC.GEN.HYC-US-99.A~ELEC.GEN.WND-US-99.A~ELEC.GEN.TSN-US-99.A&columnchart=ELEC.GEN.ALL-US-99.A~ELEC.GEN.COW-US-99.A~ELEC.GEN.NG-US-99.A~ELEC.GEN.NUC-US-99.A~ELEC.GEN.HYC-US-99.A~ELEC.GEN.WND-US-99.A&map=ELEC.GEN.ALL-US-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=.

[36] "Emission Standards and Compliance Schedules," Code of Federal Regulations, Title 40 (1975): § 60.24, https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-B/section-60.24

[37] U.S. Environmental Protection Agency (EPA), "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Webinar for Communities with Environmental Justice Concerns and Members of Tribal Nations," June 2023, https://www.epa.gov/system/files/documents/2023-06/111%20Power%20Plants%20Stakeholder%20Presentation_Webinar%20June%202023.pdf.

[38] Sesame Sustainability. "Sesame | Decarbonizing Industry." Accessed October 23, 2023. https://www.sesamesustainability.com/.

[39] U.S. Energy Information Administration (EIA). "Annual Energy Outlook 2023, Table: Table 54, Electric Power Projections by Electricity Market Module Region, Case: Reference Case | Region: United States." Accessed October 23, 2023. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2023&cases=ref2023&sourcekey=0.

[40] U.S. Environmental Protection Agency (EPA). "Emissions & Generation Resource Integrated Database (eGRID)." Accessed October 23, 2023. https://www.epa.gov/egrid.

[41] U.S. Energy Information Administration (EIA), "State Profile and Energy Estimates - Arizona," accessed October 2, 2023, https://www.eia.gov/state/?sid=AZ#tabs-5.

[42] Clean Air Task Force (CATF), "Re: Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units (April 21, 2022), Docket ID No. EPA-HQ-OAR-2022-0289," June 6, 2022, https://cdn.catf.us/wp-content/uploads/2022/06/08125915/epa-ct-white-paper-comments.pdf?_gl=1*ckt4bv*_gcl_au*MTkwNzE1NjU4MC4xNjg5MTAwMzY2.

[43] EFI Foundation, *Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/20230212-CCS-Final_Full-copy.pdf.

[44] National Energy Technology Laboratory (NETL), "NETL Baseline Study Updated to Include the Performance and Cost of High Carbon Capture Rates for Power Generation Systems," accessed October 2, 2023, https://netl.doe.gov/node/12161.

[45] EFI Foundation, *Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/20230212-CCS-Final_Full-copy.pdf.

[46] EFI Foundation, *Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/20230212-CCS-Final_Full-copy.pdf.

[47] U.S. Department of Energy (DOE), *Pathways to Commercial Liftoff: Clean Hydrogen*, March 2023, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[48] U.S. Department of Energy (DOE), *Pathways to Commercial Liftoff: Clean Hydrogen*, March 2023, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[49] Rep. Peter A. DeFazio, [D-OR-4], Text - H.R.3684 - 117th Congress (2021-2022): Infrastructure Investment and Jobs Act, 2021, https://www.congress.gov/bill/117th-congress/house-bill/3684/text.

[50] U.S. Department of Energy (DOE), Office of Clean Energy Demonstrations (OCED), Funding Opportunity Announcement No.: DE-FOA-0002779, "Bipartisan Infrastructure Law: Additional Clean Hydrogen Programs (Section 40314): Regional Clean Hydrogen Hubs," September 1, 2023, https://oced-exchange.energy.gov/Default.aspx#FoaId4e674498-618c-4f1a-9013-1a1ce56e5bd3, p. 19.

[51] Energy Futures Initiative (EFI), *Building to Net-Zero: A U.S. Policy Blueprint for Gigaton-Scale CO2 Transport and Storage Infrastructure,* September 2021, https://efifoundation.org/wp-content/uploads/sites/3/2021/09/BuildingToNetZero_Report.pdf.

[52] Energy Futures Initiative (EFI), *Building to Net-Zero: A U.S. Policy Blueprint for Gigaton-Scale CO2 Transport and Storage Infrastructure,* September 2021, https://efifoundation.org/wp-content/uploads/sites/3/2021/09/BuildingToNetZero_Report.pdf.

[53] National Energy Technology Laboratory (NETL), "NATCARB/ATLAS," accessed October 18, 2023, https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas.

[54] Eric Larson, Chris Greig et al., "Net-Zero America: Potential Pathways, Infrastructure, and Impacts," Princeton University, October 29, 2021, https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf.

[55] Energy Futures Initiative (EFI), *Building to Net-Zero: A U.S. Policy Blueprint for Gigaton-Scale CO_2 Transport and Storage Infrastructure*, September 2021, https://efifoundation.org/wp-content/uploads/sites/3/2021/09/BuildingToNetZero_Report.pdf.

[56] EFI Foundation, *Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/20230212-CCS-Final_Full-copy.pdf.

[57] Energy Futures Initiative (EFI), *Building to Net-Zero: A U.S. Policy Blueprint for Gigaton-Scale CO_2 Transport and Storage Infrastructure*, September 2021, https://efifoundation.org/wp-content/uploads/sites/3/2021/09/BuildingToNetZero_Report.pdf.

[58] Congressional Research Service (CRS), "Carbon Dioxide Pipelines: Safety Issues," June 3, 2022, https://crsreports.congress.gov/product/pdf/IN/IN11944.

[59] Jack Dura, "South Dakota Panel Denies Application for CO2 Pipeline; Summit to Refile for Permit," *Associated Press*, September 11, 2023, sec. U.S. News, https://apnews.com/article/south-dakota-north-dakota-co2-pipeline-summit-827c7418edba5a4ecbd7501be02d84f9.

[60] U.S. Energy Information Administration (EIA), "U.S. Energy Facts Explained," accessed January 10, 2023, https://www.eia.gov/energyexplained/us-energy-facts/.

[61] EFI Foundation, *The U.S. Hydrogen Demand Action Plan*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/EFI-Hydrogen-Hubs-FINAL-2-1.pdf.

[62] EFI Foundation, *The U.S. Hydrogen Demand Action Plan*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/EFI-Hydrogen-Hubs-FINAL-2-1.pdf.

[63] U.S. Department of Energy (DOE), *Pathways to Commercial Liftoff: Clean Hydrogen*, March 2023, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[64] U.S. Department of Energy (DOE), *Pathways to Commercial Liftoff: Clean Hydrogen*, March 2023, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[65] Kevin Topolski, Evan Reznicek et al., "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology," October 10, 2022, https://doi.org/10.2172/1893355.

[66] U.S. Department of Energy (DOE), *Pathways to Commercial Liftoff: Clean Hydrogen*, March 2023, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[67] U.S. Department of Energy (DOE), *Pathways to Commercial Liftoff: Clean Hydrogen*, March 2023, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[68] U.S. Department of Energy (DOE), *Pathways to Commercial Liftoff: Clean Hydrogen*, March 2023, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[69] EFI Foundation, *The U.S. Hydrogen Demand Action Plan*, February 2023, https://efifoundation.org/wp-content/uploads/sites/3/2023/02/EFI-Hydrogen-Hubs-FINAL-2-1.pdf.

[70] U.S. Department of Energy (DOE), Office of Clean Energy Demonstrations (OCED), Funding Opportunity Announcement No.: DE-FOA-0002779, "Bipartisan Infrastructure Law: Additional Clean Hydrogen Programs (Section 40314): Regional Clean Hydrogen Hubs," September 1, 2023, https://oced-exchange.energy.gov/Default.aspx#FoaId4e674498-618c-4f1a-9013-1a1ce56e5bd3, p. 19.

[71] Szoka et al., "Energy Solutions for North Carolina," Pub. L. No. 951, § 165 (n.d.), https://www.ncleg.gov/BillLookUp/2021/H951.

[72] "North Carolina - Climate-XChange State Climate Policy Network Map," *Climate-XChange* (blog), accessed October 3, 2023, https://climate-xchange.org/dashboard/map/north-carolina/.

[73] Duke Energy Corp., "Generating Energy from Coal," accessed October 18, 2023, https://www.duke-energy.com/energy-education/how-energy-works/energy-from-coal.

[74] U.S. Energy Information Administration (EIA), "Michigan - Profile Analysis," August 17, 2023, https://www.eia.gov/state/analysis.php?sid=MI.

[75] Gretchen Whitmer, "Executive Directive 2020-10," September 23, 2020, https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10.

[76] Cory Connolly, "MI Healthy Climate Plan," Michigan Department of Environment, Great Lakes, and Energy, accessed October 3, 2023, https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan.

[77] Climate-XChange, "Michigan - Climate-XChange State Climate Policy Network Map," July 2023, https://climate-xchange.org/dashboard/map/michigan/.

[78] Proos, "Enrolled Senate Bill No. 438," Pub. L. No. 438 (2016), http://www.legislature.mi.gov/documents/2015-2016/publicact/htm/2016-PA-0342.htm.

[79] State Policy Opportunity Tracker, "Michigan - Grid Modernization Plan," accessed October 3, 2023, https://spotforcleanenergy.org/state/michigan/grid-modernization-plan/.

[80] Gov. Gretchen Whitmer, "Michigan Leads on Hydrogen," accessed October 18, 2023, https://www.michigan.gov/whitmer/issues/michigan-infrastructure-office/michigan-leads-on-hydrogen.

[81] Karin Rives, "Michigan Legislation Proposes 2030 Coal Phase-out, Fossil-Free Energy by 2035," S&P Global, April 14, 2023, https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/041423-michigan-legislation-proposes-2030-coal-phase-out-fossil-free-energy-by-2035.

[82] U.S. Bureau of Economic Analysis, "Regional Data - GDP and Personal Income," accessed October 3, 2023, https://apps.bea.gov/itable/?ReqID=70&step=1&acrdn=1#eyJhcHBpZCI6NzAsInN0ZXBzIjpbMSwyOSwyNSwzMSwyNiwyNywzMF0sImRhdGEiOltbIlRhYmxlSWQiLCI2MDAiXSxbIk1ham9yX0FyZWEiLCIwIl0sWyJTdGF0ZSIsWyIwIl1dLFsiQXJlYSIsWyI0MjAwMCJdXSxbIlN0YXRpc3RpYyIsWyItMSJdXSxbIlVuaXRfb2ZfbWVhc3VyZSIsIkxldmVscyJdLFsiWWVhciIsWyIyMDIyIl1dLFsiWWVhckJlZ2luIiwiLTEiXSxbIllYXJfRW5kIiwiLTEiXV19.

[83] U.S. Energy Information Administration (EIA), "Pennsylvania - Profile Analysis," November 17, 2022, https://www.eia.gov/state/analysis.php?sid=MI.

[84] Commonwealth of Pennsylvania, Governor's Office. Executive Order, Commonwealth Leadership in Addressing Climate Change and Promoting Energy Conservation and Sustainable Governance, Pub. L. No. 2019–01 (2019). https://www.oa.pa.gov/Policies/eo/Documents/2019-01.pdf.

[85] Pennsylvania Department of Environmental Protection, "PA Climate Action Plan," accessed October 3, 2023, https://www.dep.pa.gov:443/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx.

[86] State Policy Opportunity Tracker, "Michigan - Grid Modernization Plan," accessed October 3, 2023, https://spotforcleanenergy.org/state/michigan/grid-modernization-plan/.

[87] Pennsylvania General Assembly, "Title 66,"2004, https://www.legis.state.pa.us/cfdocs/legis/LI/consCheck.cfm?txtType=HTM&ttl=66&div=0&chpt=28&sctn=14&subsctn=0.

[88] Climate-XChange, "Pennsylvania - Climate-XChange State Climate Policy Network Map," July 2023, https://climate-xchange.org/dashboard/map/pennsylvania/.

[89] U.S. Energy Information Administration (EIA), "The Largest Coal-Fired Power Plant in Pennsylvania Will Close by July 2023," Today in Energy, accessed October 18, 2023, https://www.eia.gov/todayinenergy/detail.php?id=56700.

UNITED STATES OF AMERICA

BEFORE THE

U.S. ENVIRONMENTAL PROTECTION AGENCY

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule	EPA-HQ-OAR-2023-0072

JOINT COMMENTS OF ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.; MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.; PJM INTERCONNECTION, L.L.C.; AND SOUTHWEST POWER POOL, INC.

Introduction and Summary

Electric Reliability Council of Texas, Inc. ("ERCOT"), Midcontinent Independent System Operator, Inc. ("MISO"), PJM Interconnection, L.L.C. ("PJM"), and Southwest Power Pool, Inc. ("SPP") (collectively, "Joint ISOs/RTOs"), jointly submit these comments in response to the Environmental Protection Agency's ("EPA") proposed rule in the above-referenced docket ("Rule" or "Proposed Rule").[1] As described below, the Joint ISOs/RTOs are concerned that the substance of the Proposed Rule as presently configured, as well as its timing, have the potential to materially and adversely impact electric reliability. Moreover, the Proposed Rule, when combined with other EPA rules and other policy actions, could well exacerbate the disturbing trend and growing risk wherein the pace of retirements of generation with attributes needed to ensure grid reliability is rapidly exceeding the commercialization of new resources capable of providing those reliability attributes.

I. Overview of Joint ISOs/RTOs' Concerns

The Joint ISOs/RTOs have long been at the forefront of renewable energy integration, but have seen an increasing trend of retirements of dispatchable generation, which provides critical attributes that are needed to support the reliable operation of the grid. Although each region is working to facilitate a substantial increase in renewable generation, the challenges and risks to grid reliability associated with a diminishing amount of dispatchable generating capacity could be severely exacerbated if the Proposed Rule is adopted.

We recognize that through the creation of various sub-categories, the EPA has attempted to stagger the impact of the rule to avoid an *en masse* retirement of needed dispatchable generation.

[1] Individual RTOs and ISOs reserve the right to submit separate, supplemental comments on this rule.

However, key requirements in the Proposed Rule are premised on EPA's assumption that either (1) the development of new technologies will allow new, low-greenhouse gas (GHG) resources to substitute for the resources presently providing these necessary reliability attributes or grid services or (2) the retrofitting of fossil-based resources with either carbon capture and storage (CCS) or hydrogen co-firing to control carbon dioxide (CO_2) emissions will be economically feasible within the timeframes specified for compliance in the Proposed Rule. Although the Joint ISOs/RTOs have been and will continue to be supportive of new technologies, we believe that the Proposed Rule's Best System of Emissions Reduction (BSER) determination overstates the commercial viability of CCS and hydrogen co-firing today and ignores the cost and practicalities of developing new supporting infrastructure within the time frames projected. Without firm proof of the commercial and operational viability of these technologies, proceeding with these requirements could place the reliability of the electric grid in jeopardy. In short, hope is not an acceptable strategy.

These concerns are not limited to the future years in which the Proposed Rule would require these new technologies to be employed. The Joint ISOs/RTOs are equally concerned that the Rule (and the cumulative effect of all of the recent electric industry-related EPA actions and rulemakings) could have a chilling effect in the near-term on the investment needed to maintain dispatchable generating units until these new technologies develop. The ISOs/RTOs are already seeing retirements of generators that are concerning as they appear to be driven by a reluctance of investors to make the commitments needed to keep these capital-intensive resources operating. As the penetration of renewable resources continues to increase, the grid will need to rely even more on generation capable of providing critical reliability attributes. With continued and potentially accelerated retirements of dispatchable generation, supply of these reliability attributes will dwindle to concerning levels.

We appreciate previous efforts by the EPA to address reliability concerns raised by the Joint ISOs/RTOs through commitments to enforcement discretion (in the case of the MATS Rule) or the adjustment of compliance dates. However, these solutions do not ensure that resource owners will make sufficient investments in resource maintenance in the years preceding the effective date of the Rule, as those investments are based in part on the forecast of the viability of a given set of units. As a result, the Proposed Rule can have negative impacts on electric grid reliability even before the effective date of this rule.

Accordingly, the Joint ISOs/RTOs urge the EPA to further examine and address these reliability impacts before finalizing any Rule in this area. Joint ISOs/RTOs submit these comments to explain the challenges associated with the Proposed Rule and underscore the need for actions to address reliability concerns within any future final rule. These comments are organized as follows

A. Overarching Reliability Concerns
B. Shortcomings in EPA's Reliability Analysis Assumptions
C. Comments Regarding Revised New Source Performance Standards (NSPS) for GHG Emissions from New Fossil Fuel-Fired Stationary Combustion Turbine EGUs
D. Comments Regarding Emission Guidelines for GHG Emissions from Existing Fossil Fuel-Fired Steam Generating EGUs
E. Comments Regarding Emission Guidelines for GHG Emissions from Existing Stationary Combustion Turbines

F. Need to Incorporate Timely Reviews of Technology Advancement and Unit Retirements in the Final Rule
G. Request for Specific EPA Authorization for Interstate Allowance Trading Among Affected Units
H. Request to Revise the Definition of "System Emergency"

II. Joint ISOs/RTOs' Proposed Modifications Should the Rule Go Forward

The Joint ISOs/RTOs appreciate the dialogue in which EPA has engaged with us in the past, and we wish to maintain our constructive working relationship with the EPA. As noted above, we believe the EPA must conduct further analyses and address reliability impacts before finalizing any Rule in this area. However, should the EPA nevertheless decide to adopt a rule, the Joint ISOs/RTOs propose several additional features that would help to partially mitigate, albeit not eliminate, these reliability impacts going forward. At a high level, these additional features include:

- Specification of a new sub-category for existing units, providing a time-limited means for ISOs/RTOs to designate classes of units that are needed to maintain local or region-wide reliability until alternatives (which may be new transmission or new generation or storage resources) are available to address the identified reliability need;[2]

- Building into the Rule a process to monitor and adjust the Rule's compliance schedule as applied to existing gas and coal units based on an examination as to whether the CCS and hydrogen co-firing infrastructure is developing at a sufficient pace to allow implementation in the time frame contemplated by the Proposed Rule. Such an ongoing review built into the Rule itself can help to balance of the pace of retirements of dispatchable generation needed to provide critical grid services with the new additions providing such grid services;

- Providing specific recognition in the Rule of the availability of allowance trading on a regional, if not national level to allow for greater flexibility and incentivize early and effective 'over-compliance' by those units that are capable of so doing;

- Updating the definition of 'System Emergency' to reduce uncertainty around when a unit may be called upon for reliability.

Additional details would certainly need to be addressed regarding these proposals. The specific reforms outlined herein have been developed to work within the structure of the Proposed Rule and the applicable law. Given the breadth of the impact of any risks to electric reliability, the Joint ISOs/RTOs would urge EPA to collaborate with the ISOs/RTOs, stakeholders, and states to develop the details of these measures, if the EPA proceeds with the Proposed Rule. The Joint ISOs/RTOs look forward to continued dialogue and analytical work with the EPA on the reliability impacts of the Proposed Rule and, if appropriate, the proposed modifications outlined above.

---

[2] As further described in these Comments, this could also be accomplished through the creation of a presumptive, automated reliability process through use of the remaining useful life and other factors (RULOF) provisions included in 40 C.F.R. § 40.60.24a(e).

Background

The Joint ISOs/RTOs are charged with maintaining the reliability of the bulk power system that provides electric service to over **154** million Americans. The geographic reach of the Joint ISOs/RTOs is broad, encompassing an area of approximately 2 million square miles, in all or parts of 30 states and the District of Columbia.

The Joint ISOs/RTOs carry out this reliability responsibility by:

- Dispatching generation and demand response resources in real time to meet the minute-by-minute demands of electricity customers;
- Operating real time and day ahead energy markets that ensure the most efficient dispatch of resources to meet demand in a given hour;
- Ensuring resource adequacy to meet projected future demands for electricity by operating wholesale markets and partnering with states;
- Planning the expansion of the transmission system to meet the reliability needs of customers; and
- Interconnecting new generation resources to the grid.

Each of the Joint ISOs/RTOs are independent of market participants and operate on a revenue-neutral basis. The Joint ISOs/RTOs are also technology-neutral, favoring neither fossil nor renewable generation, and treat all resources on a nondiscriminatory basis, as required by relevant laws.

Comments

A. *Overarching Reliability Concerns*

As a threshold matter, the Joint ISOs/RTOs are concerned that the Proposed Rule could result in material, adverse impacts to the reliability of the power grid. These reliability concerns primarily arise from the possibility that the significant technological advances in low-greenhouse gas (GHG) hydrogen production, transport and generation, as well as in carbon capture and storage (CCS) that are identified as BSER under the Proposed Rule may not occur as anticipated, or may not occur at the pace anticipated by the EPA. If the technology and associated infrastructure fail to timely materialize, then the future supply of compliant generation—given forced retirements of non-compliant generation—would be far below what is needed to serve power demand, increasing the likelihood of significant power shortages.

The EPA projects these technologies will prove economic over the compliance period as a result of subsidies built into the Inflation Reduction Act.[3] While technology development and commercialization of these technologies at a reasonable cost is not entirely out of the question, those technologies are not yet feasible on a large scale, and there are reasons to be skeptical that it will be widely available on the timeline anticipated by EPA. Low-GHG hydrogen and CCS require the development of vast new and costly infrastructure. CCS has only been implemented in two isolated

[3] Inflation Reduction Act of 2022

cases. Although the Joint ISOs/RTOs have no opposition to the development of these new technologies and, in some cases, have become platforms for their testing, the record is not sufficiently developed to determine that these technologies support a BSER finding at this time.

The Joint ISOs/RTOs are concerned that the proposed rule would greatly exacerbate an ongoing loss of critical, dispatchable generating capacity that is needed to ensure grid reliability. Over recent years, Joint ISOs/RTOs have each observed an increasing level of dispatchable generation retirements without the comparable addition of new technologies that would provide the same level of grid support.[4] Although each of the Joint ISOs/RTOs is seeing a rapid growth in renewable and energy storage resources interconnecting to the grid, given the intermittent and energy-limited nature of those resources, their capacity (or accredited) value is substantially discounted from the capacity (or accredited) value of thermal generation today. In addition, these new resources connecting to the grid are primarily inverter-based, and have distinctly different characteristics than synchronous machines.[5] Although providing valuable carbon-free electricity, these new resources do not, at present, provide the same levels of essential reliability services – or attributes – as their thermal counterparts. New technologies and industry practices are developing to enable the integration of significant inverter-based generation that provide needed essential reliability services, but the Joint ISO/RTOs 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. The ISO/RTO-specific appendices to these Comments detail experiences, studies, and concerns by region.[4]

Finally, the Joint ISOs/RTOs are also concerned about the chilling impact of the Proposed Rule on investment required to retain and maintain existing units that are needed to provide key attributes and grid services *before* the compliance date required by the rule. Investments are based, in part, on the expected revenues associated with continuing operation of the unit. Unit owners may decide to retire units early rather than incur additional expense and risk. Alternatively, should the units remain operational, with the expectation of retirement at a future date certain, then unit owners may forgo required maintenance in the interim because of the lower return on the investment from doing so. The failure to properly maintain generating units can lead to a higher incidence of forced outages of these units, diminishing the dispatchable generation supply in the interim.

As a result, the Joint ISOs/RTOs believe that the record is insufficient for the EPA to conclude that the Proposed Rule will not adversely impact reliability. The EPA should therefore reconsider moving forward with the Proposed Rule in its present form.

However, if the EPA is inclined to move forward with the Proposed Rule, the Joint ISOs/RTOs would urge the EPA to at least include several additional features in the rule to help mitigate, although not eliminate, these reliability impacts. These features include:

- Specification of a new sub-category for existing units, providing a time-limited means for ISOs/RTOs to designate classes of units that are needed to maintain local or region-wide

---

[4] See ISO/RTO specific Appendices (1-4) for information applicable to each ISO/RTO.

[5] See NERC Introduction to Inverter-Based Resources on the Bulk Power System.

reliability until alternatives, which may be new transmission or new generation or storage resources, are available to address the specific identified reliability need[6];

- Building into the Rule a process to monitor and adjust the compliance schedule as applied to existing gas and coal units based on an examination as to whether the CCS and hydrogen co-firing infrastructure is developing at a sufficient pace to allow implementation in the time frame contemplated by the Proposed Rule. Such an ongoing review built into the Rule itself will ensure a better balance of the pace of retirements of dispatchable generation needed to provide critical grid services with the new additions providing such grid services;

- Providing specific recognition in the Rule of the availability of allowance trading on a regional, if not national, level to allow for greater flexibility and incentivize early and effective "over-compliance" by those units that are capable of doing so;

- Updating the definition of "System Emergency" to reduce uncertainty around when a unit may be called upon for reliability.

These comments will describe the reliability concerns highlighted above and then address the specific rule features proposed by the Joint ISOs/RTOs.

B. ***Shortcomings in EPA's Reliability Analysis Assumptions***

EPA's Resource Adequacy Analysis Technical Support Document[7] does not address the range of reliability issues that the proposed Rule could trigger, but, rather by its own terms, is solely focused on resource adequacy. While EPA distances itself from potential impacts to the grid, EPA acknowledges that resource adequacy on its own is "not sufficient" for determining grid reliability:

> *"While such potential impacts would not be a direct result of these rules but rather of the compliance choices source owners and operators may pursue, we have analyzed whether the projected effects of the rules would in this regard pose a risk to resource adequacy, a key planning metric that is necessary (but not sufficient) for grid reliability*."[8]

The Joint ISOs/RTOs' reliability duties extend beyond resource adequacy and include the provision of essential reliability services that are critical to the grid.[9] Power-industry-defined reliability attributes include inertia, primary frequency response, reactive power support, system stability, system strength, frequency regulation, ramping, flexibility, dispatchability, black start capability, fuel and energy assurance, and extreme weather performance. The Joint ISOs/RTOs urge EPA to work with the Joint ISOs/RTOs in assessing the proposal's impact on reliability, incorporating additional metrics around essential reliability services and attributes.

---

[6] This could also be accomplished through the creation of a presumptive, automated reliability process via remaining useful life and other factors (RULOF) provisions included in Code of Federal Regulations Title 40. Protection of Environment § 40.60.24a(e).
[7] Resource Adequacy Analysis TSD, page 2.
[8] Resource Adequacy Analysis TSD, page 3
[9] Energy Transition in PJM: Frameworks for Analysis.

EPA's underlying assumptions for the Resource Adequacy Analysis are dependent on modeling the 2022 Inflation Reduction Act (IRA) in the base case. In the Joint ISOs/RTOs' view, the base-case modeling masks the impact of the proposed Rule by assuming that the retirements have occurred independent of the Proposed Rule. Because the base case shows significant coal and nuclear retirements, renewable and storage additions, and a significant decline in energy generated from natural gas while natural gas capacity significantly increases, the resulting comparison to the modeled proposal shows little impact to the system. This ignores the cumulative impact of the various EPA rules and their intertwined nature, leaving an incomplete picture of the impact of the GHG rule on unit retirement decisions and resource adequacy. This analysis also does not consider the impacts to minimum resource adequacy requirements caused by a changing resource mix. In other words, replacement of dispatchable generation by generation that is, by its nature, not as dispatchable will, among other items, drive requirements for larger amounts of generation (nameplate capacity) in order to maintain an equivalent amount of reliability.

To explore the ability to rely on modeled projections of the impact of the IRA on the grid as a basis for adequately projecting grid reliability, the Joint ISOs/RTOs added EPA modeling projections[10] to a recent third party comparison of numerous models that all attempted to model grid impacts of the IRA by Bistline, et al. (2023) "Emissions and Energy Impacts of the Inflation Reduction Act"[11] and found a continuation of the "substantial variation" noted by the authors, in projected capacity and generation (as illustrated in Figure 1 below). The authors point out the difficulty in modeling the IRA:

> "*Models attempt to capture many economic factors that could influence technology adoption, but several implementation challenges are difficult to model, including the scale-up of supply chains and materials, siting and permitting, infrastructure expansion, network effects, non-cost barriers to consumer uptake of incentives, and the economic incidence of subsidies*."[12]

The authors add that:

> *"Additional analysis is important for understanding potential impacts of partial coverage of IRA provisions and IRA implementation uncertainties, as well as uncertainties about external factors*,

[10] Analysis of the Proposed Greenhouse Gas Standards and Guidelines: Power Sector Modeling

[11] Data for Bistline, et al. (2023) "Emissions and Energy Impacts of the Inflation Reduction Act",

[12] "Emissions and Energy Impacts of the Inflation Reduction Act," *Science*, June 30, 2023, Vol 380, Issue 6652, Page 1327.

including inflationary trends, domestic macroeconomic environment, and global drivers."

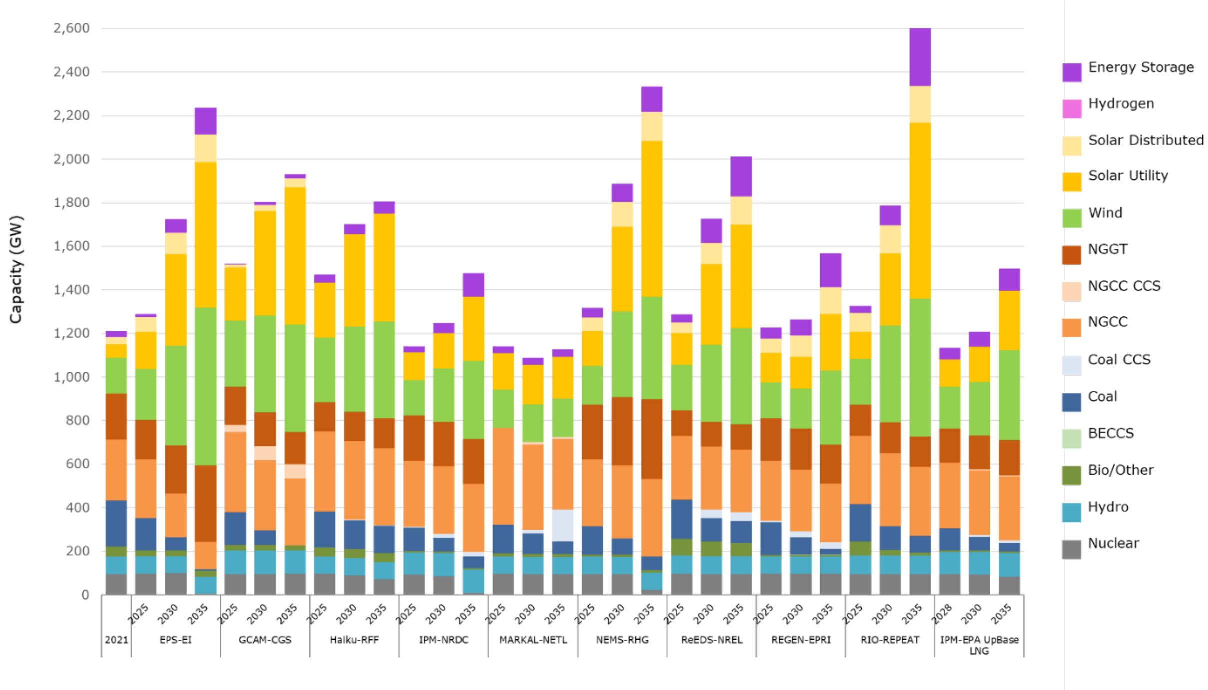


Figure 1: Projected Capacity when Modeling the Inflation Reduction Act.

(Figure from the Bistline analysis supplemented by the Joint ISOs/RTOs to include the projected capacity from the *IPM-EPA Updated Baseline with LNG Update* released on July 7.[13])

As mentioned above, EPA should undertake additional analysis that reflects supply chain constraints, real world siting and permitting expense and timelines, requisite infrastructure expansion and the maintenance of essential grid reliability attributes in order to provide a full assessment of the Rule's potential reliability impacts. The Joint ISOs/RTOs, each of whom administer interconnection queues for new resources, have information that would be informative to that analysis.

C. ***Comments Regarding Revised New Source Performance Standards (NSPS) for GHG Emissions from New Fossil Fuel-Fired Stationary Combustion Turbine EGUs.***

The Joint ISOs/RTOs are concerned that the BSER findings for new fossil fuel-fired stationary combustion turbines lead to assumptions about new generation capacity construction that simply are infeasible and uneconomic at the levels proposed. EPA's and others' modeling shows little to no generation applying the BSER control technologies (CCS and co-firing low GHG Hydrogen) in the future,[14] pointing to, among other factors, the current and less-than-beneficial economics of those technologies in the future (see Figure 1 above). As such, we recommend EPA conduct the BSER determination again, focusing, for example, on levels of co-firing that could be ***economically and practically achievable*** in the timeframe cited. For example, if BSER were determined to be co-firing 30% hydrogen, this would

[13] Data for Bistline, et al. (2023) "Emissions and Energy Impacts of the Inflation Reduction Act."
[14] See Appendix 1 for modeled capacity projections of coal with CCS, natural gas with CCS and hydrogen.

increase the potential of being achievable in some locations under today's combustion technology, hydrogen production and national pipeline infrastructure. On the flip side, co-firing with hydrogen at 96% or installing CCS on a mass scale would undoubtedly require the development of a vast new infrastructure that could take many years to develop. As a result, in this example, a BSER based on more realistic levels for hydrogen co-firing might serve to promote the hydrogen industry and associated infrastructure in a more feasible fashion, while potentially mitigating the large upfront cost and system retrofits needed to co-fire at the much higher levels found in the Proposed Rule, which could help reduce the obstacles to new generation construction. Such a more graduated approach would also recognize that EPA retains the ability to review the NSPS at least every eight years and adjust the BSER accordingly as technology, economics, and the bulk power system evolves. By the same token, adoption of the Joint ISOs/RTOs' proposal on interstate emissions trading would allow unit owners to potentially comply with the Rule while recognizing that the availability of infrastructure to transport and produce hydrogen, and the infrastructure necessary to transport and store carbon dioxide from CCS, varies across the nation. This proposal is discussed in further detail in Section VII below.

D. ***Comments Regarding Emission Guidelines for GHG Emissions from Existing Fossil Fuel-Fired Steam Generating EGUs***.

Subject to the reliability concerns identified above, the Joint ISOs/RTOs offer the following recommendations for the EPA's consideration.

1. Combining Certain of the Proposed Rule's Subcategories

The Joint ISOs/RTOs recommend the subcategories for existing fossil fuel-fired steam generating EGUs be modified to improve flexibility and help mitigate reliability concerns. We recommend EPA modify the proposed subcategories for existing coal units. The current proposal is:

(A) *Long-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have not adopted enforceable commitments to cease operations by January 1, 2040.

(B) *Medium-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2040, and that are not near-term units.

(C) *Near-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2035, and elected to commit to adopt an annual capacity factor limit of 20 percent.

(D) *Imminent-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date before January 1, 2032.

In order to promote the economic, in-market, near-term retention of resources necessary to the reliability of the grid, the Joint ISOs/RTOs propose that the above subcategories (C) and (D) be combined into one subcategory entitled *Near-term existing coal-fired steam generating units*, which consist of coal-fired steam generating units that have elected to commit to permanently cease operations by a date before January 1, 2035. These units would not have any limitation on their capacity factor and would apply what EPA has branded 'routine methods of operation' as BSER.

By the same token, the separate subcategory of units that commit to adopt an annual capacity factor of 20% ignores the fact that such a capacity factor limitation almost certainly renders these units uneconomic in the marketplace. In short, category (C) is not an economically viable category as few unit owners, particularly in states that have adopted retail choice and operate in competitive wholesale market areas, will be able to recover their going forward costs under such a limitation. This would contribute to the retirement risk concern that the Joint ISOs/RTOs have illustrated throughout these comments.

2. Creation of a New Reliability-Based Sub-Category

The Joint ISOs/RTOs propose the adoption of an additional sub-category that would accommodate units deemed needed for reliability, whether natural gas or coal. This subcategory would be populated with specific units or locations as identified by the ISO/RTO where unit retirement would cause significant reliability challenges until other longer-term solutions, such as transmission, demand response, or new generation resources, would obviate the need for those units. The ISO/RTO would identify these units or locations to EPA and a unit's placement in this sub-category would allow the non-compliant units to continue to operate beyond the date of compliance with the rule until the alternative solution can be placed into service.

As a threshold matter, each ISO/RTO would provide a public explanation of the methodology it would use to determine which units, or classes of units, qualify for inclusion in this subcategory and the process for identification of such units. The ISO/RTO would then conduct a unit or location-specific reliability analysis for each of these units. The analysis would establish the defined period past the initial retirement date that the unit is needed to maintain grid reliability while measures are implemented to address reliability issues caused by the affected unit's retirement. Within the bounds of respecting the confidential nature of certain commercially sensitive information, the ISO/RTO would publish its analysis for review and feedback from industry stakeholders. Completion of that analysis would then trigger an identification of those units or classes of units in a given location to the EPA. EPA would give deference to the ISO/RTO determination. Units ultimately identified as needed for reliability would not be subject to compliance until the date after which the unit is needed for reliability.

A similar process is already in place for the designation of units as eligible for Reliability Must Run (RMR) agreements. The Joint ISOs/RTOs' proposal is to incorporate into the Final Rule the means by which this existing RMR process would be linked to the new process in the Proposed Rule so that the two can complement rather than conflict with one another.

To be clear, the reliability sub-category is not a panacea. It still would leave generation owners with considerable uncertainty as they assess the long-term future of market participation. However, if exercised sufficiently in advance, with clear and transparent checks to prevent its over-use, the sub-category designation could be a useful tool to preserving those unit(s), either locationally or by class, so as to avoid their premature retirement before alternative commercial technologies have developed and can be deployed economically and practically to address reliability.

Another circumstance which would justify a unit being placed into this subcategory exists where a unit commits to implementing a control technology, but for reasons beyond its control, is unable to do so. While the EPA may have the authority to enter into an agreement to extend the compliance date, the Joint ISOs/RTOs recommend a process be incorporated into the rule itself that addresses the risk to the unit for continued operation, and the risk to reliability. The goal would be to avoid a situation in which the unit owner would need to comply or else a Department of Energy Section 202(c) emergency order would be required to continue the unit's operation, and to instead create a clear process where the reliability requirements are incorporated into the Rule.

The Joint ISOs/RTOs believe the creation of such a subcategory in the Rule is entirely consistent with the EPA's existing authority under Section 111 of the Clean Air Act. That Section provides significant discretion to EPA to establish subcategories based on source type, class, or size.[15]

3. Use of Remaining Useful Life and Other Factors (RULOF) Authority

A complementary approach to the above creation of a reliability sub-category would be for EPA to establish a presumptive, automated reliability process under which the ISO/RTO would certify that a unit is needed for reliability for a certain period, and then each affected state could then incorporate that certification in its plan, as contemplated by CAA 111(d):

> *"Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."*

The ISO/RTO determination in this case would be anchored in an analysis of the remaining useful life of a unit needed for grid reliability and forces which may drive its premature retirement. Use of this flexibility is not new. EPA currently considers a formal reliability assessment from ISOs/RTOs in implementing conditions of the Coal Combustion Residuals rule.[16] This process will allow the required unit to continue to operate for the required period of time, applying routine methods of operation, to address grid reliability.

E. *Comments Regarding Emission Guidelines for GHG Emissions from Existing Stationary Combustion Turbines*

Certain individual ISOs/RTOs have conducted studies on integrating increasingly higher penetrations of renewable resources into the grid. These studies have found that as the resource mix continues to evolve, it is crucial for reliability purposes to maintain certain levels of resources with attributes such as quick start-up and ramping capabilities, synchronous connection to the grid, and

[15] Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act,
[16] Final Decision: Denial of Alternative Closure Deadline for General James M. Gavin Plant, Cheshire, Ohio, page 85.

ability to operate for both short and long periods of time.[17] Currently, natural gas-fired combustion turbines are a major source of these needed reliability attributes. Someday, other types of resources such as long-duration battery storage may become commercially and economically viable enough to provide these critically needed attributes at grid scale for long durations. But unless or until that happens, it will be critical to ensure a sufficient amount of dispatchable generation remains available to offset the intermittent nature of renewables on grid reliability. Additionally, there may also be a need to build dispatchable resources such as new natural gas combustion turbines in the coming years to ensure that grid reliability is not jeopardized as emerging technologies with needed reliability attributes continue to mature towards grid-scale viability. As such, the Joint ISOs/RTOs wish to ensure that the Final Rule not serve as an impediment to the operation of these resources to the extent they provide critical grid services. With the increasing amounts of renewables and storage, we expect the dispatchable fossil fleet to run fewer hours, but until wide commercialization of alternatives such as long duration storage and grid-forming inverters come into alignment with the pace of retirements, the Rule should not, through strictures on capacity factors, drive the premature retirement of units that provide such critical grid services.

EPA projects that 37 GW of gas capacity will be in the greater than 300 MW and greater than 50 percent annual capacity factor subcategory for existing stationary combustion turbines on a nationwide basis in 2035.[18] Recent analysis by BTU Analytics estimates 73 GW potentially impacted by the proposal.[19] Should this significant portion of capacity nation-wide be required to either co-fire hydrogen, install carbon capture and sequestration, or reduce capacity factors to 50% or below, this would have significant implications to a grid that is otherwise increasingly dependent on this resource in the near term. For regions with a relatively small quantity of no- or low-carbon emitting resources, these requirements may also have the unintended impact of increasing emissions if required energy is met by units with higher emission rates.

F. ***Need to Incorporate Timely Reviews of Technology Advancement and Unit Retirements in the Final Rule***

As noted above, the compliance deadlines set forth in the Rule are premised on the timely development of new technology as a result of the IRA. The compliance deadlines also assume that the pace of new resources can keep up with if not surpass the rate of retirement of generation providing the key attributes needed to keep the grid in balance.

If these optimistic assumptions come to pass, the Final Rule may not have a significant adverse impact on reliability; however, if they do not, the reliability challenges remain and become more critical with each passing year. For these reasons, the Joint ISOs/RTOs urge that the Final Rule specify a process for evaluating on a regularly scheduled basis, the assumptions that informed the compliance schedule and, if necessary, delay the implementation date of the rule based on the pace of technology development as well as the pace of retirements compared with the rate of new generation

[17] "The integration of renewable resources increases the need for balancing resources to meet forecasted ramping requirements." Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, Page 2.
[18] Proposed Rule, 33,361
[19] U.S. EPA Climate Rule Could Affect Twice as Much Gas- Fired Capacity as Agency Projects.

development. The Joint ISOs/RTOs recognize that EPA is already required to conduct a review of New Source Performance Standards at least every eight years.[20] However, because of the breadth of the Proposed Rule and the intertwined nature of these assumptions with the compliance deadlines, this review should occur more frequently than once every eight years. Moreover, the analysis of generator retirements and additions should be focused on longer-term reliability impacts, and should therefore supplement, not replace, the use of the reliability sub-category for specific units or locations as outlined above.

Notwithstanding certain stakeholder concerns regarding the finality of the original BSER determination, this review would be focused on the compliance calendar. Such a periodic review with the potential for course-correction is entirely consistent with the principles underlying the EPA's existing eight-year review process and can easily be accomplished within the four corners of the Clean Air Act. The Joint ISOs/RTOs urge adoption of this feature and its specific inclusion in the Final Rule.

G. ***Request for Specific EPA Authorization for Interstate Allowance Trading Among Affected Units***

In the Final Rule, the EPA should expressly provide for allowance trading as a means of compliance. As the Preamble to the GHG Rule recognizes, allowance trading has proven successful in similar environmental programs dating back to the SO_2 rule in the 1990s, providing flexibility and bringing down the overall cost of compliance.[21] Moreover, since the GHG rule is premised on the development and deployment of new technologies, a large-scale allowance trading program would provide incentives for the development and deployment of these technologies as allowance trading provides a means for those unit owners who can 'over-comply' with the rule to monetize the value of that over-compliance while providing flexible options for other unit owners who face more costly compliance.

The Proposed Rule recognizes the benefits of allowance trading, but takes no position and provides limited direction on this subject, especially as to the potential for interstate trading.[22] On the other hand, the Preamble seeks comment as to whether the proposed subcategories obviate the need and benefit of allowance trading as part of a compliance strategy.[23]

The Joint ISOs/RTOs do not agree with EPA's tentative conclusion that the specific subcategories for existing coal-fired steam generating units and existing gas combustion turbines "provide for much of the same operational flexibility as would be provided through trading." We remain equally concerned with EPA's tentative conclusion that allowance trading as a compliance strategy:

> "*would not be appropriate to allow affected EGUs in certain subcategories—imminent-term and near-term coal-fired steam generating units and natural gas and oil-fired steam generating units—to comply with their standards of performance through trading*."[24]

---

[20] 42 USC § 7411(b)(1)(B)
[21] Proposed Rule, 33,393
[22] Proposed Rule, 33,393-33,396
[23] Proposed Rule, 33,393
[24] Proposed Rule, 33,393

As noted in these Comments, the Joint ISOs/RTOs believe that the Rule may force the premature retirement of those imminent and near-term dispatchable units prior to the commercialization of replacement generation with similar attributes or capabilities to provide grid services. Yet, by touting the staggered compliance dates contained in the sub-categories for these units as potentially obviating the need for allowance trading, the Proposed Rule assumes that units will necessarily operate right up to their permitted date for their particular sub-category before retiring. However, in today's environment this assumption is no longer valid. The Joint ISOs/RTOs note there are a host of factors that can drive earlier retirement, including market economics, the cost of maintaining the unit, the difficulty in retaining qualified staff for a unit facing a known retirement date, as well the fact that investors will be inclined to take their resources elsewhere rather than continuing to invest capital in a unit with a limited life. In many cases these may be the very units that the ISO/RTO will need to maintain system reliability and critical grid services in this interim period.[25] For these reasons, the EPA's conclusion that the subcategory staggered compliance dates obviate the need for allowance trading is not supported.

Moreover, as the goal should be to control overall sector emissions rather than dictate the controls at each particular unit, the Joint ISOs/RTOs do not find merit in the Preamble's statement that:

> *"An emission trading program that included affected EGUs that have BSERs and resulting standards of performance based on limited expected emission reduction potential---or, in the case of affected EGUs for which states have invoked RULOF, less stringent standards of performance—may introduce the risk of undermining the intended stringency of the BSER for other facilities*."[26]

By the same token, the fact that units may "fall in or out of a trading program from year to year" as a result of the 50% capacity factor that triggers standards of performance, does not "preclude their inclusion in any such program as a practical matter."[27] Rather, allowance trading and the ability to bank allowances can allow units that are on the margin, but are needed by the ISO/RTO, to operate without fear that running above a 50% capacity factor could trigger costly standards of performance. The Joint ISOs/RTOs need the flexibility to call on such units when needed for reliability. Allowance trading will provide added flexibility while a "hard trigger" that pushes a unit into standards of performance in a given year sets up an unnecessary conflict between the GHG rule and the Joint ISOs/RTOs' ability to ensure that the units ISOs and RTOs call upon to ensure reliability will be able to respond.

Although nothing in the Proposed Rule prevents states from proposing allowance trading in their SIPs, an effective allowance trading market requires a common product (*i.e.*, an allowance) that is both liquid and tradable across state lines. As a result, although the Joint ISOs/RTOs endorse the EPA's preliminary conclusion to allow states to propose such programs, the GHG rule does not provide sufficient guidance on how effective interstate trading could be utilized as a compliance strategy.[28] The Joint ISOs/RTOs believe that the considerations that go into choosing a rate-based or mass-based trading system are equally applicable if not even more relevant for interstate trading programs. But

---

[25] To date, RTOs and ISOs have utilized Reliability Must Run Agreements as one tool to maintain those plants during this period. However, that out-of-market solution should be the exception rather than the Rule.
[26] Proposed Rule, 33,394
[27] Proposed Rule, 33,394
[28] Proposed Rule, 33,396

given their interstate nature, the Final Rule needs to provide guidance as to how a proposed interstate trading market can meet EPA's requirements so as to serve as an effective compliance strategy.

On the other hand, the Joint ISOs/RTOs recognize that some states may not prefer to allow units under their jurisdiction to participate in an allowance trading program. These states may want to ensure strict emissions compliance so as to meet individual state goals, which, in some cases, could be stricter than the GHG rule. Accordingly, the Joint ISOs/RTOs propose that the EPA establish clear guidance on the use of allowance trading as an acceptable compliance strategy while making clear that the decision of a particular state to utilize allowance trading as a compliance strategy through their SIP is entirely *voluntary* within that state. In this way, state environmental policies that go beyond the GHG rule could be honored while allowance trading programs could still develop on a national level for those states seeking to opt into such a program.

At the very least, allowance trading would be appropriate among existing units, some of which could over-comply through technology and monetize that over-compliance through trading of allowances to units with higher compliance costs. However, to maximize the benefits of trading and further incentivize new technologies, that trading should not be limited to existing units but should instead allow trading between existing and new units as well. The Joint ISOs/RTOs see nothing in Sections 111(b) and 111(d) that constrains EPA from allowing trading between existing and new units as a compliance strategy.

H. ***Request to Revise the Definition of "System Emergency"***

The Joint ISOs/RTOs generally concur with the definition of "system emergency" detailed in the Proposed Rule with one exception: The Joint ISOs/RTOs recommend that definition of "system emergency" be revised by striking the term "abnormal" as shown below:

> *"Any ~~abnormal~~ system condition that the RTO, Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load."*

The system operator is required to call system emergencies only during defined events as specified in its Tariffs or rules and in NERC's Reliability Standard EOP-011-01.[29] The Joint ISOs/RTOs submit that the use of the word "abnormal" is unnecessary because the definition already requires that the grid operator must determine the generator is necessary to operate to ensure grid reliability. To avoid creating confusion about whether a given grid condition may be considered "abnormal," and because the protocol for declaring system emergencies is transparent and well-defined, the word "abnormal" should be stricken.

CONCLUSION

[29] NERC Reliability Standard EOP-011-01

The Joint ISOs/RTOs note that this short Comment Period and the lack of dialogue on these specific issues leading up to the Proposed Rule have made it difficult for the Joint ISOs/RTOs to undertake the full analysis of reliability impacts that a Rule of this magnitude should include. It is for this reason that the Joint ISOs/RTOs urge that the EPA refrain from adopting the Final Rule for a sufficient but finite time to allow for a more thorough exploration of the reliability impacts of the proposed Rule and its impact on investment decisions, and to discuss these conclusions with the ISOs/RTOs.

Should the EPA nevertheless wish to proceed on its accelerated timeline, the Joint ISOs/RTOs urge consideration of including in the Final Rule the tools outlined herein to allow for mitigation of some of these impacts.

In either instance, the Joint ISOs/RTOs look forward to continuing their constructive dialogue with the EPA as it proceeds to the next step in this process. We appreciate our past work with EPA and stand ready to work constructively to address the reliability issues surrounding the Proposed Rule as well.

Respectfully submitted,

/s/ Timothy Caister
Timothy Caister
Deputy General Counsel-Tariff & Policy Transformation
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, Indiana 46032
Telephone: (317) 249-5400
tcaister@misoenergy.org

/s/ Craig Glazer
Craig Glazer
Vice President-Federal Government Policy
M. Gary Helm
Sr. Lead Energy & Environmental Strategist
Natalie Tacka Furtaw
Sr. Engineer II
Thomas DeVita
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
Ph: (610) 666-8248
Fax: (610) 666-8211
craig.glazer@pjm.com
gary.helm@pjm.com
natalie.furtaw@pjm.com
thomas.devita@pjm.com

/s/ Chad V. Seely
Chad V. Seely
Senior Vice President & General Counsel
Nathan Bigbee
Deputy General Counsel
Katherine Gross
Senior Corporate Counsel
Electric Reliability Council of Texas, Inc.
8000 Metropolis Drive, Bldg. E, Suite 100
Austin, Texas 78744
chad.seely@ercot.com

/s/ Paul Suskie
Paul Suskie
Executive Vice President & General Counsel
Lanny Nickell
Chief Operating Officer
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, Arkansas 72223-4936
(501) 614-3232
psuskie@spp.org
lnickell@spp.org

Dated: August 8, 2023

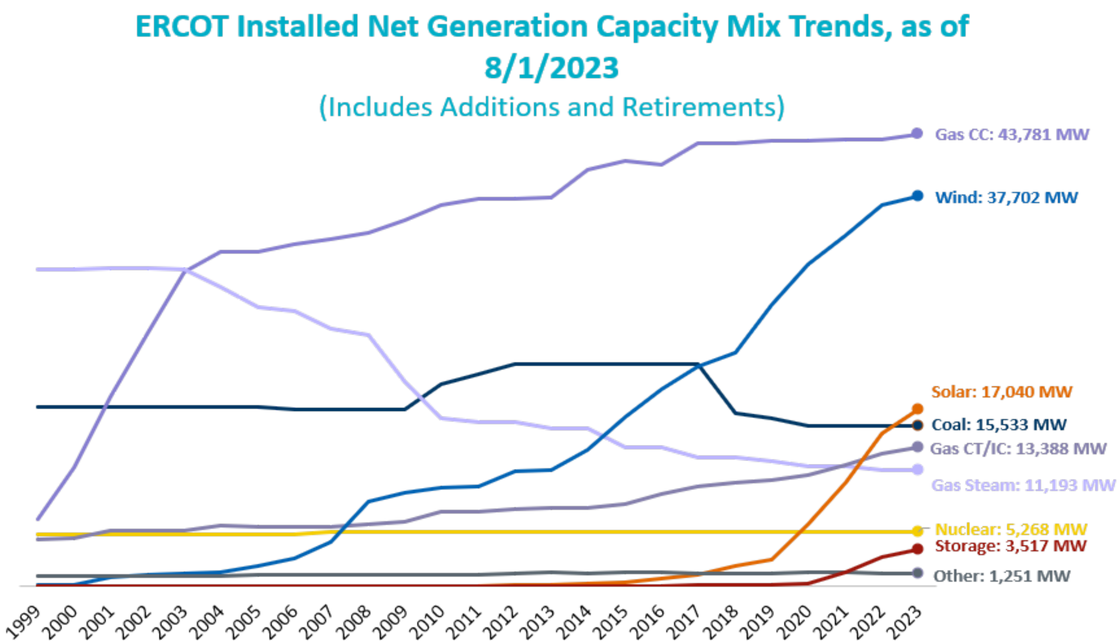
cc: Joseph Goffman, Principal Deputy Assistant Administrator

Christian Fellner, Sector Policies and Programs Division, OAQPS

Lisa Thompson, Sector Policies and Programs Division, OAQPS

APPENDIX 1

ERCOT



Notes: Capacity totals are based on the Installed Capacity Ratings for generating units. "Other" comprises of Biomass, Hydro, and Diesel.
- Planned generation projects are added to installed capacity after approval for synchronization to ERCOT Grid.
- Totals include Private-Use Network generators that export to the ERCOT grid, Distribution Generation Resources (DGRs), Settlement-Only Distribution Generators (SODGs), Unavailable Switchable Capacity, Extended Outage Units, and Mothballed Units.

APPENDIX 2

MISO

MISO's Response to the Reliability Imperative

The Reliability Imperative is the term MISO uses to describe the shared responsibility that MISO, its members, and states have to address the urgent and complex challenges to electric system reliability in the MISO region. MISO's response to the Reliability Imperative consists of a host of interconnected initiatives that address the region's challenges in a comprehensive and prioritized fashion. These initiatives are described in a "living" report located on MISO's public website here: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-reliability-imperative/

The following is an excerpt from the Reliability Imperative report:

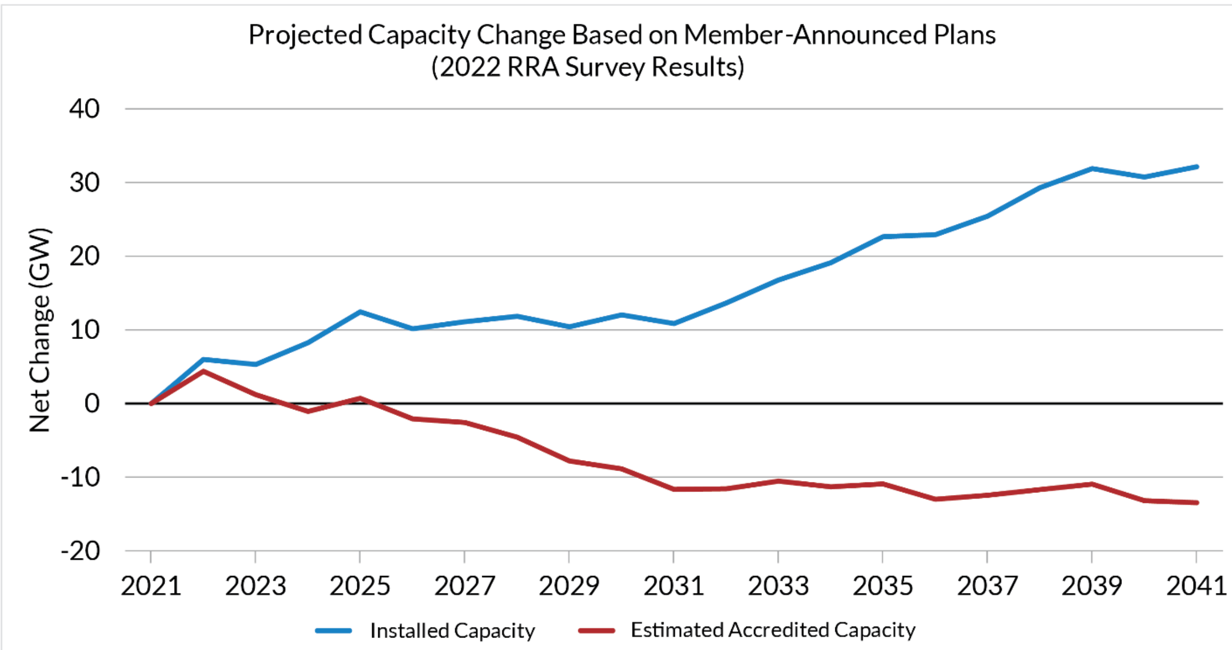
Many MISO members and states have set ambitious goals to partially or fully decarbonize their fleets of generating resources by future target dates. To be sure, utilities, states, and MISO must consider what the system will look like and how it will operate at the eventual "end state" of the decarbonization efforts that are playing out across the region. However, we must first ensure that the system remains reliable and affordable *during the transition* to that end state—and the rapid transition of the region's fleet of generating resources is giving rise to a host of urgent and complex reliability challenges. These challenges include:

- The region's level of "accredited" generation capacity is declining because the new resources that are being built—primarily wind and solar—have lower accreditation values than the conventional thermal resources that are retiring. The resulting lower reserve margins mean the region has fewer reserve resources to call on in emergencies or other tight grid conditions.
- Aging conventional resources that remain in service can be more prone to outages, potentially rendering them unavailable when they are needed most.
- Wind and solar resources are not always available during times of need due to their intermittent, weather-dependent nature.
- Due to the region's projected increasing reliance on solar generation, the system's need for controllable resources that can rapidly ramp up their output when solar becomes unavailable could triple by 2031 and quadruple by 2041 compared to current levels.
- Some fast-ramping resources may be critically needed going forward to back up intermittent renewables, but because they may not run very often, there may be little economic incentive for utilities and states to build new resources of this type, or to keep existing resources with these attributes in service.
- The region is becoming increasingly reliant on Load Modifying Resources that MISO can currently only access by engaging its emergency operating procedures.
- Distribution-level and behind-the-meter resources are becoming more prevalent, yet MISO does not yet have visibility into how these resources may affect the larger grid system.

MISO's Regional Resource Assessment (RRA): The RRA is a recurring study based on the plans and goals that MISO members have publicly announced for their generation resources. The RRA aggregates these plans and goals and uses them to develop an indicative view of how the region's resource mix might evolve going forward. The RRA is located on MISO's public website here: https://www.misoenergy.org/planning/policy-studies/RRA/#t=10&p=0&s=FileName&sd=desc

The key insights from the 2022 RRA are as follows:

KEY INSIGHT 1: The 2022 snapshot of MISO member plans indicates an increase in the overall amount of installed capacity, but a decline in accredited capacity compared to current levels.



KEY INSIGHT 2: The RRA modeling indicates a continued near-term capacity risk, highlighting the urgent need for coordinated resource planning and additional investment.

KEY INSIGHT 3: Wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80% relative to 2005 levels but also sharply increase the complexity of reliably operating and planning the system.

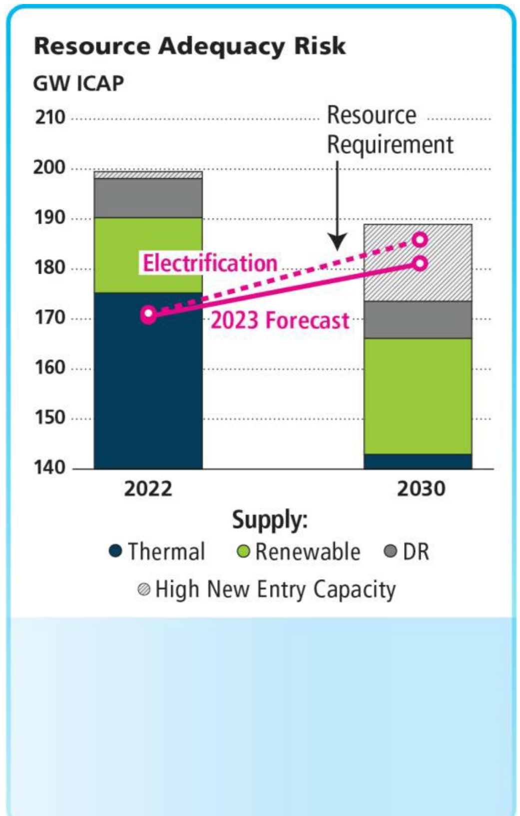
KEY INSIGHT 4: As the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps increase by three times by 2031 and four times by 2041 compared to current levels.

KEY INSIGHT 5: The capacity contribution of solar generation is forecast to decline rapidly as more solar capacity is added to the system, impacting the region's overall capacity outlook. The contribution of wind generation remains relatively stable as more wind capacity is added.

APPENDIX 3

PJM

PJM is undertaking efforts aimed at maintaining reliability during the energy transition. Ensuring a Reliable Energy Transition details PJM's efforts to identify challenges and solutions to maintaining reliability as the bulk power grid evolves into a system deriving most of its energy from low-carbon resources. Near- and medium-term challenges have been identified in a series of reports PJM has released, entitled *Energy Transition in PJM*. The most recent edition, Resource Retirements, Replacements and Risks, indicates that it is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. The report describes 40 GW of dispatchable generation at-risk for retirement by 2030, approximately 21% of PJM's installed capacity.



These potential retirements coupled with low new resource entry risks reducing capacity reserve margins below required levels near the latter part of this decade, largely due to policy driven retirements, and prior to accounting for the impacts of the Proposed Rule (see Table 1 below). The Proposed Rule puts an additional 15 GW of coal at-risk in PJM, pushing at-risk generation to 29% of installed capacity. An additional 22% of PJM's installed capacity, the most-efficient, dispatchable gas-fired generation will be forced to undertake expensive control options or significantly reduce operations under the Proposed Rule. Recent analysis by S&P Global[30] on the Proposed Rule finds that the cost to retrofit CCS on coal units will drive most to retire, creating a firm capacity gap and heightening the need for replacement capacity with the appropriate characteristics and capabilities.

[30] "EPA's proposed power plant rule to accelerate coal retirements —but what about gas?", P. Luckow & M. Lester, Aug 2, 2023, S&P Global Commodity Insights (subscription)

Table 1. Reserve Margin Projections Under Study Scenarios

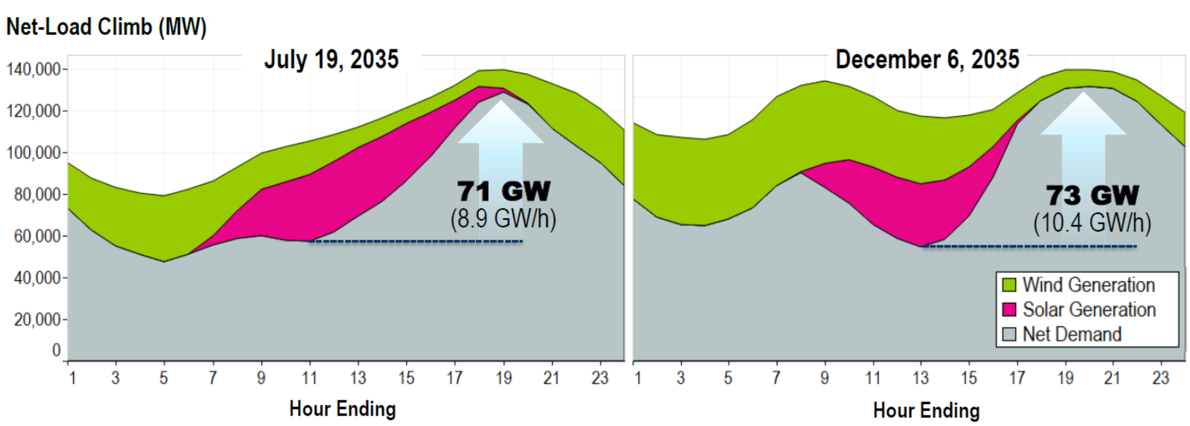
Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

PJM's first report in the Energy Transition in PJM series: Frameworks for Analysis [31] found, among other things, that:

> *Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability. PJM and stakeholders must ensure that the market structure provides the right incentives to maintain an adequate supply of these services.*

PJM's second report in the Energy Transition in PJM series: Emerging Characteristics of a Decarbonizing Grid documented the need for additional ramping capability as intermittent resources increase (See Figure below).[32] This important operational flexibility is provided by mainly by thermal resources, but will be complemented by storage resources as they grow in duration and total capacity. This also reinforces the need to maintain thermal resources until substitutes are available at scale.

Figure 17. Total Climb From Beginning to End of the Ramping Period for Selected Summer and Winter Days



PJM also continues to monitor and anticipate the need for essential reliability services, and encourage the development of new technologies with the capabilities to provide those services. This builds on previous studies[33], including those cited above.

---

31 Energy Transition in PJM: Frameworks for Analysis

32 Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid

33 Reliability in PJM: Today and Tomorrow

From a regional transmission planning perspective, PJM's Grid of the Future report details continuing efforts to enhance planning processes to address key trends driving future grid expansion.[34]

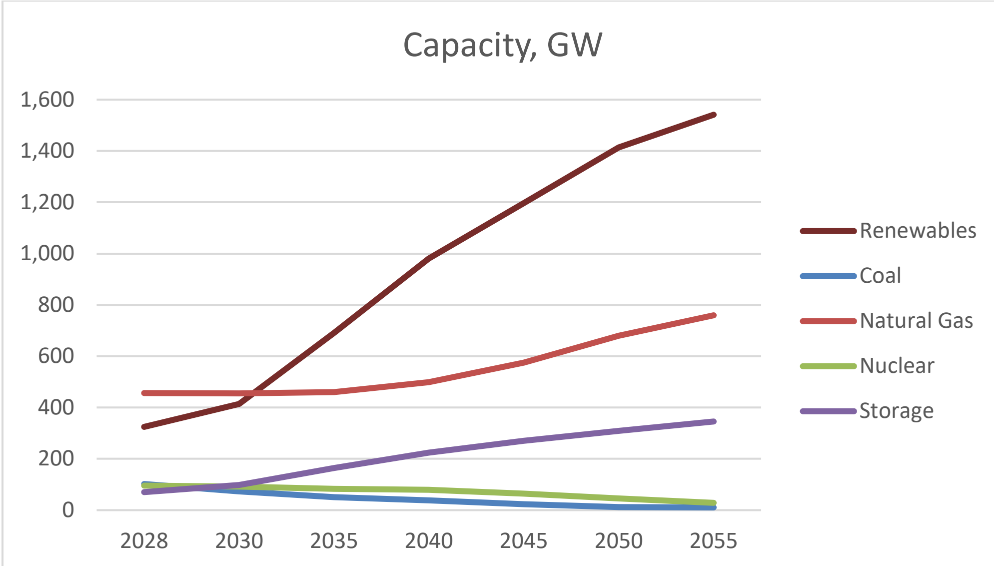
PJM and its stakeholders are working to retain the needed resources; however, maintaining reliability is a shared responsibility, which points to the importance of incorporating all aspects of reliability when regulating thermal resources. Grid reliability needs to consider policies that are increasing, or are expected to increase, electrification and dependency on the electric grid. Policies that accelerate building[35], vehicle[36] and industrial[37] electrification are increasing load growth at the same time current EPA regulations and proposals are targeting resources needed to maintain reliability.

NERC's latest Long Term Reliability Assessment[38] also addressed concerns regarding regulatory and policy related retirements, containing the following recommendations:

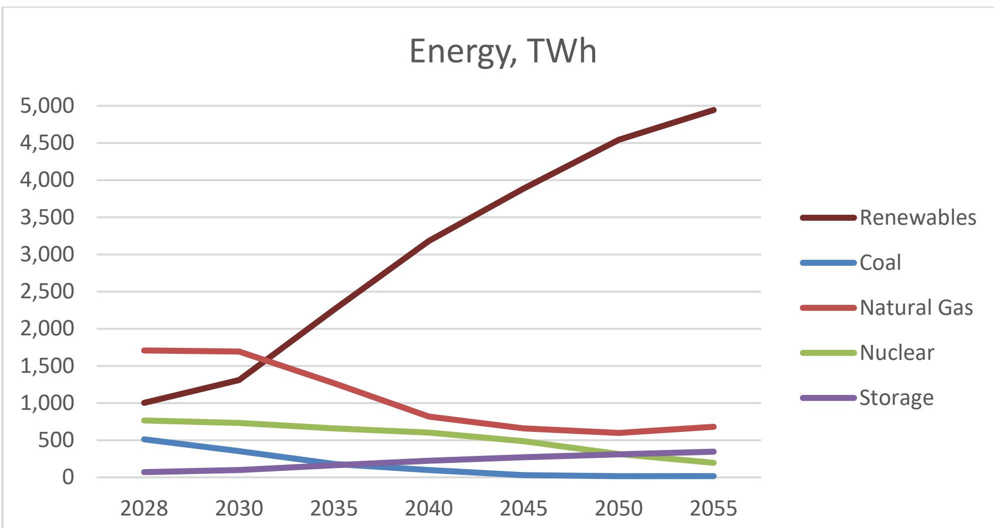
> State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks.
>
> Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.

PJM also reviewed the modeling EPA conducted for the Proposed Rule, which reinforced our concerns regarding EPA basing their assessment of reliability impacts on projections of modeled outcomes of the Inflation Reduction Act, in particular meeting the significant new builds of renewables and energy storage and the resultant energy projections (see Figures below). This modeling of the IRA build out reflects an assumption common in modeling that "investors and lenders take advantage of subsidies in an optimized world in which economic incentives are the sole drivers of change."[39] IPM documentation states: "IPM's objective function is to minimize the total, discounted net present value of the costs of meeting demand, power operation constraints, and environmental regulations over the entire planning horizon."[40] Additionally, that "the tax credits for new renewable technology investments provided under the Inflation Reduction Act of 2022 are implemented in EPA Platform v6 as a reduction to capital costs."[41] EPA acknowledges that "additional effects of the IRA beyond those modeled in this RIA could result in a change in projected system compliance costs and emissions outcomes."[42]

[34] Grid of the Future: PJM's Regional Planning Perspective
[35] Federal Building Performance Standard
[36] Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles
[37] DOE Industrial Decarbonization Roadmap.
[38] NERC, 2022 Long Term Reliability Assessment, December 2022,
[39] Growing Pains: The Renewable Transition in Adolescence, M. Cembalest, March 28, 2023, p.11.
[40] EPA Platform v6 – Post IRA 2022 Reference Case, Chapter 2: Modeling Framework.
[41] EPA Platform v6 – Post IRA 2022 Reference Case, Chapter 4: Generating Resources.
[42] EPA Regulatory Impact Analysis.



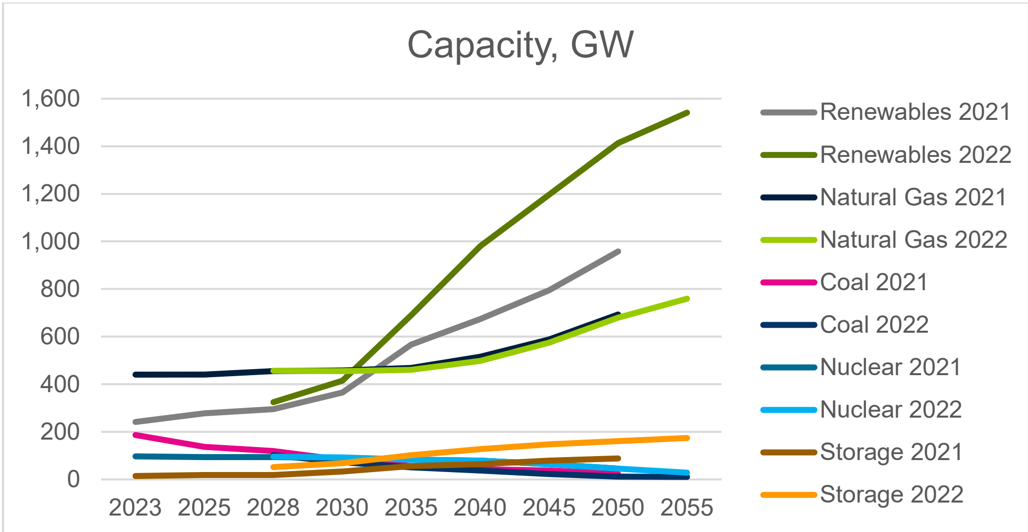
Total Capacity (Cumulative GW) from *IPM-EPA Updated Baseline with LNG Update*.[43]



Total Energy (Cumulative TWh) from *IPM-EPA Updated Baseline with LNG Update*.[44]

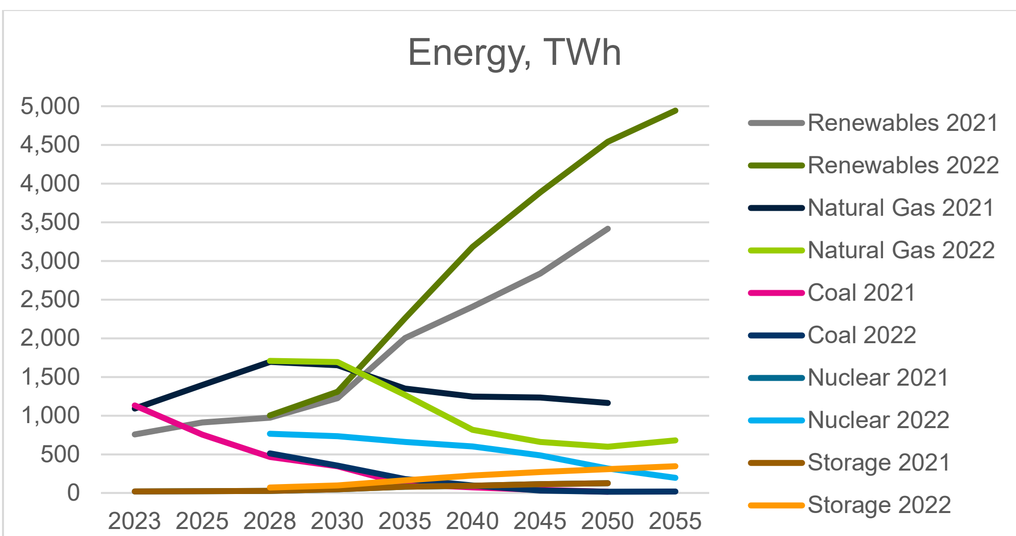
The Figure below shows a comparison of projected generation capacity results from EPA modeling the IRA using EPA's Power Sector Modeling Platform v6 based on IPM Summer 2021 Reference Case versus the 2022 Post-IRA Reference Case. This is helpful in showing how the modeling effort

[43] EPA Updated Baseline with LNG Update, July 7, 2023.
[44] Same citation as above



Comparison of Good Neighbor Rule + IRA[45] to GHG NSPS Updated Baseline with LNG Update

progressed, as well as providing a starting point in 2023 rather than 2028, enabling the visualization of the projected impacts from a point closer to today. The comparison shows a significant change (increase) in renewable capacity, as well as a noticeable change (increase) in storage capacity between the models, while not showing similar changes in coal, natural gas or nuclear capacity between models. Similarly, comparing the projected energy output results of the two models (in Figure below) shows a significant change (increase) in renewable energy, a noticeable change (increase) in storage energy, and a significant change (decrease) in natural gas energy, while not showing any change in coal or nuclear. This again points to the inherent difficulties in modeling the IRA and subsequently basing reliability assessments of the Proposed Rule on those projected results.



Comparison of Good Neighbor Rule + IRA[46] to GHG NSPS Updated Baseline with LNG Update

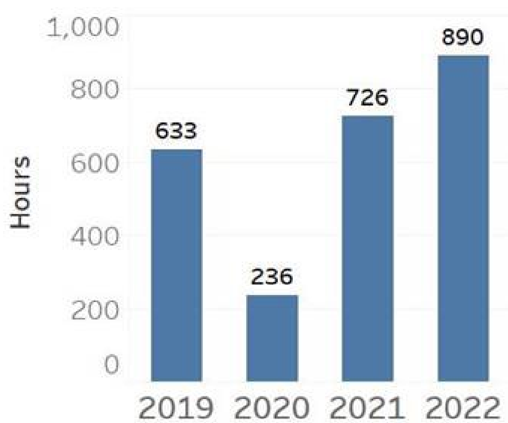
45 Sensitivity Final Rule + IRA.
46 Sensitivity Final Rule + IRA.

APPENDIX 4

SPP

SPP has adapted its market design, operations processes, and transmission planning practices to keep pace with the changing resource fleet thus far. However, since 2014, SPP has experienced the retirement of over 7,600 MW of thermal resources. SPP saw over 2,796 MWs of thermal generation retire from 2019 to 2022, and SPP has already seen an additional 809 MW retire thus far in 2023. As the thermal fleet shrinks without comparable replacement in fuel-assured, ramp-able capacity, the remaining fleet carries the additional burden the recently retired resources provided. This additional stress has led to more planned and forced outage rates, particularly with an aging fleet of such resources. Some resources are being forced to take maintenance outages during summer and winter conditions.

These retirements have also contributed to declining reserve margins. SPP has recently seen an increase in levels of system alerts as the remaining thermal fleet is increasingly stressed by managing typical load fluctuations. As illustrated below, from 2019 to 2022, SPP experienced over 2,475 hours of system alerts, including 33 hours of Energy Emergency Alerts. In 2022, SPP experienced 257 more alert hours than it did in 2019, which amounts to almost eleven days.



The graph below illustrates that SPP has determined that with a mere 3% increase of historical gross load, the region's conventional resources serving net load (gross load minus wind and solar output)[47] have no margin for additional retirements.

[47] Impacts from Winter Storm Uri were not included in this analysis.

Please note loads are projected to be higher than 3% on average due to general load growth, electrification, electric vehicle charging, hydrolyzers, crypto-mining, data centers, and micro-grids (when they are grid-served). In an effort to facilitate an orderly transition that ensures the reliability levels the region has enjoyed for decades, it is imperative resources do not accelerate retirement until there are adequate replacements.

SPP establishes a Planning Reserve Margin ("PRM") requirement designed to ensure that SPP will have sufficient capacity to serve peak demand obligations. The current PRM requirement of 15% was determined in accordance with SPP's tariff, which directs SPP to conduct an LOLE study and set a PRM value to maintain a loss of load value equal to or less than one day in ten years. That PRM requirement is subject to change and may need to be increased in future years as the transition to a less-dispatchable resource mix continues.

SPP planning staff has analyzed projected capacity levels as reported by its LREs and has issued a five-year outlook for the SPP Balancing Authority Area.[48] The current reported PRM for the 2023 summer season is 20.1%, which is above the current PRM requirement of 15%. However, the combined impacts of decreasing resource capacity and increasing demand by current projections would lead to a significant decrease in the PRM over the next five years. As reflected in the graph below, the projected margin will barely exceed the current PRM requirement by 2026. If the projection were to hold true, it will fall below the requirement in 2027, and it will continue to drop to 9.7% by 2028. Of course, the current 15% PRM requirement and any future established PRM requirements must be maintained by the Load Responsible Entities in SPP. However, such requirements and penalties for not maintaining the required PRM cannot override a mandate from this Proposed Rule. Once the reserve margin has fallen below

[48] *See* the 2023 SPP June Resource Adequacy Report at: https://www.spp.org/documents/69529/2023%20spp%20june%20resource%20adequacy%20report.pdf

the 15% PRM requirement, SPP would no longer be able to meet the industry standard for loss of load of one day in ten years.

STATE OF NORTH DAKOTA
OFFICE OF ATTORNEY GENERAL
www.attorneygeneral.nd.gov
(701) 328-2210

Drew H. Wrigley
ATTORNEY GENERAL

CIVIL LITIGATION
NATURAL RESOURCES AND
NATIVE AMERICAN AFFAIRS
500 NORTH 9TH STREET
BISMARCK, ND 58501-4509
(701) 328-3640 FAX (701) 328-4300

August 8, 2023

Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460
https://www.regulations.gov

Attn: Docket ID No. EPA–HQ–OAR– 2023–0072

RE: EPA's Proposed Rule: New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule ("Proposed Rule")

Dear Administrator Regan,

On May 23, 2023, the U.S. Environmental Protection Agency ("EPA") published the above-noted Proposed Rule in 88 Fed. Reg. 33,240. The State of North Dakota ("North Dakota" or the "State") respectfully submits these comments in response to the Proposed Rule. For the reasons explained in these comments, EPA must withdraw the Proposed Rule due to the significant legal and technical deficiencies associated with the Proposed Rule.

I. INTRODUCTION

As a major energy producing state (from significant lignite coal, oil, natural gas, hydro and wind resources), North Dakota has an unmistakable sovereign interest in regulating the responsible development of its natural resources and their use. In fact, the North Dakota Legislature ("Legislature") has long declared it to be an essential government function and public purpose to foster and encourage the wise use and development of North Dakota's vast lignite coal resources to maintain and enhance the economic and general welfare of North Dakota.[1]

EPA's Proposed Rule would require North Dakota to submit a plan to EPA to reduce its carbon dioxide ("CO_2") emissions, making retirement of its fleet of lignite fueled power plants "federally enforceable" unless the plants elect to commit to certain conditions. Those conditions would result in a dramatic and immediate shift away from lignite coal-powered electric generating plants in favor of gas-powered plants or renewable sources.

Indeed, according to EPA's own modeling, the Proposed Rule will lead to the closure of specific lignite coal-fueled electric generating plants. These closures would disproportionately harm North Dakota, as North Dakota has the largest known deposits of lignite coal in the world[2] and most of the coal mines in the State are lignite mines. The Proposed Rule would therefore not only deny North Dakota its sovereign authority to administer energy and environmental policies within its

[1] North Dakota Century Code ("N.D.C.C.") § 54-17.5-01.
[2] North Dakota State Profile and Energy Estimates, Energy Information Administration (available at: https://www.eia.gov/state/?sid=ND#tabs-1 (last visited August 8, 2023))

borders, but would also deprive North Dakota of a substantial amount of tax and coal royalty payments, which can never be recovered.

The Proposed Rule would dictate North Dakota's energy policy, contrary to North Dakota's extensive and longstanding statutory support for lignite coal-fueled electricity. EPA's Proposed Rule would usurp the authority and discretion of North Dakota and its respective agencies responsible for implementing environmental and energy policy.

The Proposed Rule would also have profound adverse impacts on North Dakota and the upper Midwest region's electric power sector and, in effect, redefine how electricity is generated and delivered through the electric power grids in these areas.

The Proposed Rule is an affront to North Dakota's sovereign interests in the continued use of its lignite coal resources to generate electricity and the state's past and ongoing significant investment in the development and implementation of technologies aimed at successfully capturing and geologically storing carbon emissions in North Dakota.

As the United States Supreme Court ("Supreme Court") recognized in *Massachusetts v. EPA*,[3] a federal agency can only exercise the authority Congress has delegated to it. Consistent with this precedent, on June 30, 2022, the Supreme Court issued its long-awaited decision in *West Virginia et al. v. EPA*,[4] where it held that EPA exceeded the authority granted to it by Congress when EPA imposed greenhouse gas emissions ("GHG") limits on existing coal-fueled power plants that could not be achieved in order to force States and energy producers to shift generation to sources that emit fewer GHG emissions.

North Dakota's independent participation in *West Virginia et al.* emphasized the fact that Congress gave the States a primary role in regulating air emissions from existing power plants and that EPA cannot unilaterally impose major national requirements that cut States out of the process. On October 29, 2021, the Supreme Court granted North Dakota's petition for *certiorari*, along with those of three other petitioners (West Virginia, North American Coal Corporation, and Westmoreland Mining Company). The Supreme Court's *West Virginia et al.* decision was not its first consideration of EPA's Clean Power Plan ("CPP"). Notably in 2016, the Supreme Court granted North Dakota and four other parties' applications to stay implementation of the CPP.

Now, shortly over a year after the Supreme Court's decision in *West Virginia et al.*, EPA is back with a flurry of proposed federal rules aimed at eliminating coal-based electric generating facilities. EPA not only lacks the legal authority to take such actions, but it is also sadly making a mockery of the Clear Air Act ("CAA") and the state-federal "partnership" which Congress called for thereunder. Worse, EPA is also making a mockery of the Supreme Court's decisions in *West Virginia et al.* North Dakota cannot stand for either course of EPA conduct.

II. EPA'S USE OF SUBCATEGORIZATION IN THE PROPOSED RULE IS NOT CONSISTENT WITH EPA'S LAWFUL AUTHORITY UNDER THE CAA

In the Proposed Rule, EPA has proposed four subcategories for existing coal-fueled electric generating units ("EGUs") and assigned a best system of emissions reduction ("BSER") for each subcategory. The subcategories each have a federally enforceable retirement date that EGUs may opt-in to or be assigned to if they already are subject to such a date. The resulting groups of EGUs in each category will have widely disparate characteristics such as age, generating capacity, and

[3] *See* 549 U.S. 497, 534-35 (2007) (noting that EPA must "ground its reasons for action or inaction in the statute" and "exercise its discretion within defined statutory limits.").
[4] 142 S. Ct. 2587 (2022).

the other physical characteristics that usually accompany subcategorization under Section 111(b)(2).[5]

EPA will not know the identities or characteristics of units in each subcategory until after North Dakota's State Implementation Plan ("SIP") has been submitted to EPA. All units in each subcategory must comply with their respective emission limitations by January 1, 2030. North Dakota and other States must submit their SIPs to EPA within two years following issuance of a final rule - meaning that sources without federally enforceable retirement dates will need to decide their remaining operating lifetimes within the 2024-26 period. The four BSER subcategories are:

1) Units that commit to retire before 2032 are subject to a unit-specific performance standard (lbs CO_2/MWh) based on routine operation and maintenance ("O&M") with no increase in their CO_2 emissions rate;

2) Units that commit to retire before 2035 and limit operation to a 20% capacity factor are subject to a performance standard based on routine O&M with no increase in their CO_2 emission rate;

3) Units that commit to retire before 2040 are subject to a performance standard based on co-firing with 40% natural gas;

4) Units that retire 2040 or later are subject to a performance standard based on 90% CO_2 capture with carbon capture and sequestration/storage ("CCS").

CAA Section 111(b)(2) (source subcategorization) does not authorize EPA to subcategorize affected EGUs without knowing the characteristics of the facilities that would fall into the subcategory. Rather, Section 111(b)(2) allows EPA to subcategorize the EGU source category by physical characteristics, specifically "classes, types, and sizes within categories" for the purpose of setting performance standards under CAA Section 111.[6] As a result, EPA does not have the authority under the CAA to establish unpopulated subcategories of affected coal-fired EGUs that would be populated only if a unit elected to retire by a specific date (such as 2032, 2035, or 2040). Rather than addressing unit retirement as a subcategorization issue in Section 111(b)(2), Congress directed EPA in Section 111(d)[7] to allow the States to take "remaining useful life" into account in setting source-specific performance standards. The arbitrary retirement dates chosen by EPA may or may not correlate with the remaining useful life of North Dakota EGUs that EPA included within each subcategory of the Proposed Rule.

EPA's proposed approach for subcategorization conflicts with the CAA. Specifically, it fails to differentiate among coal-fired units within the EGU source category in accordance with the statutory criteria, such as the size of the unit, the type of coal combusted, the boiler technology used for combusting the coal, other physical attributes of the generating facility, or how it is operated (such as the unit's capacity factor).[8] Rather, EPA has lumped all classes, types, and sizes of coal-fired units together and then divided them into four proposed subcategories based on federally enforceable retirement dates. EPA then applied a presumptive BSER to each

[5] 42 U.S.C. § 7411(b)(2).
[6] 42 U.S.C. § 7411.
[7] 42 U.S.C. § 7411(d).
[8] North Dakota's Fort Union lignite-fueled EGUs are primary and longstanding examples of EPA's proper use of subcategorization under CAA Section 111(b)(2). That EPA now arbitrarily proposes to remove this longstanding subcategorization for Fort Union lignite (which North Dakota vehemently opposes) does not change this circumstance. *See* EPA-HQ-OAR-2018-0794, Comments of State of North Dakota and Comments of the North Dakota Coal Conversion Counties Association ("CCCA"). North Dakota incorporates both referenced comment letter documents into its comments herein.

subcategory without knowing in advance any of the physical characteristics of units that may be included in each subcategory.

III. THE PROPOSED RULE EXCEEDS EPA'S STATUTORY AUTHORITY AND VIOLATES THE COOPERATIVE FEDERALISM MANDATED BY THE CAA

EPA has claimed the BSER is based on four EGU requirement groupings and demands the States implement and achieve in order to have an "approvable" State plan. EPA's dictat violates Section 111 of the CAA and the cooperative federalism enshrined in the CAA by Congress.

The primary regulatory authority for setting standards of performance for specific individual existing sources in North Dakota is the North Dakota Department of Environmental Quality ("NDDEQ"). The BSER emission guidelines under Section 111(d) are supposed to act as national "guardrails" within which the States exercise their authority to set the actual specific emission limits. EPA does not have the authority to establish nationwide mandatory emission limitations masquerading as "BSER" and force North Dakota to adopt them.

CAA Section 111(b)(2) does not authorize EPA to subcategorize North Dakota EGUs by retirement dates. Rather, Section 111(b)(2) allows EPA to subcategorize by physical characteristics, specifically "classes, types, and sizes within categories" for the purpose of setting performance standards under CAA Section 111. As a result, EPA lacks CAA authority to set different standards based on whether an affected lignite-fired EGU will retire by a specific date (such as 2032, 2035, or 2040) or whether that EGU may elect to limit its annual capacity factor to 20%.

The proposed 20% capacity factor subcategory for EGUs retiring between 2032 and 2035 and the proposed 40% co-firing with natural gas subcategory for EGUs retiring between 2035 and 2040 are simply an EPA attempt at mandating fuel-switching because dramatically reduced utilization and co-firing will certainly force generation shifting. EPA lacks authority to offer these conditions in exchange for a later retirement date.

The Proposed Rule also incorrectly asserts that CCS "has been adequately demonstrated" at commercial scale EGUs in the United States. With the agency's reliance on *Portland Cement Ass'n* v. *Ruckelshaus*[9] – a CAA Section 111(b) new source case – in a Section 111(d) rulemaking for existing sources. EPA even acknowledges that coal-fired EGUs subject to a 2030 retirement deadline would not have time to wait for SIP approvals before having to finance, permit, and construct a CCS facility including all its ancillary equipment, such as pipelines and underground storage capacity.

A. Reduced Utilization with 2035 Retirement

EPA's proposed guidelines impose a 2035 retirement date if an EGU owner agrees to limit its capacity to 20% through reduced utilization. The average capacity factor of coal units in 2021 was 49% according to EPA[10] with 67% of units being larger than 500 megawatts ("MW")[11].

The Supreme Court's decision in *West Virginia et al.* rejecting the CPP bars generation shifting as a means to reduce CO_2 emissions.[12] Notably, EPA's CPP identified reduced utilization and generation shifting as key means for sources to comply with the building blocks in that rule:

---

[9] 486 F.2d 375, 391 (D.C. Cir. 1973).

[10] 88 *Fed. Reg.* 33240, 33257.

[11] 88 *Fed. Reg.* 33240, 33258.

[12] The Court noted: "The Government attempts to downplay matters, noting that the Agency must limit the magnitude of generation shift it demands to a level that will not be 'exorbitantly costly' or 'threaten the reliability of

> EGUs have a long history of reducing their generation and either replacing it directly or having it replaced through the operation of the interconnected electricity system through measures similar to those in building blocks 2 and 3. Thus, an EGU can either directly replace its generation, or simply reduce its generation, and in the latter case, the integrated grid, combined with the high degree of planning and various reliability safeguards, will result in entities providing replacement generation. This means that consumers receive exactly the same amount of the same product, electricity, after the reduced generation that they received before it.[13]

The Proposed Rule contains a BSER framework that initiates the same generation shifting that the Supreme Court rejected in *West Virginia et al.*

On July 7, 2023, EPA released updated IPM modeling for the Proposed Rule considering higher projected liquified natural gas and natural gas prices.[14] The updated modeling underscores the extent of EPA's premature coal retirements projected under the Proposed Rule:

> Under the integrated proposal modeling, 44 [gigawatt] GW of coal-fired EGUs have committed retirements by 2035 and operate at an annual capacity factor of 20 percent or less in 2030, and as such are subject to the near-term existing coal-fired steam generating units subcategory. By 2040, 1 GW of coal-fired EGU capacity has committed to retirement and is subject to the 40 percent natural gas co-firing requirement. 12 GW of coal-fired EGUs that plan to operate past 2040 are subject to the long-term existing coal-fired steam generating unit subcategory and, as such, install CCS (reflecting 3 GW incremental to the updated baseline). Finally, 21 GW of coal-fired EGUs undertake coal to gas conversion (9 GW incremental to the updated baseline).
>
> Under the updated baseline, total coal retirements between 2023 and 2035 are projected to be 104 GW (or 15 GW annually). Under the proposed rules, total coal retirements between 2023 and 2035 are projected to be 126 GW (or 18 GW annually). This is in comparison to an average historical retirement rate of 11 GW per year from 2015 – 2020.[15]

The accelerated pace of retirements under the Proposed Rule will force generation shifting from coal to other energy sources. The Proposed Rule will lead to a number of premature retirements which will result in North Dakota losing grid reliability as baseload and dispatchable generating sources like lignite coal-fueled electrical generators are forced out.

B. Natural Gas Co-firing

EPA's proposed third subcategory covers EGUs that commit to retiring before 2040 that will be subject to a performance standard commencing January 1, 2030, based on 40% co-firing of natural gas. This level of co-firing is excessive both in terms of the cost of natural gas and technical constraints associated with combusting such a large volume of gas in lignite coal-fueled boilers.

---

the grid.' Brief for Federal Respondents 42. This argument does not limit the breadth of EPA's claimed authority so much as reveal it: On EPA's view of Section 111(d), Congress implicitly tasked it, and it alone, with balancing the many vital considerations of national policy implicated in the basic regulation of how Americans get their energy. There is little reason to think Congress did so." *West Virginia et al.*, 142 S. Ct. at 2596.

[13] 80 *Fed. Reg.* 64662, 64782 (October 23, 2015).

[14] EPA-HQ-OAR-2023-0072-0237, EPA, "INTEGRATED PROPOSAL MODELING AND UPDATED BASELINE ANALYSIS," Memo to the Docket, July 7, 2023, https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf

[15] *Id.* at 16 (footnote omitted).

Regardless, for the reasons noted below, EPA lacks authority under Section 111(d) of the CAA to require fuel-switching at such facilities.

C. EPA's Proposed Rule would deprive North Dakota of its authority and discretion to control emissions through a State plan and is, therefore, unlawful under CAA Section 111(d)

Described as an "experiment in federalism,"[16] the CAA assigns the States the primary role in air pollution prevention and control. One of the States' principal authorities and responsibilities under the CAA is to implement and enforce standards of performance for existing sources of air pollution under Section 111(d) using the States' expertise in applying source-specific considerations and factors to establish achievable emission limitations controlling air emissions from those sources.

To that end, Section 111(d) directs EPA's Administrator to "prescribe regulations which shall establish a procedure . . . under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant . . . and (B) provides for the implementation and enforcement of such standards of performance."[17] This text reflects the Federal-State balance of the cooperative federalism framework created by Congress: EPA is to establish national guidelines (i.e., BSER) for the States to follow in creating their Section 111(d) plans. And it is the States, through the States' plans, that establish the specific standards of performance (i.e., achievable emission limitations) for the existing sources in their State.

The primary "regulatory authority" and decisionmaker in setting standards of performance for specific individual existing sources under Section 111(d) is therefore the State. Section 111(d) does not grant EPA the authority to establish nationwide mandatory emission limitations, such as the presumptive and fixed standards of performance masquerading as BSER in the Proposed Rule, and force the States to achieve these emission limitations through the State plans. This deprives States of their authority expressly protected under Section 111(d), reducing the States' roles to mere extensions of Federal authority.

EPA wrongly justifies its unlawful extension of its authority by claiming that in *West Virginia et al.* "[t]he Supreme Court made clear that CAA Section 111 authorizes the EPA to determine the BSER and the amount of emission limitation that state plans must achieve."[18] In fact, the Supreme Court in *West Virginia et al.* gave no such blessing for EPA to set a BSER that operates as a presumptive national standard of performance, imposing binding emission limitations on the States:

> "We have no occasion to decide whether the statutory phrase "system of emission reduction" refers exclusively to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as the BSER. To be sure, it is pertinent to our analysis that EPA has acted consistent with such a limitation [*e.g.* only choosing BSER measures that could be applied at individual sources] for the first four decades of the statute's existence. But the only interpretive question before us, and the only one we answer, is more narrow: whether the "best system of emission reduction" identified by EPA in the Clean Power Plan was within the authority granted to the Agency in Section 111(d) of the Clean Air Act. For the reasons given, the answer is no." (emphasis added).[19]

---

[16] *Michigan v. EPA*, 268 F.3d 1075, 1078 (D.C. Cir. 2001) (quotation omitted).
[17] 42 U.S.C. § 7411(d)(1) (emphasis added).
[18] 87 *Fed. Reg.* 74,812.
[19] 142 S. Ct. at 2615-16. North Dakota shares certain select concerns voiced by several sister States with respect to the Proposed Rule's alarming disrespect of both the CAA's cooperative federalism framework (*see* State of West Virginia's and other States comment letter in this same docket, dated August 8, 2023) and the Supreme Court's decisions in *West Virginia et al.*

IV. CCS ON EXISTING LIGNITE- FUELED POWER PLANTS HAS NOT BEEN ADEQUATELY DEMONSTRATED

For nearly 20 years, North Dakota has actively supported the demonstration and development of CCS in North Dakota due to its superior carbon removal potential and associated large-scale job creation. While North Dakota's ongoing and significant efforts to advance CCS show tremendous promise, North Dakota does not believe that the technology currently meets the statutory requirement of CAA Section 111(a) for technology that "has been adequately demonstrated" to require its wide-spread application on the Proposed Rule's accelerated time frames.

North Dakota has actively supported obtaining such an outcome and believes it is well situated to obtain that reality in the future. However, CCS is not yet a proven technology that can be deployed at a national scale, certainly not at the unachievable capture rates contemplated by EPA's Proposed Rule. Under the Proposed Rule, EPA seeks to require CCS with 90% removal to be installed on units not included in other subcategories by January 1, 2030, with a retirement horizon of 2040 or later. EGUs without federally enforceable retirement dates that do not opt in to one of EPA's three other retirement subcategories are assigned to the post-2040 subcategory with its 90% CCS retrofit requirement by January 1, 2030.

North Dakota objects to this requirement because these EGUs likely differ widely in age, size, capacity factor, access to suitable CO_2 storage, technical and economic feasibility of retrofitting CCS, and because real world experience shows that even though EGUs can be designed to capture 90% or more of CO_2, the actual rates are lower due to operational difficulties and availability of the capture unit. These realities are closely documented by the University of North Dakota's Energy and Environmental Research Center ("EERC").[20]

None of the examples of successful plant operation that serve as EPA's basis for claiming adequate demonstration meet the proposed standards for the CCS pathway. EPA's examples "do not reflect the needs as set forth by EPA as they are examples of slipstream systems, are smaller capacity units, do not employ the full CCS process, and are capturing CO_2 at levels below 90%."[21] There are currently only two large-scale coal units with CCS – Boundary Dam Unit 3 and Petra Nova. Of these two, only Boundary Dam is in operation, and it is operating at levels below compliance with the Proposed Rule.[22]

The lack of infrastructure and storage currently available, and the long timeframes to develop storage locations, contradict EPA's assumption that affected EGUs will have viable options to take captured CO_2 away from the plant site to be properly geologically sequestered.

EPA's proposed compliance timeline is unrealistic. EPA erroneously presents a purportedly "reasonable" timeline of five years to deploy CCS and related infrastructure and equipment. As demonstrated by the EERC, a more realistic timeframe CCS deployment is at least 10 years.[23] EPA's timeline is an "expedited" version of a longer timeline developed by Sargent and Lundy and cited by EPA.[24] However, even the longer Sargent and Lundy schedule shows an accelerated timeline of six to seven years.[25] The technology, materials, infrastructure, and regulatory processes required to replace the current dispatchable thermal generation and power capacity within EPA's proposed timeframe cannot be met.

---

[20] *See* EERC, *Examination of EPA's Proposed Emission Guidelines Under 40 CFR PART 60, Final Report 2023-EERC-08-04*, Aug. 2023 ("EERC Report"), at 5-6, **Ex. 1**.

[21] *Id.* at 5.

[22] *Id.* at 7-8.

[23] EERC, *Timeline for Implementation of Full-Scale Carbon Capture* (July 2023), at 7, **Ex. 2**; Plains CO_2 Reduction ("PCOR") Partnership Timeline, Aug. 2023, **Ex. 3**.

[24] EERC Report at 12.

[25] *Id.*

EPA's reliance on *Portland Cement* as support for the Proposed Rule's CCS requirements is misplaced. *Portland Cement* is a CAA Section 111(b) New Source Performance Standard ("NSPS") case that allows EPA to look forward to technologies that "may fairly be projected for the regulated future,"[26] subject to "the restraints of reasonableness," without "crystal ball speculation," and dependent on a showing of "achievability."[27] Regardless of the exact details of the showing required by this language,[28] this is an <u>existing source</u> rulemaking under CAA Section 111(d) to which the forward-looking NSPS holdings of *Portland Cement* and related cases are inapplicable. EPA acknowledged in the CPP that courts had not ruled on the application of *Portland Cement* in Section 111(d) cases but recognized that the extensive caselaw in Section 111(b) cases involves new (not existing) sources.[29]

Congress has actively supported CCS research and demonstration for many years, mainly through programs administered by the U.S. Department of Energy ("DOE"). EPA's CCS requirements in the Proposed Rule are contradicted by the Congressional Research Service. The recent review of CCS programs by the Congressional Research Service summarizes this history and shows current legislative appropriations for CCS demonstration projects well into the future:

> DOE has funded [research and development] R&D of aspects of the three main steps of an integrated CCS system since at least 1997, primarily through its Fossil Energy and Carbon Management Research, Development, Demonstration, and Deployment program (FECM). CCS-focused R&D has come to dominate the coal program area within DOE FECM since 2010. Since FY2010, Congress has provided $9.2 billion (in constant 2022 dollars) total in annual appropriations for FECM ...
> The Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) provided $8.5 billion (nominal dollars) in supplemental funding for CCS for FY2022-FY2026 (see table below), including funding for the construction of new carbon capture facilities and commercial carbon storage facilities.[30]

[This space is intentionally left blank]

[26] *Lignite Energy Council,* 198 F.3d at 934 (citing *Portland Cement,* 486 F.2d at 391).
[27] *Portland Cement,* 486 F.2d at 391.
[28] *Compare West Virginia et al.*, 142 S.Ct. at 2629 (Kagan, JJ. dissenting) ("[H]as been adequately demonstrated…imposes meaningful constraints" including that the "best system has a "proven track record.").
[29] "In addition, although the D.C. Circuit has never reviewed a section 111(d) rulemaking, the Court has reviewed section 111(b) rulemakings on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011." 80 *Fed. Reg.* at 64,719.
[30] Congressional Research Service, *Carbon Capture and Sequestration (CCS) in the United States* (October 5, 2022) at 22-23.

Infrastructure Investment and Jobs Act Supplemental Appropriations for Carbon Capture and Storage Programs

FY2022 through FY2026 (in thousands of nominal dollars)

Program	FY2022	FY2023	FY2024	FY2025	FY2026	Total FY2022-FY2026
Front-End Engineering and Design (carbon capture)	20,000	20,000	20,000	20,000	20,000	100,000
Carbon Capture Large-Scale Pilot Projects	387,000	200,000	200,000	150,000	—	937,000
Carbon Capture Demonstration Projects	937,000	500,000	500,000	600,000	—	2,537,000
Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA)	3,000	2,097,000	—	—	—	2,100,000
Carbon Utilization	41,000	65,250	66,563	67,941	69,388	310,141
Carbon Storage Validation and Testing	500,000	500,000	500,000	500,000	500,000	2,500,000

Source: Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58), Division J.

Congress's authorization of some $2.5 billion for CCS demonstration projects to be spent over the period FY2022 to FY2026 clearly illustrates the fact that CCS has not been "adequately demonstrated" for purposes of this EPA proposed Section 111(d) rulemaking.

A. EPA's Own Assessments Contradict the Proposed Rule

EPA's claims that CCS is the BSER for existing coal-fired EGUs are directly contradicted by EPA's own "Greenhouse Gas Mitigation Measures for Steam Generating Units, Technical Support Document" ("GHG TSD"). The GHG TSD information documents how CCS is not BSER since it has not been adequately demonstrated (from a technical perspective), [31] is not commercially available[32] (these are not "off-the-self" products nor has it been used on North Dakota lignite flue gas), and is not economically reasonable (unless significant subsidies are in place)[33]. Further, even with these significant subsidies, there is significant industry reservation due to the technological uncertainty and financial risk.

According to the data EPA used from the Global CCS Institute[34] to support CCS as BSER in the "Power Generation" industry, there is not a single facility in the power generation sector in the United States currently implementing CCS. Yet, EPA uses the Global CCS Institute data to claim the technology is already being deployed and has been demonstrated.[35] EPA then goes on to significantly misrepresent the success of the projects (and there are only two projects) relied on to

---

[31] EPA-HQ-OAR-2023-0072-0061 at 23.

[32] *Id.* at 24.

[33] *Id.* at 23, 24, 25, and 35. These are a few example statements.

[34] *Id.* at Attachment 1 (available at: https://status22.globalccsinstitute.com/2022-status-report/appendices/ (last visited Aug. 7, 2023)).

[35] *Id.* at 22.

justify its position that BSER is CCS. The only facility in the United States, Petra Nova, had its operation suspended due to operational challenges in mid-2020 and has not started back up for economic reasons. The one, non-US facility, which has implemented CCS – the Boundary Dam Station in Canada – has also experienced significant issues, and contrary to EPA's claims, this project was considered a failure,[36] its future is uncertain,[37] and it is unlikely that CCS will be implemented on the remaining units at Boundary Dam due to financial issues.[38] Given the significant and frequent, issues that both Petra-Nova and Boundary Dam experienced in only a few short years, it is clear that CCS is not ready for mandatory widespread deployment as it has yet to be adequately demonstrated even one time. EPA's own information and analysis reveal the arbitrariness of the Proposed Rule.

B. CCS Projects to Date in North Dakota

North Dakota has been a leader in CCS technology development for North Dakota lignite-fueled power plants, and North Dakota is well positioned to be the first state with a full-scale EGU CCS facility. As such, North Dakota remains cautiously optimistic that CCS technology can be implemented at a large scale, considering the significant efforts put forth in research, development, and testing of this state-of-the-art technology.

North Dakota has been actively working to test, develop, and implement CCS. Red Trail Energy was the first facility constructed under North Dakota's primacy and since then, North Dakota Industrial Commission ("NDIC") also approved Project Tundra, a $1.4 billion project in North Dakota in 2022. Project Tundra encompasses multiple facilities for CCS of the coal-fired power plant, the Milton R. Young Station ("MRYS") by Minnkota Power Cooperative ("Minnkota"). Dakota Carbon Center East Project LLC ("DCC East") submitted an air quality permit to construct application to the NDDEQ in June 2023 requesting approval to construct a full-scale CCS plant adjacent to MRYS, where DCC East would receive flue gas from MRYS and capture up to 13,000 tons per day of CO_2. Contrary to EPA's claims, this is the first of its kind and size proposed in North Dakota or the world. Given that this is the first potential CCS project of such significant magnitude, CCS has not been adequately demonstrated and its commercial availability is also uncertain at best.

An independent energy producer, Rainbow Energy Center, purchased North Dakota's "most efficient power plant," Coal Creek Station, on May 1, 2022.[39] It utilizes up to 8 million tons of beneficiated lignite per year to fuel Coal Creek Station, produces 1,151 MW of electricity per hour, and has an estimated $1.5 billion beneficial impact to North Dakota. The energy is transmitted from central North Dakota to Minnesota. Rainbow Energy Center anticipates completion of its CCS front-end engineering and design study with EERC in early 2024.

V. THE PROPOSED RULE WOULD DIRECTLY HARM NORTH DAKOTA'S LONGSTANDING SOVEREIGN INTERESTS IN PROMOTING THE DEVELOPMENT AND FUTURE APPLICATION OF CCS IN NORTH DAKOTA

The Tenth Amendment of the United States Constitution provides that the "powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people." This is a basis for the State of North Dakota's exercise of its sovereign authority and discretion to develop and advance policies and initiatives to encourage the

[36] In 2016, Sen. Joe Manchin (D. W.Va.) called Boundary Dam a "failed operation" for technical challenges at the time (Greenwire, April 27, 2016).

[37] *See* https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Carbon-Capture-and-Storage/Boundary-Dam-Carbon-Capture-Project. There is no recent information available on boundary Dam CCS on the SaskPower website.

[38] 83 *Fed. Reg.* 65,424; 65,436 n.61 (Dec. 20, 2018).

[39] Stacy Tschider, Presentation: Rainbow Energy Center, relating to Rainbow Energy Center's vision of the future of Coal Creek Station and the successful operation of a coal plant in a low carbon world (Aug. 7, 2023), **Ex. 6**.

development of CCS as a means to continue the beneficial use of the State's lignite natural resources with lower associated carbon emissions.

> "It is one of the happy incidents of the federal system that a single courageous State may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risk to the rest of the country."[40]

North Dakota, through its (1) Legislature, (2) NDIC, (3) EERC, (4) Plains CO_2 Reduction ("PCOR") Partnership, (5) Clean Sustainable Energy Authority ("CSEA"), and (6) industries, has established and implemented numerous specific sovereign policies and dedicated significant State resources to developing and incentivizing CCS. These efforts combined with North Dakota's unique geology have led North Dakota to becoming a primary leader among the States for CCS not only in policy but also in practice: North Dakota was the first State to receive primacy under the Safe Drinking Water Act for Class VI injection wells, and it is the future home to one of the largest CCS facilities in the world.

Since 2008, when North Dakota formed an *ad hoc* CO_2 storage workgroup, with representatives from the North Dakota Governor's Office, the Oil and Gas Division of NDIC, NDDEQ, the Office of the Attorney General, the Lignite Energy Council, the North Dakota Petroleum Council, EERC, and other energy industry and legal experts, North Dakota has been at the forefront in striving to create a feasible regulatory framework for the geologic storage of CO_2, also referred to as carbon capture and storage.[41] As a result of the CO_2 Storage Workgroup, North Dakota exercised its sovereign authority to create laws and a subsequent regulatory framework to implement CCS in the State.[42]

If finalized, the Proposed Rule would directly threaten the future viability of North Dakota's significant sovereign efforts and investments.

A. Sovereign Actions by the Legislature

In 2009, the Legislature enacted N.D.C.C. Chapter 38-22 and 47-31, authorizing the statutory regime for geologic storage of CO_2, defining pore space ownership and setting up long-term liability laws. Under N.D.C.C. § 38-22-03, the Legislature delegated authority to the NDIC "over all persons and property necessary to administer and enforce" the N.D.C.C. Ch. 38-22 and its objectives.

Effective in 2010, the North Dakota Administrative Code, ("N.D. Admin. Code") Ch. 43-05-01 Geologic Storage of Carbon Dioxide, provided a first-of-its-kind state regulatory framework that incorporates permitting, well construction, and detailed engineering and geological data analyses, along with a CO_2 injection plan that includes a description of the mechanisms of geologic confinement to ensure the prevention of horizontal or vertical migration of CO_2 beyond the proposed storage reservoir.[43] With this update to the N.D. Admin. Code, North Dakota became the first state in the nation to adopt a complete and comprehensive legal and regulatory framework in place for CO_2 storage.[44]

In the N.D.C.C. Ch. 38-22, the Legislature explicitly stated the legislative intent for this new policy:

---

[40] *New State Ice Co. v. Liebmann*, 285 U.S. 262 (1932) (Frankfurter, J. *dissenting*).
[41] *See, EERC, Regulatory Frameworks and Permitting Considerations for Geologic Storage of Carbon Dioxide in PCOR Partnership Region* (Jan. 2023), at 13, **Ex. 4**.
[42] *Id.*
[43] EERC Report at 14.
[44] *Id.*

> "It is in the public interest to promote the geologic storage of carbon dioxide. Doing so will benefit the state and the global environment by reducing greenhouse gas emissions. Doing so will help ensure the viability of the state's coal and power industries, to the economic benefit of North Dakota and its citizens. Further, geologic storage of carbon dioxide, a potentially valuable commodity, may allow for its ready availability if needed for commercial, industrial, or other uses, including enhanced recovery of oil, gas, and other minerals. Geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners. Obtaining consent from all owners may not be feasible, requiring procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources."[45]

The Legislature has appropriated tens of millions of dollars to promote the development of CCS through multiple state programs and funds. For example, in 2011, the Legislature appropriated \$532,000 to the CO_2 Storage Facility Administrative Fund. This fund, created under N.D.C.C. § 38-22-05, receives the fees associated with CCS permitting and may be use the money for "expenses in processing permit applications; regulating storage facilities during their construction, operational, and preclosure phases; and making storage amount determinations under section 38-22-23."[46]

In 2019, the Legislature enacted House Bill 1439, which exempted CO_2 used for geologic storage from property taxes and sales and use taxes and incentivized the use of anthropogenic carbon dioxide for enhanced oil recovery under N.D.C.C. Ch. 38-08. The bill also authorizes a fee structure for captured CO_2 injections, with an exemption for projects that produce CO_2 from coal and are located outside of the Bakken and Three Forks formations. To encourage industry adoption of CCS, North Dakota offers a reduction in coal conversion tax dependent on the amount of CO_2 that is captured. For example, facilities that capture 20% of their CO_2 emissions are eligible for a 20% reduction of the state general fund share based on gross receipts. This reduction can reach 50% for facilities that capture 80% or more of their carbon emissions.

In 2021, the Legislature authorized the creation of CSEA in House Bill 1452. The Legislature also updated utility rates to allow recovery for CCS costs in Senate Bill 2206 and updated N.D.C.C. Ch. 38-22 to include "secure geological storage" to conform with federal updates to the Internal Revenue Code, 45Q on tax credits.

In 2023, the Legislature created a Carbon Capture Education Program under the NDIC in House Bill 1014 to contract for carbon capture and utilization education and marketing in consultation with three contributions of \$100,000 from the Lignite Research Council, the Oil and Gas Research Council, and the Renewable Energy Council. The Legislature also rejected eleven bills that attempted to limit the ability for the state to regulate and provide economic certainty to carbon capture projects making clear the Legislature's intent to support policies that promote the State's burgeoning carbon capture industry.

B. Actions Taken by the NDIC

The NDIC consists of the Governor of North Dakota, the Attorney General, and the Commissioner of Agriculture, and regulates several North Dakota industries. Under N.D.C.C.§ 38-22-03, the Legislature delegated specific authority to the NDIC to regulate activities related to CCS.

[45] N.D.C.C. § 38-22-01.
[46] N.D.C.C. § 38-22-14.

Through its financing authority and oversight of numerous grant programs, the NDIC has invested millions of dollars in the past 15 years into the research and development of carbon capture technologies and geologic exploration to survey underground storage locations in deep saline formations in North Dakota. The NDIC approves grants and loans through its Lignite Research Program and its Clean Sustainable Energy Authority to carry out the legislative purposes of N.D.C.C. Ch. 38-22.

One of the NDIC's divisions, the Department of Mineral Resources' Oil and Gas Division carries out the regulatory responsibilities for the programs and permitting associated with geologic sequestration. Under N.D.C.C. § 38-22-08, there are 14 requirements that must be met before the NDIC can issue a permit, and the N.D. Admin. Code provides additional requirements and procedures for the NDIC to issue a permit. Under N.D.C.C. § 38-22-17, the NDIC has the power to issue a certificate of project completion.

In 2013, the NDIC amended N.D. Admin. Code 43-05-01 to meet the "as stringent as" standard by incorporating EPA's Class VI UIC program regulations under the federal Safe Drinking Water Act.[47] Thereafter, North Dakota applied to be the primary enforcement authority for UIC program. In 2015, the Legislature authorized a Legislative Management Study to review the potential benefits and costs to industry, State, and environment for using carbon capture enhanced recovery methods.

The NDIC's Lignite Research Program provides grants and funding for near term, practical research and development projects that provide the opportunity to preserve and enhance development of our State's abundant lignite resources, which includes CCS. Lignite Research Program is funded from several sources including the coal severance tax, coal conversion tax, and oil and gas tax revenues with approximately $7.5 million available each year.

In 2017, the NDIC approved Lignite Research Program's creation of the Advanced Energy Technology Fund to further accelerate the deployment of CCS and other emerging technologies in North Dakota. The Legislature also passed a concurrent resolution requesting the United States Congress and the President to enact legislation expanding federal tax credits to cover carbon capture, utilization, and storage, and providing other incentives for carbon capture focused policies.

In 2018, nearly five years after North Dakota applied, the EPA approved North Dakota's request to implement and enforce its own Class VI UIC program. Class VI injection wells have extensive site characterization and comprehensive monitoring requirements. This approval made North Dakota the first state to obtain Safe Drinking Water Act primacy for Class VI UIC wells, which is necessary for the long-term storage of carbon dioxide captured from industrial and energy related sources. NDIC's Oil and Gas Division regulates Class VI injection wells.

Also in 2018, the NDIC's Lignite Research Program approved a $15 million grant to Minnkota to fund a preliminary study regarding a significant CCS project at Minnkota. It also approved another $5 million grant to Minnkota in 2020 to allow for the evaluation of additional geologic storage of CO_2 in underground formations adjacent to Minnkota's plant. This State investment led to another $9.8 million grant from the DOE in 2019.

In 2021, after a 5-year investigative period, the NDIC approved the first Class VI injection permit for an operational commercial-scale CCS project in North Dakota, Red Trail Energy. This approval process was completed in partnership with the DOE and the EERC. In 2022, the NDIC approved its second Class VI storage facility permit for Minnkota's Project Tundra.

[47] *EERC, Regulatory Frameworks*, at 14.

C. Lignite Research and Development by EERC

EERC began in the 1950s as a lignite research laboratory and is recognized as one of the world's leading developers of cleaner, more efficient energy to power the world and environmental technologies to protect and clean our air, water, and soil. Over the past 15 years, EERC has been involved the testing, data collection, applied research, and technological development for CCS. In 2019, EERC was designated as the State Energy Research Center for North Dakota. It receives $5 million from the Legislature every two years for the research and development of technologies geared towards addressing North Dakota's current and future CCS CO_2 reduction needs, challenges, and opportunities.

Since 2005, the NDIC has allocated $46,151,897.00 to the EERC to support carbon management efforts and initiatives.[48] Accordingly, one of EERC's main focuses is on research and development supporting CCS. EERC has been instrumental in providing essential technical information on CCS for multiple projects focused on carbon management, including Red Trail Energy, Project Tundra, the PCOR Partnership, and North Dakota Carbon Storage Assurance Facility Enterprise ("CarbonSAFE").

D. North Dakota's Extensive Support of the PCOR Partnership

North Dakota's EERC is the leader of the PCOR Partnership. The PCOR Partnership is one of seven regional carbon sequestration partnerships operating under the DOE's National Energy Technology Laboratory Regional Carbon Sequestration Partnerships Program. It is made up of public and private stakeholders in the United States and Canada. Its objectives are to address regional capture, transport, use, and storage challenges facing commercial CCS deployment by focusing on: strengthening the technical foundation for geologic CO_2 storage and enhanced oil recovery; improving application of monitoring technologies; promoting integration between capture, transportation, use, and storage industries; providing scientific support to regulators and policy makers; advancing capture technologies; and facilitating regulatory frameworks.

EERC receives funding from both the State and the DOE. Namely, the NDIC sponsored $240,000 in 2003 for the PCOR Partnership's Phase I: Characterization Phase, $500,000 and $720,000 in 2005 for Phase 2: Validation Phase, and $500,000 and $2,400,000 in 2008 for Phase 3: Deployment Phase.[49]

In Phase 1, the PCOR Partnership developed a suite of practical and environmentally sound strategies for carbon management that represented projects with commercial potential and a mix that would support future projects both dependent and independent of CO_2 monetization. The PCOR Partnership identified, quantified, and characterized over 1,000 stationary sources within its defined region that have a combined annual output of nearly 553 million tons of anthropogenic CO_2 from stationary sources.

Phase 2 activities focused on carbon storage field validation projects designed to develop the local technical expertise and experience needed to facilitate future large-scale CO_2 storage efforts in the region's subsurface and terrestrial settings.

Phase 3 efforts included designing and conducting monitoring, verification, and accounting programs as part of at least two large-volume commercially oriented projects that focused on injecting CO_2 into deep saline geologic formations for CO_2 storage. Large-scale field testing

---

[48] *See* NDIC Funded Projects and Funding Amounts that have been Contracted to the EERC from October 2003 through June 2023, for Projects related to CO2 Capture, Utilization, and Storage (CCUS), **Ex. 5.**
[49] *Id.*

confirmed that a project of at least 1 million metric tons of captured CO_2 per year can achieve safe, permanent, and economical storage.

E. The North Dakota CarbonSAFE Project

Through the North Dakota CarbonSAFE Project, the EERC assists in characterizing geologic storage sites suitability to permanently store CO_2. CarbonSAFE is part of the regional effort to ensure reliable, affordable energy, the wise use of North Dakota's resources, and foster wide-scale commercial deployment of CCS under DOE's CarbonSAFE Initiative. The purpose of the CarbonSAFE projects is to improve and optimize procedures related to: 1) project site screening and selection; 2) site characterization; 3) baseline monitoring; and 4) subsurface monitoring. In addition, CarbonSAFE aims to compile information necessary to submit appropriate permits and design injection and monitoring strategies for commercial-scale projects.

Under North Dakota CarbonSAFE, EERC evaluated two ideal geologic storage complexes located adjacent to separate coal-fired facilities, gathered local public and stakeholder feedback, and conducted a regulatory and economic analysis. North Dakota CarbonSAFE research has proven the feasibility of CO_2 use for enhanced oil recovery in both conventional and unconventional oil fields.

F. The North Dakota CSEA

The CSEA was established to encourage large scale development and commercialization of emission reduction technology and projects within the energy industry, and does so by supporting research, development and technological advancements through partnerships and financial support for the large-scale development and commercialization of projects, processes, activities, and technologies that reduce environmental impacts and increase sustainability of energy production and delivery.

The creation of the CSEA in 2021 included an allocation of $25 million in grant opportunities and $250 million in commercialization loan programs. From this funding, the CSEA approved $100 million in a commercialization loan for Project Tundra and a $7 million grant to EERC for the front-end engineering and design for the carbon capture facility at Coal Creek Station in North Dakota. The CSEA received an additional allocation of $30 million in grant opportunities and $250 million in commercialized loans from the Legislature in 2023.

G. North Dakota Industries

North Dakota industries are naturally incentivized to invest in developing CCS given North Dakota's unique geology, which is ideal for safe and permanent geologic storage of CO_2. Beginning in 2000, the Dakota Gasification Company's Great Plains Synfuels Plant ("DGC Plant") began sending CO_2 through a 205-mile pipeline to Saskatchewan, Canada, where oil companies use it for enhanced oil recovery operations that result in permanent geologic sequestration. From 2000 to present day, the DGC Plant has captured and transported more than 40 million metric tons of CO_2 for geologic sequestration.

Today, North Dakota is one of only two States (Wyoming being the other) that has Safe Drinking Water Act primacy for all well classes (I, II, III, IV, V, and VI). EPA directly implements the Class VI program in all other States, territories, and tribes. For North Dakota, the NDIC implements and enforces its Class VI program and issues Class VI permits. As such, CCS sites in North Dakota do not have to go through the lengthy process associated with seeking federal permit approval. The shorter regulatory permitting process also encourages North Dakota's energy industry to implement CCS.

VI. THE PROPOSED RULE INFRINGES UPON NORTH DAKOTA'S SOVEREIGN AUTHORITY OVER INTRASTATE ENERGY PRODUCTION AND CONSUMPTION.

The regulation of electricity generation, transmission, and distribution has historically been the authority of individual states and state regulators, with few exceptions, wholesale rates, and targeted interference with interstate markets.[50] Despite the modern development of energy markets, grid, and utility services, retail sales of electricity and the development of regulated utility resources continue to be within the jurisdictional sphere of the States. This is especially pronounced in States like North Dakota.

North Dakota's authority over the intrastate generation and consumption of electricity is "one of the most important functions traditionally associated with the police powers of the States."[51] Despite the modern development of energy markets, grid, and utility services, retail sales of electricity and the development of regulated utility resources continue to be within the jurisdictional sphere of the States. Congress recognized State authority over these "important functions" in the Federal Power Act ("FPA"), which confines federal authority over electricity markets to "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce."[52] The FPA and other federal energy statutes respect the States' "traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost and other related state concerns."[53]

The North Dakota Public Service Commission ("ND PSC") is a state agency created by the North Dakota Constitution to regulate and oversee intrastate energy production and consumption.[54] ND PSC has jurisdiction over economic regulation of public utilities and the orderly development and siting of energy infrastructure within the State. It is charged with determining whether to authorize generation, transmission, and other capital-intensive infrastructure in North Dakota that is needed by jurisdictional utilities, and has the authority to determine the generation mix, planning reserve margin, and enforce reliable service obligations of jurisdictional utilities.[55] ND PSC is a member and actively participates in the Organization of Midcontinent Independent System Operator ("MISO") and the Regional State Committee for Southwest Power Pool ("SPP"). Both MISO and SPP are engaged in transmission planning processes to accommodate the growth of renewable generation and the need to move that generation to the markets.[56]

The ND PSC has a statutory duty to ensure that North Dakotans receive a *reliable* supply of electricity and natural gas at just and reasonable rates. For the reasons stated below, the Proposed Rule infringes on the ND PSC's ability to fulfill its constitutional responsibilities and violates the rights historically and statutorily reserved for the States under the FPA.

---

[50] *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 266 (2016), *as revised* (Jan. 28, 2016).
[51] *Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983).
[52] 16 U.S.C. § 824(a); *see also id.* § 824(b)(l).
[53] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983); *cf.* 16 U.S.C. § 808(d)(2)(A).
[54] *See*, N.D. Const. art. 5, § 2.
[55] N.D.C.C. § 49-02 *et seq.*
[56] Isaac Orr et al., *Forecasting Resource Adequacy in Southwest Power Pool Through 2035* (May 15, 2023), https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/Southwest%20Power%20Pool%20Resource%20Adequacy%20OTR%20CCR%20v%202%205-23-2023.pdf

The North Dakota Transmission Authority ("NDTA") was created by the Legislature with authority to make grants or loans; provide financing for approved transmission projects through bonds; own, lease, rent and dispose of transmission facilities; enter into contracts to construct, maintain and operate transmission facilities; engage in the relevant investigation and planning processes for transmission corridors; and participate in regional transmission organizations.[57] The purpose of the NDTA is to diversify and expand the North Dakota economy by facilitating development of transmission facilities to support the production, transportation, and utilization of North Dakota electric energy.[58] The Proposed Rule inhibits NDTA from carrying out their sovereign purpose by increasing the risk potential for insufficient operating reserves, affecting NDTA's statutory right to facilitate effective transmission of North Dakota electric energy.[59]

The preamble to the Proposed Rule acknowledges the critical need for reliability, but EPA fails to analyze and address reliability in the Proposed Rule. Rather, EPA relies on "design elements," its intention to exercise its enforcement discretion, and a resource adequacy analysis.

In the Proposed Rule's Preamble, EPA conflates resource adequacy with reliability. The Resource Adequacy Technical Support Document ("RA TSD") does not analyze reliability. The RA TSD "is meant to serve as a *resource adequacy* assessment of the impacts of the final rule and how projected outcomes under the final rule compare with projected baseline outcomes in the presence of the [Inflation Reduction Act]."[60] EPA points to third party studies that purportedly demonstrate "how reliability continues to be maintained under high variable renewable penetration scenarios."[61] Even assuming these studies are correct (which North Dakota disputes), the ability to maintain reliability with an influx of new intermittent, weather-dependent renewable resources does not address the reliability impacts of potential retirement of significant volumes of existing baseload fossil-fuel fired generation or operation of new generating resources at lower capacity factors.[62]

Further threatening electric reliability in North Dakota is the anticipated retirement of some EGUs as a result of the implementation of the Proposed Rule, which the Proposed Rule contemplates with the projection that total coal retirements between 2023 and 2035 will be 126 GW (or 18 GW annually), as compared to an average historical retirement rate of 11 GW per year from 2015-2020.[63] The retirements of dispatchable resources that can immediately increase or decrease power generation as needed results in significant uncertainty in the power grid, impacting the electric cooperatives' ability to reliably provide power and increasing the odds of unplanned outages.[64]

---

[57] N.D.C.C. § 17-05-05.

[58] *Id.*

[59] Claire Vigesaa, Presentation: North Dakota Transmission Authority, regarding studies on the impact of the Environmental Protection Agency's (EPA's) regulations on the resource adequacy of the Midcontinent Independent System Operator and Southwest Power Pool grids (Aug. 7, 2023), **Ex. 7.**

[60] EPA, *Resource Adequacy Analysis Technical Support Document* (May 23, 2023). Available at: https://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf

[61] EPA-HQ-OAR-2023-0034 at 2.

[62] Orr, *Forecasting Resource Adequacy in Southwest Power Pool Through 2035.*

[63] North Dakota currently has approximately 3,895 MW of coal-fired generation. U.S. Energy Information Administration, Energy Atlas (July 10, 2020), https://atlas.eia.gov/datasets/eia::power-plants/explore.

[64] NDIC, *North Dakota Transmission Authority presents electric grid resilience report* (July 29, 2022, 11:00 PM), https://www.ndic.nd.gov/news/north-dakota-transmission-authority-presents-electric-grid-resilience-report

Reliability is even more crucial when considering that NDTA's power forecast for 2021 indicates an increase in energy demand of 10,000 GW over the next 20 years.[65]

Coal and natural gas EGUs are necessary to ensure reliability during times when intermittent generation is both available and unavailable. Transitioning reserve power generation sources to intermittent sources increases the risk of outages as the nature of the energy source is not consistent like coal.[66] Accordingly, the Proposed Rule not only fails to provide an analysis of reliability impacts, but also threatens the grid's reliability.

Regional transmission organizations like MISO and SPP mandate load-serving entities to maintain sufficient generation capacity.[67] EPA's carbon standards could have major adverse impacts on the region's coal fleet, with 25 GW subject to CCS or gas co-firing requirements.[68] The loss of generation capacity would be made up through the construction of smaller natural gas combustion turbines using existing sites and interconnections.[69] This would exacerbate occurrences of observed natural gas scarcity and price increases.[70]

Given that predicted impacts of climate change include more frequent and more severe extreme weather, grid reliability is increasingly important. The devasting effects of Winter Storm Elliott from just last year are telling. On December 23, 2022, this storm caused unplanned natural gas outages that accounted for 23 GW.[71] Afterwards, MISO had to adjust the operating capacity ratings for the Coal Creek Station in North Dakota because Coal Creek Station provided more reliable energy during the storm, operating at maximum capacity to try to cover the outages.[72]

Not only does the reliability of the electrical system play a critical role in sustaining lives and livelihoods in modern society, but so does the affordability of electricity to North Dakota's citizens. The Proposed Rule estimates total compliance costs of $10-14 billion. However, the ND PSC asserts that the combined costs (costs of replacement generation to meet capacity requirements, additional electrical and pipeline transmission costs for the buildout of renewable and new combustion turbine generation, and CCS and hydrogen co-firing technology costs) have a likelihood of $10-14 billion in capital costs solely for North Dakota. Many States and customers are still grappling with payment of customer fees due to deferred costs and ratepayer-backed bonds that try to mitigate the burden on customers.[73]

---

[65] NDTA, Annual Report (July 1, 2021 to June 30, 2022), https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/ta-annualreport-22.pdf

[66] Orr, *Forecasting Resource Adequacy in Southwest Power Pool Through 2035.*

[67] *Id.*

[68] Brian Tulloh, Presentation: MISO Updates – Reliability, Transmission, and EPA Regulations to the North Dakota Legislative Assembly (Aug. 7, 2023), **Ex. 8.**

[69] Orr, *Forecasting Resource Adequacy in Southwest Power Pool Through 2035.*

[70] *Id.*

[71] MISO Reliability Subcommittee, Overview of Winter Storm Elliott December 23, Maximum Generation Event (Jan. 17, 2023), https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf;

[72] *Id.*

[73] *See* Kansas Corporation Commission Approval of Settlement and Financing to Recover 2021 Winter Storm Costs using Low Interest Bonds. https://www.kcc.ks.gov/news-10-13-22; *See also* Matter of Oklahoma Dev. Fin. Auth., 2022 OK 48, ¶ 0, 511 P.3d 1048.

Even if the Proposed Rule carved out units capable of 24/7 dispatch with high-capacity factors and allowed these units to operate at lower capacity factors, they would be too costly to operate. If the Proposed Rule causes premature retirements of coal and natural gas units capable of 24/7 dispatch with high-capacity factors because of the cost of investments are not commercially viable, there will be less overall availability of gas and likely more unplanned outages. Success in addressing these issues relies heavily on retaining existing thermal EGUs and delaying the retirements until actual, feasible solutions can be implemented.

The Proposed Rule will increase costs, which, compounded with inflation, will negatively impact the affordability of electric and gas services, resulting in a disproportionate effect on low-income citizens. Given the high rural populations in North Dakota, pricing low-income citizens out of a reliable energy source creates a social justice issue with devasting impacts on North Dakotans' lives.

VII. EPA SHOULD WITHDRAW THE FLAWED 2015 NSPS

In 2015, the EPA promulgated two rules that addressed CO_2 emissions from fossil fuel-fired EGUs. The first rule promulgated standards of performance for new fossil fuel-fired EGUs.[74] The second rule promulgated emission guidelines for existing sources: The CPP.[75]

Along with the CPP, North Dakota filed a Petition for Judicial Review of EPA's 2015 NSPS in the U.S. Court of Appeals for the D.C. Circuit.[76] On August 10, 2017, the D.C. Circuit ordered that North Dakota and the other's petitions be held in abeyance pending further order of the Court and directed EPA to file status reports at 90-day intervals, beginning October 27, 2017.[77]

On January 20, 2021, President Biden signed Executive Order 13990 on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis."[78] The Executive Order, along with a list of agency actions accompanying the Executive Order, specifically directs EPA to "review and, as appropriate and consistent with applicable law, take action to address" several EPA actions (including the 2015 NSPS and associated modifications) to the extent they conflict with the Executive Order's stated policies of, among other things, improving public health, protecting the environment and reducing greenhouse gas emissions.[79]

EPA's Proposed Rule proposes to amend and affirm the new source performance standards promulgated in EPA's 2015 NSPS Rule. For the reasons stated herein with respect to the issues surrounding CCS for existing EGUs, EPA cannot lawfully maintain its 2015 NSPS determination that CCS is a proper BSER for new sources under Section 111(b) of the CAA.

[74] NSPS, Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule 80 Fed. Reg. 64510 (Oct. 23, 2015).
[75] EPA's 2015 NSPS is codified in 40 CFR part 60, subpart TTTT.
[76] *See State of North Dakota, et al. v. EPA*, Case No. 15-1381 (and consolidated cases).
[77] *Id.*
[78] 86 *Fed. Reg.* 7037 (Jan. 25, 2021).
[79] *Id.* "Fact Sheet: List of Agency Actions for Review," at "U.S. Environmental Protection Agency" § 3, https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/20/fact-sheet-list-of-agency-actions-for-review/.

Even if the Proposed Rule carved out units capable of 24/7 dispatch with high-capacity factors and allowed these units to operate at lower capacity factors, they would be too costly to operate. If the Proposed Rule causes premature retirements of coal and natural gas units capable of 24/7 dispatch with high-capacity factors because of the cost of investments are not commercially viable, there will be less overall availability of gas and likely more unplanned outages. Success in addressing these issues relies heavily on retaining existing thermal EGUs and delaying the retirements until actual, feasible solutions can be implemented.

The Proposed Rule will increase costs, which, compounded with inflation, will negatively impact the affordability of electric and gas services, resulting in a disproportionate effect on low-income citizens. Given the high rural populations in North Dakota, pricing low-income citizens out of a reliable energy source creates a social justice issue with devasting impacts on North Dakotans' lives.

VII. EPA SHOULD WITHDRAW THE FLAWED 2015 NSPS

In 2015, the EPA promulgated two rules that addressed CO_2 emissions from fossil fuel-fired EGUs. The first rule promulgated standards of performance for new fossil fuel-fired EGUs.[74] The second rule promulgated emission guidelines for existing sources: The CPP.[75]

Along with the CPP, North Dakota filed a Petition for Judicial Review of EPA's 2015 NSPS in the U.S. Court of Appeals for the D.C. Circuit.[76] On August 10, 2017, the D.C. Circuit ordered that North Dakota and the other's petitions be held in abeyance pending further order of the Court and directed EPA to file status reports at 90-day intervals, beginning October 27, 2017.[77]

On January 20, 2021, President Biden signed Executive Order 13990 on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis."[78] The Executive Order, along with a list of agency actions accompanying the Executive Order, specifically directs EPA to "review and, as appropriate and consistent with applicable law, take action to address" several EPA actions (including the 2015 NSPS and associated modifications) to the extent they conflict with the Executive Order's stated policies of, among other things, improving public health, protecting the environment and reducing greenhouse gas emissions.[79]

EPA's Proposed Rule proposes to amend and affirm the new source performance standards promulgated in EPA's 2015 NSPS Rule. For the reasons stated herein with respect to the issues surrounding CCS for existing EGUs, EPA cannot lawfully maintain its 2015 NSPS determination that CCS is a proper BSER for new sources under Section 111(b) of the CAA.

[74] NSPS, Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule 80 Fed. Reg. 64510 (Oct. 23, 2015).
[75] EPA's 2015 NSPS is codified in 40 CFR part 60, subpart TTTT.
[76] *See State of North Dakota, et al. v. EPA*, Case No. 15-1381 (and consolidated cases).
[77] *Id.*
[78] 86 *Fed. Reg.* 7037 (Jan. 25, 2021).
[79] *Id.* "Fact Sheet: List of Agency Actions for Review," at "U.S. Environmental Protection Agency" § 3, https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/20/fact-sheet-list-of-agency-actions-for-review/.

VIII. CONCLUSION

For the reasons stated herein, the State of North Dakota respectfully urges EPA to withdraw the Proposed Rule.

Sincerely,

Matthew Sagsveen

Matthew Sagsveen
Assistant Attorney General

cc: Kevin Cramer, United States Senator, North Dakota
John Hoeven, United States Senator, North Dakota
Kelly Armstrong, United States Representative, North Dakota
John Reiten, North Dakota Governor's Office
Ryan Norrell, North Dakota Governor's Office
L. David Glatt, P.E., Director, North Dakota Department of Environmental Quality
Lynn Helms, Ph.D., Director, North Dakota Department of Mineral Resources
Karen Tyler, Interim Executive Director, North Dakota Industrial Commission
Randy Christmann, Chair, North Dakota Public Service Commission
Julie Fedorchak, North Dakota Public Service Commissioner
Claire Vigessa, Director, North Dakota Transmission Authority

DAVE YOST
OHIO ATTORNEY GENERAL

Administration
Office 614-466-8980
Fax 614-466-5087

August 8, 2023

Michael S. Regan
Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20460

Docket No: EPA–HQ–OAR–2023–0072

Re: Ohio and 17 States' comments regarding proposed rulemaking RIN 2060–AV09, as set forth in 40 CFR Part 60, 88 Federal Register 33240.

Dear Administrator Regan:

The States of Ohio, Alabama, Arkansas, Florida, Georgia, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Nebraska, New Hampshire, South Carolina, South Dakota, Texas, Utah, and Virginia submit these comments in opposition to the notice of proposed rulemaking entitled, "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," set forth at 88 Fed. Reg. 33240 (May 23, 2023) (the "Proposed Rule").

Coal- and natural-gas-fired power plants together provide about 60% of America's electricity. In Ohio alone, coal generates over 25%, and natural gas over 60%, of the State's electricity.[1] In May of this year, the EPA proposed a rule to regulate greenhouse-gas emissions—or "GHG" emissions, to borrow the EPA's clunky acronym—from these already-existing power plants. The Proposed Rule also regulates

[1] *Ohio Net Electricity Generation by Source, March 2023*, Energy Information Administration, Electric Power Monthly, *available at* https://perma.cc/GGR7-F29H; *see* OHIO *State Profile and Energy Estimates*, *June 2023*, U.S. Energy Information Administration, https://perma.cc/HB4B-DZ9Q.

greenhouse-gas emissions from new coal- and natural-gas-fired power plants. The EPA claimed authority to issue this rule under the New Source Performance Standards program set forth in Section 111[2] of the Clean Air Act[3]. This Proposed Rule, much like the Clean Power Plan that preceded it,[4] determines that the "best system" for reducing greenhouse gas emissions involves shifting away from coal- and natural-gas-powered energy generation to generation from cleaner energy sources. The Proposed Rule seeks to accomplish this shifting by forcing coal- and natural-gas plants to shut down or shift generation to cleaner inputs. What is more, the Proposed Rule presupposes that power plants will be able to implement several new technologies based on "crystal ball" predictions as to their availability and technical feasibility.[5] In doing all this, the EPA again sets out to accomplish what the Supreme Court said it could not without clear congressional authorization: restructure the nation's mix of energy generation.[6]

What is more, the EPA further asserts unheralded power over aspects of the power-generation process—specifically, hydrogen-fuel manufacturing—that it lacks authority to regulate. The Proposed Rule not only demands that power plants substitute large amounts of hydrogen fuel for natural gas, but also demands that the fuel be produced through processes that generate low, or no, greenhouse-gas emissions. But hydrogen burns just the same whether it was obtained through a "clean" or "dirty" process. Tellingly, the EPA offers no justification for this authority to demand emissions reductions beyond the sources that it is authorized to regulate under Section 111. That is because it has no such authority; if Congress had conferred upon the EPA the "unheralded power" to control the end-to-end production of power for the country, it would have given "clear congressional authorization" to do so.[7] Congress gave no such authorization.

---

[2] 42 U. S. C. §7411.

[3] 42 U. S. C. §§7408-7410.

[4] *Compare* New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33240, 33243 (May 23, 2023) with Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64662, 64784 (Oct. 23, 2015).

[5] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (quotation omitted).

[6] *West Virginia v. EPA*, 142 S. Ct. 2587, 2610–16 (2022).

[7] *Id.* at 2609 (quoting *Utility Air Regulatory Group v. EPA*, 573 U. S. 302, 324 (2014)); *see Biden v. Nebraska*, 600 U.S. ___, 2023 WL 4277210 *3 (2023).

All told, the EPA lacks authority to order such a vast restructuring of the nation's mix of energy generation. The Proposed Rule will touch all aspects of American life. It will cost tens of billions of dollars; eliminate thousands of jobs at hundreds of power plants and related industries; affect the reliability of the power grid; and alter energy prices for millions of commercial and residential consumers. Our Constitution leaves decisions like this—decisions of "vast economic and political significance"—to Congress.[8] At the very least, no agency can make such decisions without clear authorization from Congress. Neither the New Source Performance Standards program nor anything else in the Clean Air Act is susceptible of being read to confer such massive authority upon the EPA.

In light of these and other problems, the EPA should withdraw the Proposed Rule.

I. The Proposed Rule relies on inadequately demonstrated technology.

The Proposed Rule is unlawful because it relies on technologies—specifically, carbon capture and sequestration, along with high levels of co-firing—that have not been "adequately demonstrated."[9] Retrofitting these technologies to existing sources will be infeasible, if not impossible. Thus, there is no way to achieve the proposed emissions reductions through the implementation of these inadequately demonstrated technologies.

A. Carbon Capture and Sequestration.

First, the Proposed Rule asks power plants to implement a largely untested technology: carbon capture and sequestration. Carbon-capture-and-sequestration technology, as its name indicates, permits power plants to capture and permanently store CO_2 emissions.[10] Successful capture and sequestration has three major components: CO_2 capture, transportation, and underground storage.[11] The Proposed Rule determines that the best system of emissions reductions for three groups of power plants—new (and modified) natural-gas and coal-fired power plants and existing long-term coal-fired plants—includes capturing and sequestering 90% of carbon emissions.[12] But, carbon capture and sequestration at this very high rate is not technically feasible.

---

[8] *Utility Air*, 573 U. S. at 324 (quotation omitted).
[9] *See* §7411(a)(1).
[10] 88 Fed. Reg. at 33254.
[11] *Id.*
[12] *Id.* at 33277, 33303, 33335, 33351.

To provide an illustration of why the EPA overstates the feasibility of carbon capture at a 90% rate, consider SaskPower's Boundary Dam Unit 3, a coal-fired unit retrofitted with carbon-capture-and-sequestration technology in Saskatchewan, Canada. The EPA touts this unit as having "achieved CO_2 capture rates of 90%."[13] But this facility is the *world's* only operating commercial carbon capture facility at a coal-fired power plant.[14] And it has never achieved its maximum capacity.[15] It also battled significant technical issues throughout 2021—to the point that the plant idled the equipment for weeks at a time.[16] As a result, the plant achieved less than 37% carbon capture that year despite having an official target of 90% (which is the target set for newly modified and existing coal-fired plants by the Proposed Rule).[17]

These technical failures are not unique to SaskPower. A study of 263 carbon-capture-and-sequestration projects undertaken between 1995 and 2018 found that the majority failed and 78% of the largest projects were cancelled or put on hold.[18] After the study was published in May 2021, the only other coal plant with a carbon-capture-and-sequestration attachment in the world, Petra Nova, shuttered after facing 367 outages in its three years of operation. That plant fell short of its emissions reduction goals by 17%. In the EPA's less-than handful of examples touting the success of carbon capture and sequestration, the agency points to two domestic coal-fired plants, for example[19]—but even those plants have implemented only the capture component of carbon-capture-and-sequestration.[20]

Even if carbon capture on the order of 90% is possible, there is yet another roadblock to successfully executing carbon capture and sequestration at the levels contemplated in the Proposed Rule: sequestration. As the EPA admits, CO_2 sequestration is not so much a "technology" but rather a hypothesis. The EPA asserts the "effectiveness of long-term trapping of CO_2" because it has observed CO_2 being naturally

[13] 88 Fed. Reg. at 33254.
[14] *Only still-operating carbon capture project battled technical issues in 2021*, S&P Global Market Intelligence, (Jan. 6, 2022), available at https://perma.cc/BMB6-BS37
[15] *Id.*
[16] *Id.*
[17] *Id.*
[18] *The World's Only Coal Carbon Capture Plant Is Regularly Breaking*, Vice, (Jan. 11, 2022), *available at* https://perma.cc/6MJA-FMTJ.
[19] 88 Fed. Reg. at 33254.
[20] *Id.* at 333291–92.

trapped in rock formations "for millions of years."[21] This is hardly a "demonstration" of sequestration, much less an adequate one. Natural sequestration is not the same as intentional CO_2 injection into the Earth. It is telling, moreover, that the EPA does not point to a single example where controlled injection of captured carbon emissions has been successful on the scale required to sequester 90% of carbon captured at a large-scale power plant.[22] Moreover, the examples it does provide do not compare to the circumstances of plants in Ohio. For example, two of the EPA's examples of successful sequestration are located in Norway.[23] Plants in Norway, however, have easy access to offshore sites. That makes transportation of captured carbon dioxide and sequestration under the ocean technologically feasible and substantially more cost effective.

Coal plants located in Ohio and most other States will not have the same easy access to offshore sites. Existing coal- and natural-gas-fired power plants are geographically constrained. They cannot relocate to be closer to sequestration sites, which means that the transport of CO_2, even if it can be accomplished successfully (which is itself doubtful), will be prohibitively expensive to implement owing to the plants' distance from traditional offshore sequestration sites.

Putting this all together, unless the ideal geology is already present beneath an existing power plant, the plant cannot sequester its captured emissions without constructing pipeline and sequestration infrastructure. Ohio plants currently in operation neither have this unique geological luck, nor do they have the infrastructure for transport or injection underground or a market for the development of that infrastructure. The same goes for plants in other States across the country. Successful sequestration is precisely the kind of "purely theoretical or experimental" technology that cannot be deemed "adequately demonstrated."[24]

B. Retrofitting existing plants for co-firing.

The Proposed Rule also requires plants to "co-fire" cleaner inputs—that is, to substitute a cleaner energy input in lieu of the one currently being fired.[25] For instance, in a coal-fired power plant, natural-gas co-firing is the substitution of natural gas for

[21] *Id.* at 33295.
[22] *See id.*
[23] *Id.*
[24] *Portland Cement Ass'n*, 486 F.2d at 391.
[25] 88 Fed. Reg. at 33254.

some of the coal input so that the unit fires a combination of coal and natural gas.[26] The Proposed Rule demands co-firing at extremely high levels. Some existing coal-fired power plants must co-fire up to 40% of their input with natural gas.[27] And, natural-gas plants, both existing and new, must co-fire up to 96% (nearly all) of their inputs with hydrogen manufactured through a process that produces little to no greenhouse gas emissions (also called "low-GHG hydrogen").[28]

These co-firing requirements at such high levels are onerous on all power plants. But they will be prohibitively costly for existing power plants. Existing coal plants will have to install significant infrastructure, such as new gas burners and related boiler modifications. And they will have to construct natural gas pipelines to supply natural gas for co-firing purposes. But, redirecting or building new natural-gas pipelines to where the coal plants are currently located is hardly feasible and likely impossible. Further, existing natural-gas plants must undergo similar, costly modifications to achieve hydrogen-co-firing compatibility. And obtaining nearly 100% levels of low-greenhouse-gas hydrogen, which is hard to obtain, is unlikely to come to fruition.

What is more, co-firing compatibility is not adequately demonstrated. The EPA notes that "[m]any models of *new* utility combustion turbines have demonstrated the ability to co-fire up to 30 percent hydrogen," and that "developers are working toward models that will be ready to combust 100 percent hydrogen by 2030."[29] This is hardly the kind of demonstration that justifies forcing *existing* natural-gas plants to convert to co-firing hydrogen at 96% levels the Proposed Rule contemplates. For one thing, the only demonstration of hydrogen co-firing that the Proposed Rule touts has been achieved in *new* combustion turbines—and only at the 30% rate. Consider also two of the examples of hydrogen-co-firing retrofits on existing natural-gas-fired plants.[30] One was capable of co-firing 5% hydrogen and the other, 20%.[31] These are nowhere near the optimistic levels contemplated in the Proposed Rule. It is not enough that the EPA point to a "test burn" at 80% hydrogen-substitution levels to justify placing these burdens on all plants.[32] Thus even if hydrogen co-firing at very high levels could be feasible for new plants, it is doubtful that it can be accomplished

---

[26] *Id.*
[27] *Id.* at 33337–38.
[28] *Id.* at 33361.
[29] *Id.* at 33255.
[30] *Id.* at 33364.
[31] *Id.*
[32] *Id.*

by existing natural-gas plants at the levels and in the timeline contemplated by the rule.

C. Procuring Low-greenhouse-gas Hydrogen.

The EPA makes one more "crystal ball" prediction:[33] that natural-gas power plants will be able to procure massive quantities of hydrogen manufactured through a low-greenhouse-gas process in the time frame set by the Proposed Rule. Remember, low-greenhouse-gas hydrogen refers to the manufacturing process that produces hydrogen, not to the chemical composition of the hydrogen itself.[34] Power plants must now seek out vendors that sell hydrogen manufactured through this clean process. Such vendors are few and far between, largely because of the technical- and cost-barriers of producing clean hydrogen.

II. The EPA exceeds its Section-111 Authority by regulating the means by which hydrogen is being procured for co-firing.

The EPA does not have authority to dictate the manufacturing process by which hydrogen is obtained for co-firing. But, by forcing existing and new natural-gas-fired power plants to co-fire low-greenhouse-gas hydrogen,[35] that is exactly what the EPA unlawfully does. Some technical background is helpful here. Hydrogen is a clean fuel, which means that burning it does not emit CO_2.[36] But some of the processes used to produce hydrogen fuel does generate CO_2.[37] For instance, the most common way of obtaining hydrogen fuel is by splitting natural gas into hydrogen and CO_2.[38] But this process produces significant carbon emissions and does little to offset the emissions saved by burning hydrogen for power. The greenest method of producing hydrogen involves splitting water into hydrogen and oxygen through electrolysis conducted using renewable energy.[39] And, because hydrogen obtained through a high-greenhouse-gas process is indistinguishable from hydrogen obtained through a low-greenhouse-gas process, the EPA suggests that it may seek "independent third-party verification" "to ensure that the low-GHG hydrogen used by" power plants

[33] *Portland Cement Ass'n*, 486 F.2d at 391 (citation omitted).
[34] 88 Fed. Reg. at 33255.
[35] *Id.* at 33366; *id.* at 33331.
[36] *Id.* at 33255.
[37] *Id.*
[38] Zurich Insurance Group, *What are green hydrogen and blue hydrogen, and can they solve the climate crisis?* (Jan. 13, 2023), available at https://perma.cc/DF34-HSAK.
[39] *Id.*

"is actually low-GHG, and" to "guard against [the] use of hydrogen that is falsely claimed to be low-GHG hydrogen."[40]

Somewhat glaringly, the EPA provides no authority to justify regulating fuel-manufacturing processes under Section 111. That is because it does not have the authority to impose these beyond-the-source regulations. True, the agency notes that "tax credits" in the Inflation Reduction Act[41] will "incentivize the manufacture of hydrogen through low GHG-emitting methods" and will "fuel[] interest in co-firing hydrogen."[42] But such incentive schemes do not give *the EPA* regulatory authority to regulate the production of hydrogen.

Surely Section 111 does not give the EPA the power it claims. That section empowers the EPA to enact only "efficiency-improving, at-the-source measures."[43] Regulating the hydrogen-manufacturing process is neither efficiency improving nor an at-the-source measure. By the EPA's own concession, whether hydrogen is produced through a high-greenhouse-gas or low-greenhouse-gas method has no impact on its efficiency as a fuel substitute—in other words, the manner in which hydrogen is produced has no bearing on how well it will improve efficiency at the source where it is used. Hydrogen burns just the same at each source, regardless of whether it was obtained through a "clean" or "dirty" process. And the hydrogen-manufacturing process falls outside of the purview and scope of the regulated power plants, generally. Indeed, the statute permits the EPA to set standards of performance for new and existing "*sources*," and not their vendors.[44] Thus, the EPA does not have the authority to enact such beyond-the-source regulations that have no impact on the efficiency of emissions reductions by each source.

The EPA's assertion of this dramatic and unjustified authority runs afoul of the major-questions doctrine. If the EPA has the authority to regulate beyond the regulated source, where does that authority end? Can the EPA demand under its Section-111 authority that a regulated source's employees use only electric vehicles on their way to work? "[C]ommon sense" would suggest otherwise.[45] If Congress had conferred upon the EPA the "unheralded power" to control the end-to-end production of

---

[40] 88 Fed. Reg. at 33331.
[41] Pub. L. 117–169, 136 Stat. 1818 (2022).
[42] 88 Fed. Reg at 33246.
[43] *West Virginia*, 142 S. Ct. at 2612 n.3.
[44] §§7411(b)(1)(B), (d)(1).
[45] *West Virginia*, 142 S. Ct. at 2609 (quotation omitted); *Biden*, 600 U.S. ___, 2023 WL 4277210 at *17 (Barrett, J., concurring).

power for the country, it would have given "clear congressional authorization" to do so.[46] Congress has not authorized the EPA, clearly or otherwise, to regulate in this area.

III. The Proposed Rule unlawfully restructures the current mix of energy generation.

Under Section 111(d), the EPA may regulate emissions from existing sources by imposing standards of performance based on targeted, achievable "measures that would reduce pollution by causing the regulated source to operate more cleanly."[47] These measures must involve at-the-source implementation of "efficiency improvements, fuel-switching," "add-on controls," and other "traditional air pollution control measures."[48] What the EPA may not do through Section 111—a quintessential "gap-fill[ing]" provision[49]—is restructure "the Nation's overall mix of electricity generation."[50] Agencies cannot take such decisions of vast "economic and political significance" without "clear congressional authorization."[51] On this basis, the Supreme Court, just last year, found that the EPA had exceeded its Section 111 authority by ordering a nationwide shift from 38% coal-based electricity generation to 27% coal-based electricity generation.[52] The EPA cannot "bring about the same result" of generation-shifting through at-the-source measures "by, for example, simply requiring coal plants to become natural gas plants."[53] Although the EPA has "never ordered anything remotely likely that" before now, the nation's high court already cast "doubt" on the EPA's authority to do so.[54]

But that is what the EPA seeks to do here. In the Proposed Rule, the EPA purports to set performance standards for new coal- and natural-gas-fired power plants under its section 111(b) (§7411) authority. That, in turn, triggers the EPA's Section-111(d) authority to regulate coal- and natural-gas plants that are currently in operation. Wielding this authority, the EPA again tries to force existing coal and natural-gas

[46] *West Virginia*, 142 S. Ct. at 2608–09 (quoting *Utility Air*, 573 U. S. at 324); *see Biden*, 600 U.S. ___, 2023 WL 4277210 at *15.
[47] *West Virginia*, 142 S. Ct. at 2610–11 (quoting 80 Fed. Reg. 64726).
[48] *Id.* at 2610–11 (quoting 80 Fed. Reg. 64784).
[49] *Id.* at 2610.
[50] *Id.* at 2607.
[51] *Id.* at 2609–16 (quotations omitted).
[52] *Id.* at 2607, 2616.
[53] *Id.* at 2612 n.3.
[54] *Id.*

plants to "'shift' away virtually all of their generation, that is, cease making power altogether."[55] This time, however, it does so with at-the-source shifting requirements: coal-plants must adopt either carbon capture and sequestration at a 90% rate, or substitute nearly half of their input with natural gas, while natural-gas plants must substitute almost all of their input with (hard to obtain) low-greenhouse-gas hydrogen.

At the levels imposed by the Proposed Rule, these at-the-source measures in aggregate entail nationwide generation shifting. Through the Proposed Rule, the nation's mix of energy generation will shift more significantly than it would have under the now-defunct Clean Power Plan. The Supreme Court already rejected the EPA's claimed authority to restructure the nation's power industry in this way.[56] The EPA should withdraw the Proposed Rule before it is struck down again.

A. Proposed regulation of existing coal- and natural-gas-fired power plants.

Because the Proposed Rule takes a complex, at-the-source approach to shifting power generation in existing sources, this letter first provides some background on the Proposed Rule's requirements for existing sources. Under the Proposed Rule, the EPA will regulate two categories of power plants under its Section 111(d) authority: fossil-fuel-fired electric steam generating units—which are mostly coal-fired—and natural-gas-fired stationary combustion turbines. This letter describes the requirements the Proposed Rule would impose on each category of existing source.

1. Fossil-fuel-fired electric steam generating units

The EPA first proposes standards of performance for fossil-fuel-fired electric steam generating units, which are largely coal-fired. The Proposed Rule these units into two groups: coal-fired plants on the one hand, and oil- and gas-fired plants on the other. The EPA further subcategorizes coal-fired plants into groups based on whether, and when, the power plants have committed to cease operations in the future: long-term, medium-term, near-term, and imminent-term.[57] Altogether, this gives rise to five groups of power plants: the four categories of coal-fired plans, plus oil- and gas-fired plants.

---

[55] *West Virginia*, 142 S. Ct. at 2612.
[56] *Id.*
[57] 88 Fed. Reg. at 33341–60.

The first group—long-term coal-fired plants—are coal-fired power plants that have not committed to permanently ceasing operations by 2040.[58] For this category, the EPA determined that the best system of emissions reduction would be carbon capture and sequestration that achieves 90% capture of CO_2. (The proposed rule and many cases refer to the "best system of emissions reduction" using the acronym "BSER." This letter will do the same.) The standard of performance that coal-fired plants in this category must achieve by 2030 is an 88.4% reduction in greenhouse-gas emissions from each plant's current emissions level.[59]

The second group—medium-term coal-fired plants—are those that have committed to permanently ceasing operations after 2031 and before 2040, and that have not taken any capacity restrictions.[60] For this category, the Proposed Rule determines that the BSER is co-firing natural gas at 40% "of the heat input to the unit"—that is "substitut[ing] ... natural gas for" 40% "of the coal" as an input.[61] The standard of performance that coal-fired plants in this category must achieve by 2030 is a 16% reduction in greenhouse-gas emissions from each plant's current emissions level.[62]

The third and fourth groups, respectively, are coal-fired power plants slated to shut down before 2035 (and that have opted to function at only 20% capacity) and those that will shut down before 2032. Those coal-fired plants are to continue "routine methods of operation" and maintain the emissions rate at which they currently operate until they close in the near term.[63]

Finally, the remaining small number of non-coal-fired electric steam generating units are similarly capped at their current emissions rate and must continue "routine methods of operation and maintenance" or are not subject to regulation under this Rule at all.[64]

---

[58] *Id.* at 33359, Table 5.
[59] *Id.*
[60] *Id.*
[61] *Id.*; *see also id.* at 33251 (defining co-firing).
[62] *Id.* at 33359, Table 5.
[63] *Id.*
[64] *Id.* at 33359–60, Table 5.

2. Fossil-fuel-fired stationary combustion engines

The Proposed Rule also regulates the existing fleet of fossil-fuel-fired stationary combustion engines. These are natural-gas fired power plants. Recognizing that the "large size of the existing" natural-gas-fired "fleet" needs "lead time required to develop" and "appl[y]" the BSER technology and supporting infrastructure, the Proposed Rule focuses only on the largest and most frequently operated existing natural-gas plants that emit the most greenhouse-gas emissions in this category. [65] The EPA committed to subsequent rulemaking addressing the smaller natural-gas plants.[66]

The Proposed Rule sets performance standards for natural-gas plants that run at or over a 50% capacity factor—that is, plants that generate over 50% of its theoretical maximum capacity of electricity generation—and which have a capacity size of 300MW or greater.[67] These plants represent about 20% of the total power generated by this category.[68] But, the EPA is contemplating inclusion of natural-gas plants that generate over 200MW (which would affect about 51% of the total capacity and generation of units in this category) and over 100MW which would encompass *all* units in this category.[69]

Nevertheless, for natural-gas plants that have a capacity to produce over 300MW and that run at or over a 50% capacity, the Proposed Rule requires either carbon capture and sequestration at the 90% rate by 2035 *or* co-firing hydrogen (obtained through processes that emit low greenhouse-gass) in the amounts of 30% by 2032 and 96% by 2038 (by volume).[70]

Rather than take the usual next step of setting emissions limits based on the implementation of the identified BSER, the EPA takes the unusual step of estimating the "extent of reductions in CO_2 emissions" possible under either the carbon-capture-and-sequestration approach or the low-greenhouse-gas hydrogen co-firing approach. With the carbon capture and sequestration of 90% approach, the EPA estimates emissions reductions anywhere from 88.7% to 89.3%.[71] With the hydrogen co-firing

[65] *Id.* at 33361.
[66] *Id.*
[67] *Id.*
[68] *Id.* at 33363, Table 6.
[69] *Id.* at 33362, 33363, Table 6.
[70] *Id.* at 33363.
[71] *Id.* at 33369.

approach, the EPA estimates 90% reduction in emissions by co-firing at the 96% level.[72] The Proposed Rule does not set an emissions level that the plants must meet.

B. The EPA greatly exceeds its Section-111(d) authority by restructuring the current mix of energy generation.

The EPA has already lost once in its attempt to restructure the nation's power generation. The Clean Power Plan that the Supreme Court rejected in *West Virginia* was straightforward in its intention: shift the nation's power generation from 38% to 27% coal-fired power.[73] The Proposed Rule is not as straightforward, but ultimately does the same, albeit disguised as efficiency-improving, at-the-source measures. Just like the Clean Power Plan, the Proposed Rule will impact the nation's power supply, eliminate thousands of jobs in the power and related industries, and force industry and consumers to pay billions of dollars to achieve the EPA's policy preference for less fossil-fuel-based power generation. The Supreme Court already stopped the EPA from exerting such massive authority over the nation's power industry once.[74] It is likely to do so again if the Proposed Rule is not withdrawn.

To understand why this Rule runs afoul of the limited authority granted by Congress, consider what the at-the-source measures, applied in aggregate to all existing power plants, actually do. For the reasons stated above, carbon capture and sequestration at a 90% capture rate cannot be accomplished by existing power plants. Yet, the Proposed Rule gives long-term coal-fired plants—that is, plants with the greatest remaining useful life, which form the nation's baseload of electricity generation—no option but to accomplish the impossible within seven years.[75] Those plants will close.

The remaining medium-term coal-fired plants (which also form a significant part of the nation's base load) must co-fire 40% of their input with natural gas.[76] Co-firing at these levels is generation shifting by a different name. By 2030, the Proposed Rule requires each medium-term plant to "simply … become"[77] almost half natural-gas plants. Combined with the fact that many smaller coal-fired plants have already

[72] *Id.* at 33366.
[73] *West Virginia*, 142 S. Ct. at 2604.
[74] *Id.* at 2616.
[75] *See* 88 Fed. Reg. at 33349 (compliance deadline for implementing carbon capture and storage for affected units is January 1, 2030).
[76] *Id.* at 33351.
[77] *West Virginia*, 142 S. Ct. at 2612 n.3.

committed to imminent or near-term closure, this Rule in aggregate creates a dramatic shift away from coal to sources that the EPA, in its judgment alone, deems better for the nation's energy generation.

Natural-gas plants are put to the same test. Here, however, the Proposed Rule gives them options: either retrofit technically infeasible carbon-capture-and-sequestration technology or co-fire hydrogen at a near-hundred-percent level. In other words, the EPA directs natural-gas plants to adopt technology that is unlikely to work or, more "simply," "become"[78] hydrogen plants. And the Proposed Rule, as of now, requires this shift to almost-full hydrogen-based generation for at least 20% of the existing natural-gas fleet by generation capacity.[79] That is a *much larger* impact than the 11% shift out of coal to cleaner sources in the CPP that the Supreme Court determined was unlawful. Through these at-the-source measures, aggregated nationwide, the EPA will do what the Court said it could not under its Section 111(d) authority: "dictat[e] the optimal mix of energy sources nationwide."[80]

Whether by design or through neglect, the EPA does not explain how large a shift the Proposed Rule will cause from coal to natural gas and natural gas to hydrogen. But other indicia confirm that this is the sort of "at-the-source measures" aimed at generation shifting that the Supreme Court doubted the EPA had authority to enact.[81] Because the standards of performance for existing coal-fired power plants are percentage reductions of emissions relative to the source's current baseline, while the standards of performance for new coal-fired power plants are numerical caps,[82] the Proposed Rule does not allow meaningful comparison between the performance standards for new and existing coal plants. That is legally significant: the Supreme Court has inferred that stricter emissions caps for existing sources than those for new sources is indicative of an attempt to force existing sources out of production completely.[83] What sort of nationwide shift will the Proposed Rule will effectuate? The EPA offers no answer. Its failure to do so is arbitrary and capricious.

What is more, the EPA does not set any standard of performance at all for natural-gas plants—numerical, percentage reduction, or otherwise. It simply assumes that

---

[78] *Id.*
[79] *See* 88 Fed. Reg. at 33363, Table 6.
[80] *West Virginia*, 142 S. Ct. at 2613.
[81] *Id.* at 2612 n.3.
[82] *Compare* 88 Fed. Reg. at 33359 *with id.* at 33322–33326.
[83] *West Virginia*, 142 S.Ct. at 2604.

the plants will pick one of the identified BSERs and estimates that they will end up reducing its emissions, relative to the baseline, by about 90%. In other words, natural-gas plants can comply with the rule only by adopting one or the other BSER—adopting another technology that achieves the same (or better) level of emission reduction will not suffice.

By eschewing a set standard of performance for natural-gas plants, the EPA falls short of fulfilling, and also contradicts, its role under Section 111(d). Remember, once an emissions cap is set, a source "may achieve that emissions cap any way it chooses" as long as "its pollution [is] no more than the amount 'achievable through the application of the best system of emission reduction."[84] In other words, the EPA may not dictate *how* the source will achieve a particular cap, just what those targets are. Indeed, if Congress had intended to grant the EPA authority to simply dictate the technical measures stationary sources must adopt, it would have stopped at granting the EPA the authority to set the BSER for covered stationary sources, and would not have not required the EPA to take the next step to set standards of performance *based on* the BSER identified by the EPA. Under the Proposed Rule, however, existing natural gas plants have no set emissions ceiling. Rather they have three options: either implement carbon capture and sequestration, shift generation to hydrogen inputs, or shut down. Put another way, the EPA falls short of its Section 111(d) obligation by failing to set standards of emissions after identifying the BSER. Because many of the "existing" natural-gas plants must shift to firing low-greenhouse-gas hydrogen, the only somewhat-technically feasible BSER, their only true options are either to "effectively cease to exist" or to become hydrogen-fired power plants.[85]

The net result is clear. After trying and failing to set an overarching, nationwide generation-shifting scheme, the EPA now "forc[es] a shift throughout the power grid from one type of energy source to another" by putting the most productive power plants to a Hobson's choice: close or transition.[86] But that is precisely what the Supreme Court already considered and rejected. The EPA may not "bring about the same result" of restructuring the nation's mix of energy generation "by, for example, simply requiring coal plants to become natural gas plants," or natural-gas plants to simply become hydrogen plants through the imposition of "efficiency-improving, at-the-source measures."[87]

---

[84] *Id.* at 2601(quoting §7411(a)(1)).
[85] *Id.* at 2612 n.3.
[86] *Id.* at 2611–12.
[87] *Id.* at 2612 n.3.

How much coal- and natural-gas based generation there should be over the next two decades is a policy question of great "magnitude and consequence." Without clear delegation from Congress, the EPA is without authority to make that decision for the nation. [88]

IV. The cost-benefit analysis supporting the Proposed Rule is flawed.

The EPA must "tak[e] into account the cost of achieving" emissions reductions "and any nonair quality health and environmental impact and energy requirements" in any rulemaking undertaken pursuant to Section 111.[89] The EPA's cost-benefit analysis supporting this Rule rests on erroneous assumptions and is underdeveloped in parts. When an agency relies "on a cost benefit analysis as part of its rule-making," such "serious flaw[s] undermining that analysis can render the rule unreasonable." [90]

A. The cost-benefit analysis considers factors that Congress did not intend for the EPA to consider.

The EPA relies on the flawed social cost of carbon metric to measure the alleged benefits of the Proposed Rule.[91] This "SC-CO_2" allegedly represents "monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase."[92] It "includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services."[93] Factors such as "risk of conflict," "environmental migration," and "property damage" are included in the social cost of carbon,[94] but are well outside the "nonair health and environmental impacts and energy requirements" that Congress authorized the EPA to consider in setting standards of performance under Section 111.[95] Inflating the

[88] *Id.* at 2616.
[89] §7411(a)(1).
[90] *National Ass'n of Home Builders v. EPA*, 682 F.3d 1032, 1040 (D.C. Cir. 2012).
[91] 88 Fed Reg. at 33411-12.
[92] *Id.* at 33411.
[93] *Id.*
[94] *Id.*
[95] *See* §7411(a)(1).

benefits of the Proposed Rule by including such factors that Congress did not intend is arbitrary and capricious.[96]

B. The cost-benefit analysis contradicts the requirements of Section 111.

The EPA's cost-benefit analysis is separately flawed because it does not separate the Proposed Rule's impact on new sources with that on existing sources. For reasons the EPA does not explain, it groups together the costs and benefits associated with both existing and new sources without delineating which costs and benefits are attributed to the Proposed Rule's impact on which sources.[97] This approach is both contrary to the Section 111's requirements and is arbitrary and capricious.

Section 111 requires that regulations on new sources be independently justified from those on existing sources. That is because Section 111's two-step regulatory process is linear: the authority to regulate existing sources is triggered only after the EPA sets standards of performance for new sources "taking into account the cost of achieving" such emissions reductions from new sources "and any nonair quality health and environmental impact and energy requirements" thereof.[98] The standards of performance for new sources thus cannot include the costs and benefits justifying the *yet-undetermined* standards of performance for existing sources. It follows that subsequent rulemaking process for *existing* sources cannot double dip by including in it the benefits of regulating new sources. Indeed it is telling that in a prior rulemaking to reduce greenhouse-gas emissions under its authority to set New Source Performance Standards, the EPA did the cost-benefit analysis twice-over—once for the new-source regulation that was limited to the costs and benefits associated with regulating new sources,[99] and once for the existing-source regulation limited to the costs and benefits of regulating the existing sources.[100]

This unlawful mixing and matching has serious implications. It frustrates any meaningful examination of the costs and benefits associated with regulating new sources and those associated with existing sources. This is especially so when the technical considerations of, and approaches to, setting standards for new and existing sources

[96] *Motor Vehicle Mfrs. Ass'n v. State Farm*, 463 U.S. 29, 43 (1983).
[97] 88 Fed. Reg. at 33416-17.
[98] §7411(a)(1), (d); *see also West Virginia*, 142 S. Ct. at 2601.
[99] Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64510, 64640–64642 (Oct. 23, 2015)
[100] 80 Fed. Reg. at 64924–64933.

are night and day. As an example, implementing carbon capture and sequestration at a 90% capture rate in existing sources involves different technical considerations and therefore a different cost-benefit calculus than that used for new sources. To name just one difference that has serious cost implications, new power plants may have some geographical flexibility to consider locating near sequestration sites, while existing power plants have none. That means that the costs associated with transport and sequestration of 90% carbon capture for a new source and for an existing source will dramatically differ.

In sum, the EPA does not give any reason for why its mix-and-match cost-benefit analysis is lawful or even helpful. Indeed, it does not give any reason at all for splitting the analysis in this way. Thus this cost-benefit analysis is contrary to law, meaningless, and the decision to take a mix-and-match approach is arbitrary and capricious.

C. The net benefits are erroneously and unlawfully inflated to emphasize benefits over costs.

The cost-benefit analysis is also flawed because it unreasonably inflates the benefits over the costs through creative accounting methods. Cost-benefit analyses are sensitive to discount factors and so can be manipulated easily by creative accounting methods. The EPA leans on that. Citing "special ethical considerations" that "arise when comparing benefits and costs across generations," the EPA discounts climate benefits at a lower discount rate of 3% and combines it with health benefits and costs discounted at a higher 7% rate. The EPA's use of a lower discount rate to compute benefits and a higher one to compute costs ensures that the putative benefits of regulation always outweigh the costs. Moreover, discounting benefits at a 3% rate and costs at a 7% rate lacks economic sense. Worse, it contradicts the Office of Management and Budget's own methodology which suggests that cost-benefits analyses may appropriately "discount future costs and consumption benefits," *both*, "at a lower rate than for intragenerational analysis."[101] Thus, even if using a lower discount value is appropriate for intergenerational regulatory analysis—a dubious proposition in itself—nowhere does the Office of Management and Budget suggest that it is

[101] *See* Office of Management and Budget, Circular A-4 at 33–36 (Sept. 17, 2003) *available at* https://perma.cc/D9XW-F8QQ.

appropriate to inflate benefits over costs by applying a significantly lower discount rate to one and not the other.[102]

D. The EPA cannot base its authority to regulate greenhouse-gas emissions on the basis of health benefits that are not attributable to reductions in greenhouse-gases.

The cost-benefit analysis further inflates the benefits associated with the Proposed Rule with benefits unrelated to reductions in greenhouse-gas emissions. The EPA does not have authority under Section 111 to include the benefits of reducing other pollutants, especially pollutants regulated under another section of the Clean Air Act.

Under Section 111, the EPA must regulate sources on a "pollutant-by-pollutant basis."[103] Consistent with that approach, the EPA has always performed a pollutant-focused analysis: it identifies a pollutant that will endanger public health or welfare; next, it identifies major sources of that pollutant; and finally, it sets standards of performance aimed at reducing emissions *of those* pollutants.[104] At the final step, the EPA may account only for "the cost of achieving *such* reduction and any nonair quality health and environmental impact and energy requirements."[105] The final step thus is pollutant focused: incidental reductions in emissions of other pollutants do not matter.

This is further confirmed by Section 111(d), which forbids the EPA from imposing on existing sources controls for pollutants that are *already* being regulated under the NAAQS or HAP programs.[106] Because the EPA does not have authority to regulate under Section 111(d) pollutants that are regulated under other sections of the Clean Air Act, it cannot include, as justification for rulemaking under Section 111(d), incidental reductions in emissions of those prohibited pollutants. To allow otherwise would effectively permit an end run around Section 111(d)'s limited grant of authority. In other words, the EPA could regulate indirectly any pollutant under 111(d) even though Congress expressly barred it from doing so.

[102] *Id.* at 35-36; *see also id.* at 34 ("[F]uture health effects, including both benefits and costs, should be discounted at the same rate.").
[103] *West Virginia*, 142 S. Ct. at 2601.
[104] *Id.* at 2602 (citing examples).
[105] §7411(a)(1) (emphasis added).
[106] §7411(d)(1).

Thus the EPA cannot justify regulating greenhouse-gas emissions under Section 111 with reference to ancillary health benefits wholly attributable to reductions in emissions of pollutants *other than* greenhouse-gases. And it especially cannot do so where, as here, those co-benefits stem from reductions of criteria pollutants—NO_x, SO_x, and $PM_{2.5}$—that are regulated under a completely different Clean Air Act program: the NAAQS program.[107]

True, the benefits stemming from reductions in GHG, even excluding the co-benefits, outweigh the costs by the EPA's estimation.[108] That makes the inclusion of co-benefits even more puzzling. Even if the EPA could account for incidental co-benefits of reductions in non-greenhouse-gases, those co-benefits are unreasonably disproportionate to the benefits actually stemming from reductions in greenhouse-gases. The EPA calculates that health benefits account for $68 billion of the benefits.[109] That is over twice the estimated $30 billion of climate benefits attributable to reductions in greenhouse-gas emissions.[110] And it accounts for over half of the benefits attributable to the Proposed Rule.[111] This outsized representation of co-benefits attributable to reductions in *non-greenhouse-gas* emissions cannot justify the EPA's decision to impose billions of dollars of costs on new and existing power plants to reduce greenhouse-gas emissions.

[107] *Criteria Air Pollutants*, United States Environmental Protection Agency, (August 9, 2022), *available at* https://perma.cc/CFT8-77GE.
[108] 88 Fed. Reg. at 33416, Table 10
[109] *Id.*
[110] *Id.*
[111] *Id.*

* * *

The EPA exceeds its Section-111(d) authority by imposing at-the-source measures to shut down coal- and natural-gas plants or shift them away from coal- and natural-gas based energy generation. This Rule will force power plants to adopt unproven technologies that are technically infeasible or shut down. Many will shut down. As a result, an already stretched-thin electric grid will become more unreliable.[112] This is the sort of nationwide generation-shifting that the Supreme Court has already held that the EPA lacks the authority to order. And the EPA asserts unheralded power over more aspects of the power-generation process than ever before by asserting limitless authority over manufacturing processes ancillary to the traditional at-the-source efficiency-improvements that it is authorized to impose. All this means one thing: the EPA should withdraw its Proposed Rule now, so that the States and other parties do not have to secure a judicial order vacating it later.

Yours,

Dave Yost

DAVE YOST
Attorney General
State of Ohio

[112] *See* PJM Interconnection, *Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Feb. 24, 2023), *available at* https://perma.cc/2NQZ-C2W5

STEVE MARSHALL
Attorney General
State of Alabama

TIM GRIFFIN
Attorney General
State of Arkansas

ASHLEY MOODY
Attorney General
State of Florida

CHRISTOPHER M. CARR
Attorney General
State of Georgia

TODD ROKITA
Attorney General
State of Indiana

KRIS KOBACH
Attorney General
State of Kansas

ANDREW BAILEY
Attorney General
State of Missouri

MIKE HILGERS
Attorney General
State of Nebraska

JOHN M. FORMELLA
Attorney General
State of New Hampshire

ALAN WILSON
Attorney General
State of South Carolina

MARTY JACKLEY
Attorney General
State of South Dakota

ANGELA COLMENERO
Provisional Attorney General
State of Texas

DANIEL CAMERON
Attorney General
Commonwealth of Kentucky

SEAN REYES
Attorney General
State of Utah

JEFF LANDRY
Attorney General
State of Louisiana

JASON MIYARES
Attorney General
Commonwealth of Virginia

LYNN FITCH
Attorney General
State of Mississippi

STATE OF TENNESSEE
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
DIVISION OF AIR POLLUTION CONTROL
William R. Snodgrass Tennessee Tower, 15th Floor
312 Rosa L. Parks Avenue
Nashville, TN 37243
(615) 532-0554 Voice or (615) 532-0614 FAX

August 7, 2023

Via Electronic Submittal
Michael S. Regan, Administrator
U. S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Re: Tennessee Comments on Proposed New Source Performance Standards and Emission Guidelines for Greenhouse Gas Emissions From New, Modified, Reconstructed, and Existing Fossil Fuel-Fired Electric Generating Units (Docket ID No. EPA-HQ-OAR-2023-0072)

Dear Mr. Regan:

The Tennessee Department of Environment and Conservation submits the enclosed comments on EPA's proposed revisions to the new source performance standards and emission guidelines for greenhouse gas emissions from fossil fuel-fired stationary combustion turbine EGUs and fossil fuel-fired steam generating units. Tennessee appreciates the opportunity to comment on EPA's proposal.

Sincerely,

Michelle W. Owenby

Michelle Walker Owenby
Director, Division of Air Pollution Control
Tennessee Department of Environment & Conservation

Tennessee Comments: New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (Docket ID #EPA-HQ-OAR-2023-0072)

Section 111 of the Clean Air Act (CAA) requires the EPA Administrator to establish and periodically revise a list of categories of stationary sources, which, in the judgement of the Administrator, may reasonably be anticipated to endanger public health or welfare. Section 111(b) requires that the Administrator promulgate regulations establishing Federal standards of performance for new sources within each source category, and Section 111(d) requires that the EPA establish procedures that provide for the implementation and enforcement of standards of performance for existing sources within a source category.[1] On May 23, 2023, the EPA proposed five separate actions under Section 111, including: (1) new source performance standards (NSPS) for greenhouse gas emissions from new fossil fuel-fired stationary combustion turbine electricity generating units (EGUs); (2) NSPS for greenhouse gas emissions from modified fossil fuel-fired steam generating units; (3) emission guidelines for greenhouse gas emissions from existing fossil fuel-fired steam generating EGUs; (4) emission guidelines for GHG emissions from large stationary combustion turbines; and (5) repeal of the Affordable Clean Energy (ACE) Rule.[2]

For natural gas-fired combustion turbines and combined cycle plants, EPA proposes NSPS (**Attachment 1, Table A1-1** to these comments) based on combustion of low-GHG hydrogen (hydrogen produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen on a well-to-gate basis) and/or carbon capture and storage (CCS). For existing sources, EPA is proposing emission guidelines for gas and oil-fired combustion turbines that are comparable to the NSPS (**Attachment 1, Table A1-2** to these comments). EPA also proposes to require coal-fired steam generating units to burn 40% natural gas by volume beginning in 2032 and carbon capture and storage beginning in 2040. EPA proposes no standards for existing natural gas-fired steam generating units other than good operation and maintenance and proposes no updated NSPS for steam generating units (new coal, oil, and natural gas steam-generating EGUs would remain subject to 40 CFR 60 Subpart TTTT).

Each of the separate five actions that EPA proposes in this rulemaking could (and likely should) be the subject of separate rulemakings. Rather than comment on each of these five actions separately, these comments focus on the flaws common to four of the five proposed actions.[3] As discussed below, EPA proposes to will a nonexistent marketplace and infrastructure into being, then requires EGUs to become fully engaged participants in the Agency's vision. The proposal pushes beyond the boundary of what the best system of emission reduction under Section 111 can reasonably be. Tennessee offers the following comments on EPA's proposed NSPS and emission guidelines.

[1] 42 U.S.C. § 7411(d).
[2] *See* 88 Fed. Reg. 33240 (May 23, 2023).
[3] Tennessee is not commenting on EPA's proposed repeal of the ACE Rule in these comments.

Comment #1: EPA's Proposed Option for Low-GHG Hydrogen Has Not Been Adequately Demonstrated.

CAA section 111(a)(1) states that standards of performance for new sources must reflect "the degree of emission limitation achievable through the application of the best system of emission reduction [BSER] which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines ***has been adequately demonstrated***."[4] Similarly, CAA section 111(d) requires EPA to prescribe regulations that require each state to submit plans that establish standards of performance (which are also based on EPA's BSER) for existing stationary sources and that provide for the implementation and enforcement of those standards. The language of the federal Act is of crucial importance here, because the Act explicitly states that BSER must be based upon technology that exists not in theory, but in fact—technology that "***has been*** adequately demonstrated."[5] While EPA cites D.C. Circuit decisions allowing projection, "reasonable extrapolation," availability by a future date certain, and/or requiring a multi-year implementation process, the Agency may not simply disregard the lack of current availability. Indeed, the main case relied upon by EPA for this "reasonable extrapolation" argument also cautions that "EPA may ***not*** base its determination that a technology is adequately demonstrated . . . on ***mere speculation or conjecture***. . . ."[6] Yet that is precisely what EPA has done in this proposed rule—the Agency speculates about technologies that do not currently exist and cannot reasonably be expected to exist in a commercially feasible manner on the scale and timeline set forth in the proposed rule.

For intermediate load and baseload natural gas-fired combustion turbines, EPA proposes BSER that includes co-firing of 30% low-GHG hydrogen by volume beginning in 2032. For baseload turbines, EPA also proposes BSER to include either carbon capture and storage (CCS) by 2035 or co-firing of 96% low-GHG hydrogen by volume beginning in 2038. Furthermore, EPA proposes that hydrogen qualifies as low-GHG hydrogen if it is produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen on a well-to-gate basis, consistent with the system boundary established in Internal Revenue Code section 45V (Credit for Production of Clean Hydrogen) of the Inflation Reduction Act (IRA). EPA bases its BSER demonstration upon: (1) the availability of turbines that combust or co-fire hydrogen; and (2) the projected availability of low-GHG hydrogen as a clean fuel, as follows:

> "Many utilities and power generating companies ***have announced*** GHG reduction commitments as they further analyze and consider the incentives of the IRA. These utilities and companies ***have also announced their intention*** to permanently cease operating many of their remaining coal-fired EGUs. Some companies ***are planning*** to install combustion turbines with advanced technologies to limit GHG emissions, including CCS and hydrogen co-firing (with some companies ***having announced plans*** to ultimately move to 100 percent hydrogen firing) and advanced energy storage technologies…"[7]

---

[4] 42 U.S.C. § 7411(a)(1) (emphasis added).
[5] *Id* (emphasis added).
[6] *Lignite Energy Council v. United States EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (emphasis added).
[7] 88 FR 33246 (emphasis added).

> "Industrial combustion turbines have been burning byproduct fuels containing large percentages of hydrogen for decades, and recently, utility combustion turbines in the power sector have begun to co-fire hydrogen as a fuel to generate electricity… Furthermore, several utilities are co-firing hydrogen ***in test burns***; and ***some have announced plans*** to move to combusting 100 percent hydrogen in the 2035–2045 timeframe. Specifically, the Los Angeles Department of Water and Power's (LADWP) Scattergood Modernization project ***includes plans*** to have a hydrogen-ready combustion turbine in place when the 346-MW combined cycle plant (potential for up to 830 MW) begins initial operations in 2029. LADWP foresees the plant running on 100 percent electrolytic hydrogen by 2035. In addition, LADWP also has an agreement in place to purchase electricity from the Intermountain Power Agency project (IPA) in Utah. IPA is replacing an existing 1.8-GW coal- fired EGU with an 840-MW combined cycle turbine ***that developers expect*** to initially co-fire 30 percent electrolytic hydrogen in 2025 and 100 percent hydrogen by 2045. In Florida, NextEra Energy ***has announced plans*** to operate 16 GW of existing natural gas-fired combustion turbines with electrolytic hydrogen as part of the utility's Zero Carbon Blueprint to be carbon-free by 2045. Duke Energy Corporation, which operates 33 gas-fired plants across the Midwest, the Carolinas, and Florida, ***has outlined plans*** for full hydrogen capabilities throughout its future turbine fleet: "All natural gas units built after 2030 are assumed to be convertible to full hydrogen capability. After 2040, only peaking units that are fully hydrogen capable are assumed to be built."[8]

> "In both the [Infrastructure Investment and Jobs Act (IIJA)] and the IRA, Congress provided extensive support for the development of hydrogen produced through low-GHG methods. This support includes investment in infrastructure through the IIJA, and the provision of tax credits in the IRA to incentivize the manufacture of hydrogen through low GHG-emitting methods. These incentives ***are fueling interest*** in co-firing hydrogen and creating expectations that the availability of low-cost and low- GHG hydrogen will increase in the coming years. These projections are based on a combination of economies of scale as low-GHG production methods expand, the increasing availability of low-cost electricity—largely powered by renewable energy sources and potentially nuclear energy—and learning by doing as more turbine projects are developed."[9]

> "The clean hydrogen production tax credit ***is expected to*** incentivize the production of low-GHG hydrogen and ultimately exert downward pressure on costs. Low-cost and widely available low-GHG hydrogen ***has the potential to become*** a material decarbonization lever in the power sector as the use of low-GHG hydrogen in stationary combustion turbines reduces direct GHG emissions as hydrogen releases no CO_2 when combusted…"[10]

Tellingly, EPA cites *Portland Cement Ass'n v. Ruckelshaus* as justification for its projections. In that decision, the Court stated:

[8] *Id.* at 33254–33255 (emphasis added).
[9] *Id.* at 33255 (emphasis added).
[10] *Id.* at 33261 (emphasis added).

"The resultant standard is analogous to the one examined in *International Harvester*, supra. The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and ***cannot be based on crystal ball inquiry***. As there, the question of availability is partially dependent on lead time, the time in which the technology will have to be available. Since the standards here put into effect will control new plants immediately, ***as opposed to one or two years in the future***, the latitude of projection is correspondingly narrowed. If actual tests are not relied on, but instead a prediction is made, its validity as applied to this case ***rests on the reliability of [the] prediction and the nature of [the] assumptions***." [11]

With the Court's ruling firmly in hand, EPA must grapple with the critical fact that there is currently zero production of low-GHG hydrogen in the United States, nor are there any current manufacturing capabilities or infrastructure in place to produce low-GHG hydrogen. EPA piles assumption upon assumption to predict what might happen in the future, but at no point does EPA discuss existing hydrogen production, likely because no such fuel is currently available. A reasonable step from current to future technology might be allowable, but creation of a system of emission reduction from whole cloth is precisely the sort of "crystal ball" inquiry that the D.C. Circuit has ruled is impermissible. Imposing a new standard with unproven technology and availability presents a slew of risks for both regulator and regulated entity, and EPA has not demonstrated that low-GHG hydrogen as a viable option for the electric generating sector.

Even if EPA's predictions were reasonably adequate, the BSER is still problematic:

- EPA, relying upon a DOE estimate, predicts 10 million metric tons (MMT) of "clean hydrogen production" by 2030 and 20 MMT by 2040. However, the Agency concedes that these estimates are not based on production of low-GHG hydrogen but of "clean" hydrogen produced in accordance with DOE's specification.[12]

- EPA estimates that U. S. power sector hydrogen use will be 294 TBtu in 2030 and 347 TBtu in 2040[13], and Tennessee estimates that this would require 2.2 MMT and 2.8 MMT of hydrogen in 2030 and 2040, respectively (calculated from the HHV in **Table 1**). However, when total heat input is summed up for the 2022 source population, the result is a whopping 10,147 TBtu, 29

[11] 486 F.2d 375, 391 (D.C. Cir. 1973) (citation omitted) (internal quotations omitted) (emphasis added).
[12] DOE, as required by the IIJA, proposed a Clean Hydrogen Production Standard (CHPS) of having an overall emissions rate of 4 kg CO_2e/kg H_2. CHPS is not an actual standard, rather a non-binding tool for DOE's internal use with selecting projects under the H2Hubs program. *See* https://www.hydrogen.energy.gov/pdfs/clean-hydrogen- production-standard.pdf. How much low-GHG hydrogen, as defined by EPA, will be produced in 2030 and 2040? We have no idea, and apparently, neither does EPA.
[13] U. S. EPA, *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, May 2023, Table 3-10, https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0007/content.pdf.

times higher than EPA's 2040 estimate.[14] If we estimate future hydrogen needs from the current source population, 67 million tons of low-GHG hydrogen would be required to power the fleet of baseload EGUs in 2040 – twenty-four times as much as EPA's Btu-based estimate and over three times as much as DOE's mass-based estimate.

- When Tennessee calculated the amount of hydrogen that would be needed to comply with EPA's intermediate requirement (burn 30% low-GHG hydrogen by volume[15] in 2032), only 9.1 million metric tons of low-GHG hydrogen was required. This value is less than the 10 MMT/year of clean hydrogen production estimated for 2030, but it leaves EGUs with little margin for error. When we revised this estimate to consider intermediate load combustion turbines,[16] another 0.8 million tons per year of low-GHG hydrogen – an amount barely covered by DOE's production estimate – was required.

Table 1: Hydrogen and Methane Data		
Methane HHV	23,861 Btu/lb	*Perry's Chemical Engineers' Handbook*, 6th Edition, chapter 3, page 155
Hydrogen HHV	60,958 Btu/lb	
Density of hydrogen	0056 lb/ft^3 at 0° C and 1 atm	

[14] To determine the adequacy of EPA's projected hydrogen supply, Tennessee filtered EPA's CAMD database to select units: (1) that burn natural gas as the primary fuel; (2) are combined cycle as the unit type; (3) reported nonzero heat input in 2022; and (4) reported nonzero CO_2 emissions in 2022. Because we have no good way to determine which units would burn hydrogen rather than install carbon capture and storage, Tennessee also assumed a worst-case scenario in which all gas-fired baseload units elect to burn hydrogen. Note that this estimate did not consider how much additional hydrogen would be needed for intermediate-load simple cycle units. We used the data in Table 1 (using methane as a surrogate for natural gas), along with EPA's requirement for baseload gas-fired turbines to burn 96% hydrogen by volume in 2040, to calculate that about 88.5% of the heat input must come from hydrogen, with the remaining 11.5% from natural gas. One weakness of Tennessee's approach is that we did not attempt to account for future retirements and replacement of lost capacity with non-fossil generation (e. g., nuclear power or renewable energy). Fair enough, but (following the logic of the D.C. Circuit in *Portland Cement Ass'n*), we have no crystal ball with which to peer into the future. To the extent that EPA relies upon a wave of predicted retirements based on IPM modeling or other methods, the Agency fails the test set forth in *Portland Cement Ass'n*.

[15] Combustion of 30% hydrogen by volume corresponds to 12.05% of heat input from hydrogen.

[16] EPA proposes to create a low load subcategory to include combustion turbines that operate only during periods of peak electric demand, which would be separate from the intermediate load subcategory. Low-load combustion turbines, which would have no requirement to burn hydrogen, would be defined as combustion turbines that operate at capacity factors of 20% or less. Tennessee does not have the nameplate capacity of every turbine in the CAMD database, but if we look at CT plants using 1,000 hours per year as a surrogate for capacity factor, we have a source population of 612 units (out of a starting group of 1,105 CTs). This may overestimate the number of intermediate load units (which EPA estimates as about one-third of the source population), but the error in this case works in EPA's favor (our calculation of 2030 hydrogen requirements is less than 10 MMT/year, even if our source population of intermediate-load CTs is slightly overstated).

Table 1: Hydrogen and Methane Data		
Density of methane	0.0448 lb/ft^3 at 0° C and 1 atm	*Perry's Chemical Engineers' Handbook*, 6th Edition, chapter 3, page 78
Methane HHV	1,069 Btu/ft^3 at 0° C and 1 atm	Calculated values
Hydrogen HHV	341 Btu/ft^3 at 0° C and 1 atm	

BSER must be based on technology that has been adequately demonstrated or, following the guideline set forth by the D.C. Circuit, upon a reasonably-supported extrapolation of present technology. A reasonable, fact-based projection from current to future technology is allowable[17] – creation of a system of emission reduction from whole cloth is not. EPA's proposed BSER: (1) relies upon a nonexistent fuel supply; (2) bases its projections upon a fuel specification that does not meet EPA's own standard; and (3) is impossible to meet without massive changes to the existing source population.

Comment #2: EPA's Carbon Capture Option, As Proposed, Has Not Been Adequately Demonstrated.

For new combustion turbines, existing combustion turbines larger than 300 MW and operating at a capacity factor greater than 50%, and coal-fired boilers operating past December 31, 2039, EPA proposes to require carbon capture and storage (CCS) as a compliance option (gas-fired CTs can choose between CCS and combustion of low-GHG hydrogen, but CCS is the only compliance option for coal boilers). For gas-fired combustion turbines using the CCS Pathway, EPA proposes to require new and existing units to comply with a 90% capture requirement (90 lb CO_2/MWh-gross) beginning in 2035. For coal-fired units operating past December 31, 2039, EPA proposes to require CCS with 90%

---

[17] To support its position, EPA points to the installation of flue gas desulfurization (FGD) to comply with the sulfur dioxide emission limits of 40 CFR 60 Subpart D, at 88 FR 33367 as follows:

> FGD was rapidly deployed in the United States in response to various regulatory requirements, including the 1971 NSPS addressing SO2 emissions. Although other compliance options were available, FGD—a wholly new technology—was installed on 48 GW of coal-fired power plants between 1973 and 1984, while the number of technology vendors went from 1 to 16.

Tennessee agrees that the requirements of Subpart D resulted in improvements to control technology, but the standard itself was relatively modest (1.2 pounds of SO_2 per million Btu of heat input). Babcock and Wilcox (*Steam – Its Generation and Use*, 46th Ed (1992), Chapter 35, pp 1-2) reports that between 1970 and 1988, SO_2 emissions from electric utilities decreased from 15.8 million tons/year to 13.6 million tons/year. During that same period, the average sulfur content of coal decreased from 2.3% sulfur in 1970 to 1.09% sulfur in 1988. While there was a growth in scrubber use between 1970 and 1988 (by 1988, scrubbers accounted for 36% of all SO_2 reductions in the U. S.), the standard was achievable by fuel switching alone. A more robust driver of scrubber technology was Title IV of the 1990 Clean Air Act Amendments, in which ***Congress*** mandated sweeping reductions of SO_2 emissions.

capture of CO_2 an (88.4% reduction of uncontrolled CO_2 emissions). EPA asserts that CCS is adequately demonstrated, as follows: [18]

> Under CAA section 111(a)(1), an essential, although not sufficient, condition for a "system of emission reduction" to serve as the basis for an "achievable" emission limitation, is that the Administrator must determine that the system is "adequately demonstrated." This means, according to the D.C. Circuit, that the system is "***one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way***." It does not mean that the system "must be in actual routine use somewhere." Rather, the court has said, "[t]he Administrator may make a projection based on existing technology, though that projection is ***subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry."*** Similarly, the EPA may "hold the industry to a standard of improved design and operational advances, ***so long as there is substantial evidence that such improvements are feasible***." Ultimately, the analysis "is partially dependent on 'lead time,'" that is, "the time in which the technology will have to be available." The caselaw is clear that the EPA may treat a set of control measures as "adequately demonstrated" regardless of whether the measures are in widespread commercial use. For example, the D.C. Circuit upheld the EPA's determination that selective catalytic reduction (SCR) was adequately demonstrated to reduce NO_X emissions from coal-fired industrial boilers, even though it was a "new technology." The court explained that "section 111 'looks toward what may fairly be projected for the regulated future, rather than the state of the art at present.'" *Lignite Energy Council*, 198 F.3d at 934 (citing *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973)).[19] The Court added that the EPA may determine that control measures are

[18] 88 FR 33272–33273 (emphasis added).

[19] It is important to review the court's decision in *Lignite Energy Council* in context. The Clean Air Markets facility attributes database indicates that there were five coal-fired units using SCR controls at the time of the *Lignite Energy Council* decision in 1999. The number of SCR-controlled units grew to 11 units in 2000, 25 units in 2001, 51 units in 2002, 127 units in 2003, and 158 units in 2004. By 2005, the CAMD database indicates 171 units with SCR control. Given the rapid growth in SCR controls from 1999 to 2005 and beyond (much of which would have been known to EPA by 1999), it was reasonable for EPA to require SCR controls based on a projection of the near-term future.

By contrast, consider the lack of growth in CO_2 control technologies following the adoption of 40 CFR 60 Subpart TTTT in 2015. In 2022, four units (Deerhaven Unit B2 in Florida, Belews Creek Units 1 and 2 in North Carolina, and Cliffside Unit 6 in North Carolina) met EPA's CO_2 standard for new units (1,400 lb CO_2/MWh gross output), and none of these units use carbon capture and storage as a control technology. Both units at Belews Creek may co-fire up to 50% natural gas (see https://www.duke-energy.com/our-company/about-us/power-plants/belews-creek-steam-station), and the Deerhaven and Cliffside units co-fire up to 100% natural gas (see https://www.duke-energy.com/our-company/about-us/power-plants/rogers-energy-complex and https://www.wuft.org/news/2020/06/15/grus-switch-from-coal-to-cleaner-natural-gas-at-deerhaven-unit-2-would-cost-upwards-of-12m/). One unit (the Petra Nova carbon capture project at W. A Parish

> "adequately demonstrated" through a "reasonable extrapolation of [the control measures'] performance in other industries."

To support its contention that carbon capture is feasible, EPA offers two examples of working carbon capture systems at electric utilities (SaskPower's Boundary Dam Unit 3 and Unit 8 of the W. A. Parish Generating Station in Thompsons, Texas) and a third project at an oil refinery (Shell Canada's Quest Carbon)[20]. None of the examples offered by EPA would satisfy the carbon capture requirements proposed in this rulemaking due to poor reliability and low nominal control efficiency, as further described in this section. Furthermore, EPA overlooks the failure of a fourth carbon capture system, a state-of-the art demonstration project at an EGU in Mississippi. Finally, we note that natural gas turbines are likely to face unique operating challenges with respect to carbon capture, but EPA can point to no examples of working carbon capture systems at natural gas plants.

Only a single CCS system is currently in use at an EGU—SaskPower's Boundary Dam Unit 3 operation in Canada. EPA cites Boundary Dam #3 as one example of a working CCS system and asserts that this system "has demonstrated capture rates of 90 percent of the CO_2 in flue gas using solvent-based post-combustion capture retrofitted to existing coal-fired steam generating units."[21] The Agency proposes that "the CO_2 capture component of CCS is adequately demonstrated on the basis of Boundary Dam Unit 3 alone",[22] and this might be correct—if EPA could point to a history of reliable operation and compliance with the proposed standard, which it cannot.

EGUs in Canada are not subject to the Acid Rain Program, and (as far as Tennessee is aware) there is no readily available database equivalent to EPA's Clean Air Markets Program Data (CAMD) website. However, SaskPower places a fair amount of operating data on the facility's website, and these data give us a reasonable way to assess the facility's operation from the second quarter of 2022 to the first

---

Unit 8 in Texas) did operate CCS between 2017 and 2019, but this unit met EPA's Subpart TTTT standard for less than 50% of the unit's operating time during this period (10,916 hours out of 23,802 total operating hours). The Petra Nova CCS project ceased operation in 2019, and there are currently no U. S. EGUs operating carbon capture and storage on any unit. These facts must be considered when evaluating EPA's future-year projection for carbon capture and storage.

[20] During the final edits to these comments, Tennessee identified two additional plants (Warrior Run in Maryland and Shady Point in Oklahoma) that were not included in our initial analysis. For Warrior Run, EPA's CAMD database indicates that CO_2 emission rates from 2008 to 2022 (no CO_2 emissions were reported between 2000 to 2008) averaged 2,420 lb/MWh and ranged from 2,257 lb/MWh in 2008 to 2,574 lb/MWh in 2020 (for comparison, the average CO_2 emission rate from Tennessee's coal plants was 2,190 lb/MWh in 2022). By EPA's own admission, Warrior Run captured no more than 10% of the plant's CO_2 emissions (*see* 88 FR 33292). River Valley Power Station (formerly Shady Point) is more difficult to assess, because the CAMD database indicates only four years of operation (2019 through 2022) for each of the facility's four units, and these units appear to be operating at a reduced rate (total CO_2 emissions from each unit range from 133,000 tons to 450,000 tons). Furthermore, CAMD reports no electrical output from this facility, so we cannot calculate the units' CO_2 emissions on an output basis. However, the proposed rule states that this facility captured only 5% of the plant's CO_2 emissions (*see* 88 FR 33292) between 2001 and 2019. When these facilities are considered along with the others identified in the body of Tennessee's comments, our conclusions do not change.

[21] 88 FR 33346.

[22] *Id.*

quarter of 2023 (**Table 2**, see **Attachment 2** for supporting data). During this period, the operational availability of the carbon capture system was fairly high (above SaskPower's target availability of 75%), but the estimated control efficiency never exceeded 65%.

Table 2: Boundary Dam #3 Operating Data, 2022 Q2 through 2023 Q1				
	CCS Facility Availability	**CO_2 Emission Rate (Metric Tons/GWh)**	**CO_2 Emission Rate (lb/MWh)**	**Estimated Control Efficiency**[23]
2023 Q1	93.0%	354	780.4	65%
2022 Q4	78.9%	383.2	844.8	62%
2022 Q3	94.5%	436	961.2	56%
2022 Q2	96.0%	382	842.2	62%

Data for the second, third, and fourth quarters of 2022 (**Table 3**) indicates that the carbon capture system appears to have suffered from extended outages for three consecutive quarters, and the estimated control efficiency was poor.[24]

Table 3: Boundary Dam #3 Operating Data, 2021 Q2 through 2022 Q1				
	CCS Facility Availability	**CO_2 Emission Rate (Metric Tons/GWh)**	**CO_2 Emission Rate (lb/MWh)**	**Estimated Control Efficiency**
2022 Q1	50.0%	750	1,653.5	25%
2021 Q4	30.0%	850	1,873.9	15%
2021 Q3	10.0%	1,100	2,425.1	Approx. 0%
2021 Q2	70.0%	400	881.8	60%

During the eight quarters for which data are available Tennessee notes that Boundary Dam #3 was unable to meet EPA's proposed 90% capture efficiency ***even once***. Thus, even if CO_2 capture is acceptable in theory as BSER, Boundary Dam #3 does not support EPA's proposed numeric limits. Indeed, Boundary Dam #3 suggests that EPA's proposed control efficiency is unachievable over the long term with current technology.

EPA cites the Petra Nova carbon capture project as a second example of "CO_2 capture projects . . . [that] further corroborate the adequate demonstration" of a working carbon capture system.[25] This project operated at Unit 8 of the W. A. Parish Generating Station in Thompsons, Texas, and operated from 2017 to 2020 (**Table 4**). Data from W. A. Parish #8 are available on EPA's CAMD, and Petra Nova's annual emissions data indicate an output-based capture efficiency (calendar year basis) of 21% in

[23] Control efficiencies were estimated from a nominal value of 2,200 lb/MWh for uncontrolled CO_2 emissions.
[24] These data are a mixture of graphical and quantitative information, and Tennessee estimated the availability of the carbon capture system from the graphs.
[25] 88 FR 33347.

2017, 23% in 2018, and 33% in 2019.[26] The average capture efficiencies for 2017 and 2018 were below the target of 33% of CO_2 emissions from Unit 8,[27] and though the facility generally performed better than Boundary Dam #3, the fact remains that Petra Nova did not meet its target capture efficiency for two of the three years in which the facility operated. If one considers the 12-month rolling total control efficiencies (**Figure 1**), Unit 8 achieved its 33% target in exactly one month of the 24-month period for which data were available. The hourly data (**Figure 2**) indicate that operation of the system was highly variable, with periods of low and high emissions.[28] Petra Nova, like Boundary Dam Unit 3, does not support EPA's BSER determination, because the facility's operating data suggest that this system is unable to comply with EPA's proposed limits.

Table 4: W. A. Parish Generating Station, Unit 8 Emissions Data

Year	Heat Input (MMBtu)	Gross Load (MWh)	CO_2 Emissions (tons)	CO_2 Emission Rate (lb/MMBtu)	CO_2 Emission Rate (lb/MWh)
2010	39,699,437	4,313,202	4,156,583	209.4	1,927
2011	46,890,056	4,730,767	4,915,857	209.7	2,078
2012	32,368,055	3,301,667	3,390,299	209.5	2,054
2013	39,248,628	4,042,226	4,114,298	209.7	2,036
2014	44,113,956	4,481,612	4,625,523	209.7	2,064
2015	37,885,996	4,046,576	3,971,103	209.6	1,963
2016	38,126,758	3,792,115	4,011,512	210.4	2,116
2017	44,242,186	4,297,991	3,459,991	156.4	1,610
2018	39,668,473	3,788,225	2,978,149	150.2	1,572
2019	41,868,286	4,239,834	2,883,537	137.7	1,360
2020	26,600,107	2,583,904	2,430,995	182.8	1,882
2021	29,681,742	3,133,546	3,110,910	209.6	1,986
2022	13,360,446	1,377,715	1,400,145	209.6	2,033

[26] Tennessee estimated the output-based capture efficiency of Unit 8 from the unit's 2010-2016 average uncontrolled CO_2 emission rate of 2,033.9 lb/MWh.

[27] *See* EIA, TODAY IN ENERGY, PETRA NOVA IS ONE OF TWO CARBON CAPTURE AND SEQUESTRATION POWER PLANTS IN THE WORLD (2017), https://www.eia.gov/todayinenergy/detail.php?id=33552 ("The 240-megawatt (MW) carbon capture system that was added to Unit 8 (654 MW capacity) of the existing W.A. Parish pulverized coal-fired generating plant receives about 37% of Unit 8's emissions, which are diverted through a flue gas slipstream. Petra Nova's carbon-capture system is designed to capture about 90% of the carbon dioxide (CO2) emitted from the flue gas slipstream, or about 33% of the total emissions from Unit 8. The post-combustion process is energy intensive and requires a dedicated natural gas unit to accommodate the energy requirements of the carbon-capture process.").

[28] Some of this can be due to factors other than poor capture efficiency. For example, the boiler may be operating in startup mode with non-negligible heat input but negligible electrical output.

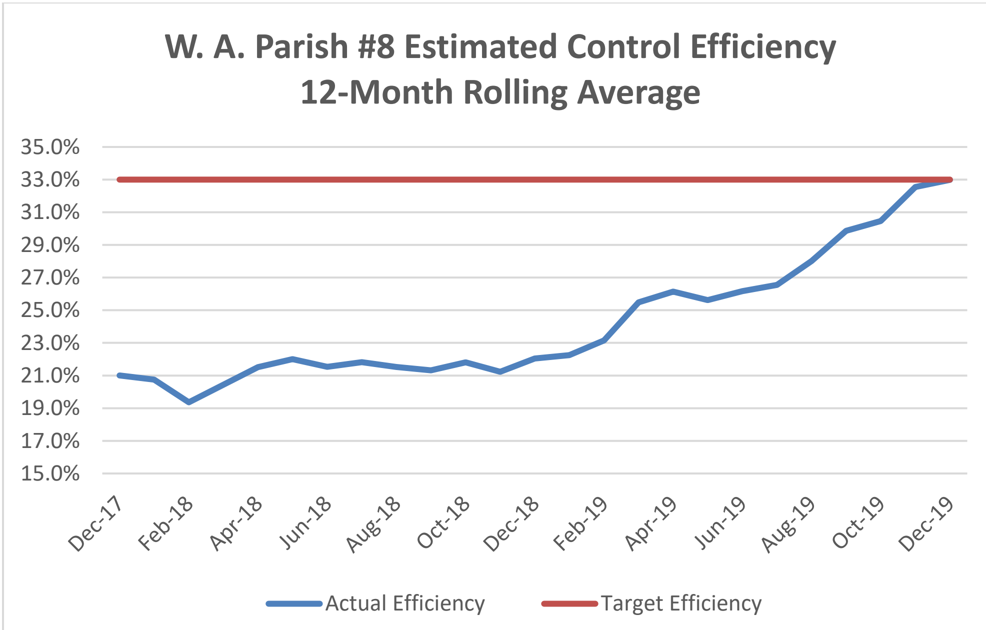


Figure 1: Petra Nova 12-Month Moving Total Control Efficiency

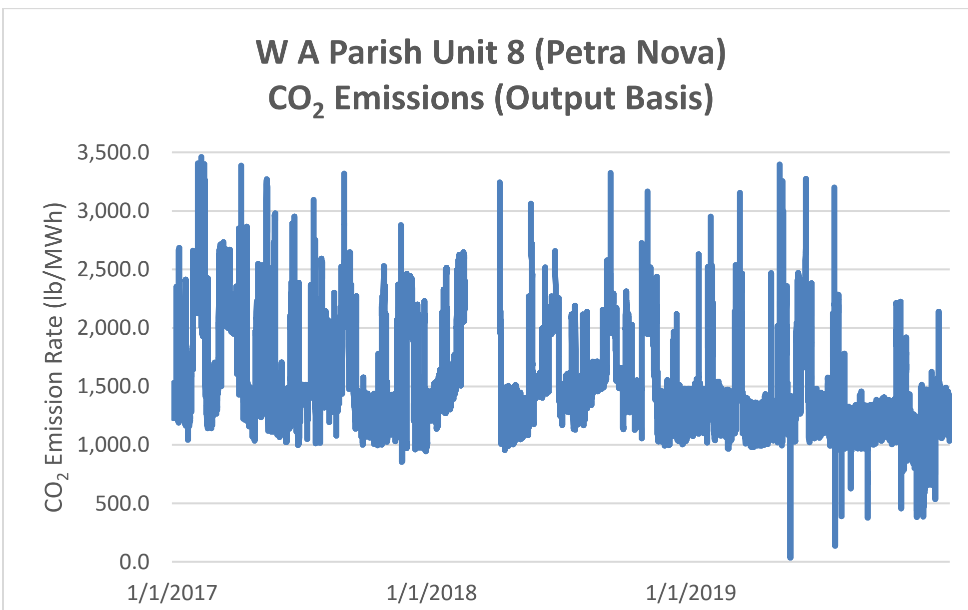


Figure 2: Petra Nova Hourly Emission Rate

A non-EGU example of carbon capture is Shell Canada's Quest Carbon Capture and Storage project.[29] This operation is a steam reforming plant that produces hydrogen from natural gas, and which, we believe, generates a stream of nearly pure CO_2. The Quest CCS project operates on a smaller scale and under near-ideal conditions, but this plant is also unable to achieve 90% capture efficiency required by the proposed rule (**Figure 3**).

[29] *See* QUEST CARBON CAPTURE AND STORAGE. SHELL, https://www.shell.ca/en_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html (last visited Aug. 3, 2023).

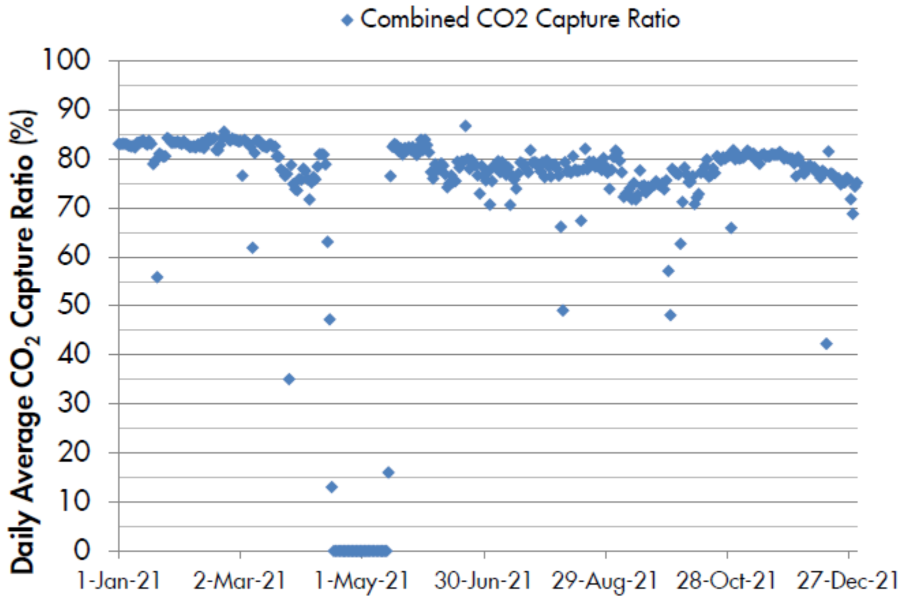


Figure 3: 2021 CO_2 Capture Efficiency at Shell Canada Quest CCS Project[30]

Tennessee highlights that the examples provided by EPA for currently implemented CCS technology fail to adequately demonstrate that this technology could be utilized at the sector-scale to achieve the limits required under this rulemaking.

Tennessee also notes that EPA's analysis ignores the failure of the Kemper CCS EGU project in Mississippi. This project was designed to capture approximately 65% of the plant's CO_2 emissions using a pre-combustion system (i. e., gasification of lignite and reaction of the syngas with water to produce a relatively pure stream of CO_2).[31] The Energy Information Administration reports that the capital cost of the Kemper project was initially estimated at $2.4 billion (about $4,100/kW, which is comparable to Petra Nova [$4,200/kW]), but cost overruns led to construction costs in excess of $7.5 billion (nearly $13,000/kW). Despite an enormous capital investment, the Kemper Project was abandoned prior to completion, and the carbon capture system was never successfully operated.

Tennessee acknowledges that the Kemper project was different from both Boundary Dam and Petra Nova based on technology differences (IGCC at Kemper, compared to pulverized coal at Boundary Dam and Petra Nova), and Kemper's construction delays and cost overruns may be explainable by site-specific factors. Nonetheless, EPA should account for all relevant projects that fall under its BSER determination, including the Kemper project. Finally, we note that even if the Kemper project had been completed on time and under budget, the plant was still designed to capture only 65% of the facility's CO_2 emissions, far below the rate required by EPA's proposed BSER.

---

30 See GOV'T OF ALBERTA, 2021 QUEST ANNUAL PERFORMANCE REPORT, https://open.alberta.ca/dataset/113f470b-7230-408b-a4f6-8e1917f4e608/resource/15b3bbe4-b034-40df-a71a-44b3cccad273/download/quest-annual-status-report-2021-co2-capture-ratio-performance.pdf.

31 See https://www.eia.gov/todayinenergy/detail.php?id=33552 for a brief overview of the Kemper project and https://en.wikipedia.org/wiki/Carbon_capture_and_storage for a brief discussion of pre-combustion CCS.

Finally, Tennessee notes that there are no examples of working carbon capture for simple cycle or combined cycle natural gas plants. In some ways, natural gas-fired turbines are not substantially different from coal plants, and since both operations produce similar gas streams, it is possible that carbon capture is technically feasible (albeit not at a 90% level). However, EPA cannot simply assume that coal technology is transferrable to natural gas, because the Agency must also consider factors such as the emission rate (lb CO_2 per megawatt-hour of gross output), concentration (ppm CO_2 in the stack gas) and startup/shutdown frequency. There are operating gas plants using carbon capture, and Tennessee does not know the extent to which these factors affect the feasibility of carbon capture for natural gas turbines.

Comment #3: Carbon Transport and Sequestration, At Scale, Are Not Adequately Demonstrated.

Currently, transport and storage of CO_2 occurs on a limited scale, and under ideal conditions, transport and sequestration are difficult-but-doable challenges that solve known problems using known technology. However, the expansion of carbon transport and sequestration to a national, industry-wide scale is orders of magnitude more difficult – the difference between a flight to Europe and a flight to Mars. A flight to Europe requires some planning and a modest outlay of cash, but a flight to Mars requires a massive capital investment and the assumption of extraordinary risk. Because a small carbon transport and storage network demonstrates that a flight to Europe is possible, EPA uses the same technology to justify a flight to Mars. However, the infrastructure for carbon transport and sequestration does not exist at the required scale, the availability of sequestration sites is likely constrained by geography, and the industry-wide application of carbon sequestration is not supported by EPA's proposal.

Transport of liquified or supercritical CO_2 will require an unprecedented expansion of the CO_2 pipeline system over the next twenty years. The proposed rule states, "The Pipeline and Hazardous Materials Safety Administration (PHMSA) reported that 5,339 miles of CO_2 pipelines were in operation in 2021, a 13 percent increase in CO_2 pipeline miles since 2011."[32] EPA does not estimate how much additional pipeline will be required to create a functioning CO_2 transport network,[33] but the current CO_2 pipeline network is miniscule compared to the existing natural gas pipeline network in the continental United States (approximately 3 million miles).[34, 35] If we assume that the 13% increase between 2021 and 2022 is representative of the amount of pipeline that would be added in the future, then the United States would have about 54,000 miles of CO_2 pipeline by 2040 – far more than we have now, but far less than

[32] 88 FR 33294.

[33] The docket for this rulemaking is substantial, and Tennessee concedes the possibility that we have overlooked this information. The public comment period for this rule may comply with the minimum requirements of the CAA and the Administrative Procedure Act, but in practice, the Agency publishes a massive volume of information and provides far too little time for a comprehensive review of such materials.

[34] See EIA, NATURAL GAS EXPLAINED: NATURAL GAS PIPELINES, https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php.

[35] A fully operational CO_2 network is likely to be smaller than the existing natural gas pipeline network, because the natural gas pipeline network must account for all end-users of natural gas (*e.g.*, utility, industrial, and residential consumers and liquified natural gas terminals).

is likely to be required. EPA's CAMD indicates that there were approximately 1,153 facilities generating electricity in 2022, and if each facility requires (on average) 100 miles of pipeline transport to the nearest CO_2 storage site, then about 115,000 miles of CO_2 pipeline would need to be constructed by 2040 – slightly more than twice as much as would be constructed at the current rate.[36], [37] These estimates also assume that states, utilities, and pipeline owners can, in fact, achieve the required tenfold (or greater) expansion of the CO_2 pipeline network over the next two decades, but the on-the-ground reality of pipeline construction is likely to be far more challenging. As EPA states in the proposed rule:[38]

> "States are also directly involved in siting proposed CO_2 pipeline projects. CO_2 pipeline siting authorities, landowner rights, and eminent domain laws reside with the states and vary from state to state. Pipeline developers may secure rights-of-way for proposed projects through voluntary agreements with landowners; pipeline developers may also secure rights-of-way through eminent domain authority, which typically accompanies siting permits from state utility regulators with jurisdiction over CO_2 pipeline siting. "

Siting issues, landowner rights, impacts on disadvantaged communities, and eminent domain are already controversial issues with respect to pipelines,[39] but for natural gas pipelines, the impact of these issues is mitigated by FERC oversight and eminent domain authority. No such federal oversight exists for the siting of CO_2 pipelines, and various property and right-of-way issues are likely to slow

---

[36] Tennessee's analysis does not consider the number of facilities that might burn hydrogen because the number of facilities that would burn (currently nonexistent) low-GHG hydrogen by 2040 is unknown. How would this affect the size of the pipeline network? Tennessee has no way to answer this question, and EPA makes no attempt at an answer in the proposal.

[37] Tennessee's estimate does not consider that some simple cycle plants would avoid both CCS and hydrogen requirements by limiting their capacity factor. Neither EPA nor Tennessee know how many simple cycle plants will use this option, and therefore, EPA must explain how 115,000 miles of pipeline (or an alternate value that the Agency can justify) will be constructed in time for facilities to comply with the rule.

[38] 88 FR 33294.

[39] For example, *see* Chris Davis, *32-mile natural gas pipeline project in Dickson County sparks controversy*, NEWSCHANNEL5NASHVILLE (Jan. 16, 2023),https://www.newschannel5.com/news/32-mile-natural-gas-pipeline-project-in-dickson-county-sparks-controversy.

the pace of CO_2 pipeline construction.[40] What happens if the pipeline network is inadequate? EPA explains that: [41]

> CO_2 can also be liquified and transported via vessel (*e.g.*, ship), highway (*e.g.*, cargo tank, portable tank), ship, or rail (*e.g.*, tank cars) when pipelines are not available. Liquefied natural gas and liquefied petroleum gases are already routinely transported via ship at a large scale, and the properties of liquified CO_2 are not significantly different. In fact, the food and beverage as well as specialty gas industries already have experience transporting CO_2 by rail. Highway road tankers and rail transportation can provide for the transport of smaller quantities of CO_2 and can be used in tandem with other modes of transportation to move CO_2 captured from an EGU.

To consider EPA's suggestion, it is helpful to review the list of facilities in EPA's CAMD database. In 2022, the total CO_2 emissions from these facilities were approximately ***1.6 billion tons***, and the median emission rate was ***494,000 tons***. Tank car capacities are limited to about 263,000 lb (131.5 tons),[42] so transport of liquefied CO_2 emissions would require at least 3,758 railcars per year for a single facility emitting at the median rate (roughly one railcar leaving the facility every two hours and 20 minutes). EPA does not opine on how many facilities will require rail transport of liquified CO_2.

With respect to sequestration of CO_2, EPA asserts:[43]

> Geologic sequestration potential for CO_2 is widespread and available throughout the U.S. Nearly every state in the U.S. has or is in close proximity to formations with geologic sequestration potential, including areas offshore. These areas include deep saline formation, unmineable coal seams, and oil and gas reservoirs. Moreover, the amount of storage capacity can readily accommodate the amount of CO_2 for which sequestration could be required under this proposed rule.

---

[40] The Congressional Research Service, in PAUL W. PARFOMAK, CONG. RESEARCH SERV., IN11944, CARBON DIOXIDE PIPELINES: SAFETY ISSUES *(2022)*, https://crsreports.congress.gov/product/pdf/IN/IN11944, pointed out that CO_2 pipelines in the Upper Midwest have faced opposition from landowners and advocacy groups for a variety of reasons, and that pipeline developers "have faced resistance securing voluntary agreements with landowners for pipeline rights-of-way through their properties." CRS states that, "Without voluntary agreements, developers may still secure rights-of-way through eminent domain authority," but have faced regulatory and legislative hurdles to eminent domain action. Specifically, CRS links to a comment from the Plymouth County (Iowa) Board of Supervisors (available online at https://wcc.efs.iowa.gov/cs/idcplg?IdcService=GET_FILE&allowInterrupt=1&RevisionSelectionMethod=latest&dDocName=2080832&noSaveAs=1), which states that CO_2 pipelines, "are not public utilities and should not receive eminent domain status." CRS also links to a March 2022 news story (available online at https://iowacapitaldispatch.com/2022/03/16/bill-switcheroo-would-delay-eminent-domain-for-pipelines/) in which the Iowa House proposed a one-year moratorium on eminent domain for CO_2 pipelines.

[41] 88 FR 33294.

[42] PERRY'S CHEMICAL ENGINEERS' HANDBOOK 111 (6th ed. 1985).

[43] 88 FR 33297.

When all potential sequestration sites are considered, EPA uses an estimate from the Department of Energy to assert that there is sequestration potential for between 2,400 billion to 21,000 billion metric tons of CO_2. EPA also highlights an assessment from the U. S. Geological Survey, which estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential across the U.S.[44] However, sequestration potential is constrained by geography, and these billions of tons of sequestration potential accomplish nothing if EGUs within a specific state lack access to sequestration sites. Tennessee has some preliminary information on sites that may be used for carbon sequestration, but a full evaluation will require several years and substantial cost. To better understand the challenges associated with CCS in Tennessee, the Tennessee Department of Environment and Conservation's (TDEC) Division of Air Pollution Control coordinated with TDEC's Division of Mineral and Geologic Resources and the Tennessee Geological Survey (TGS) to summarize our existing knowledge regarding CCS availability within the state. The full report is included in **Attachment 3** to these comments, and the key points of this report are summarized below:

- Tennessee appears to be limited to **only one** of five potential types of geologic storage units for CCS (deep saline formations);

- Sequestration appears **confined to Middle Tennessee** based on the complex geology of East Tennessee and the geologic hazards of West Tennessee;

- The Southeast Regional Carbon Sequestration Partnership estimates that Tennessee has only **eight years of CCS storage capacity** based on 2010 emission rates; and

- From here, site-specific assessments will be required. These assessments require a **substantial investment of time and money.** Tennessee cannot complete these assessments within the two-year period allowed by EPA, especially without additional funding to support the effort. The total cost of these assessments is unknown.

While Tennessee EGUs may have access to carbon sequestration resources in neighboring states, Tennessee has limited ability to assess the viability of those sites, and for EGUs located in the eastern third of the state, nearby sites in Kentucky, Virginia, or North Carolina are likely to encounter many of the same geologic challenges identified in the TGS report (i. e., the Blue Ridge, Valley and Ridge, and Appalachian Plateau physiographic provinces that predominate in these regions have the same complex geology and will require site-specific assessments for CCS viability). Additionally, out of state transport will further the need for miles of pipeline to transport the CO_2 safely which, as described previously, presents its own set of challenges.

Finally, Tennessee observes that EPA's permit process for Class VI Underground Injection Control (UIC) wells appears to be moving at a slow pace. The proposed rule states that EPA is currently reviewing permit applications for proposed sequestration sites in at least seven states,[45] but permits have been

---

[44] U.S. Geological Survey, Geologic Carbon Dioxide Storage Resources Assessment Team, National Assessment of Geologic Carbon Dioxide Storage Resources–Summary: Factsheet 2013-3020 (2013), *https://pubs.usgs.gov/fs/2013/3020/*.

[45] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 12, 2023. *https://www.epa.gov/uic/class-vi-wells-permitted-epa* .

issued for only two of the 77 UIC Class VI permit applications (both Archer Daniels Midland sites in Illinois) on EPA's website.[46] One site in California withdrew its application, and the remaining applications are listed as pending, with all projects in the pre-construction phase. While it is feasible to transport compressed CO_2 through pipelines to geologic sequestration sites, EPA's analysis does not come close to considering the actual requirements for the electric utility sector as a whole (*i. e.*, assessing the feasibility of creating an entire infrastructure and industry where none currently exists).

Comment #4: EPA's Costs Appear Understated.

EPA notes that any requirement to install pollution controls entails additional costs, and in some cases, these requirements may trigger a lengthy process of implementing pollution controls. Section 111 requires EPA to consider costs but does not dictate *how* such costs must be considered.[47] Instead:[48]

> [T]he D.C. Circuit has formulated the cost standard in various ways. It has stated that the EPA may not adopt a standard the cost of which would be "exorbitant," "greater than the industry could bear and survive," "excessive," or "unreasonable."[49] These formulations appear to be synonymous, and for convenience, in these rulemakings, we are treating them as synonymous with reasonableness as well, so that a control technology may be considered the "best system of emission reduction … adequately demonstrated" if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable.

EPA notes that the D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance, including standards that entailed significant costs.

In reviewing EPA's cost data, Tennessee found that EPA's capital cost estimates do not align with known costs for similar projects. EPA estimates capital costs ranging from $1,915/kW to $2,557/kW[50] for coal-fired EGUs, but Tennessee has already noted that the capital cost of Petra Nova was substantially higher at $4,200/kW. EPA relies upon the Integrated Planning Model (IPM) to develop CCS retrofit costs,[51] but a more accurate representation of capital cost is the amount that has been paid for existing CCS systems – and these costs are substantially higher than EPA's projections. Similarly, EPA estimates a capital cost of $1,440/kW[52] for new natural gas combustion turbines, but EPA has elsewhere indicated higher costs for combined cycle CCS ($2,081/kW in 2030).[53]

---

[46] *See Id.*

[47] *See* 42 U.S.C. § 7411.

[48] 88 FR 33273.

[49] Citing *Lignite Energy Council*, 198 F.3d at 933; *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975); *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981)..

[50] *Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document*, Table 6.

[51] Documentation for the IPM is available online at https://www.epa.gov/power-sector-modeling/documentation-post-ira-2022-reference-case.

[52] *Greenhouse Gas Mitigation Measures – Carbon Capture and Storage for Combustion Turbines Technical Support Document*, Figure 7.

[53] *See* https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.

EPA may reasonably argue that its projected costs hinge in part on investments spurred through Inflation Reduction Act (IRA) and that costs will come down as the technology is implemented at scale. The cost of hydrogen fuel turbines and carbon capture systems may or may not decrease over time[54], but it is doubtful that the Agency has fully considered the costs and timing requirements of infrastructure for hydrogen fuel delivery or CO_2 transport. While Congress and the Biden Administration have provided monetary incentives for such infrastructure, nothing has been done to provide a legal and practical fast track for critical pipeline or transmission projects that would be necessary to comply with the requirements of the proposed rule.

Conclusion

The proposed rule identifies the U. S. power sector as both a key contributor to climate change and a key component of the solution to reduce greenhouse gas emissions, but any solutions must be undertaken in accordance with the provisions of the Clean Air Act. EPA correctly notes, "The central requirement is that the EPA must determine the 'best system of emission reduction . . . adequately demonstrated,' taking into account the cost of the reductions, non-air quality health and environmental impacts, and energy requirements,"[55] but the proposed rule fails the first, and most important, component of BSER. Neither the proposed requirement to use of hydrogen as fuel nor the requirement to install carbon capture and storage meets the requirement that BSER be adequately demonstrated, using the very legal standards that EPA applies in the proposed rule. The actions that the EPA proposes are inconsistent with the requirements of CAA Section 111 and its regulatory history and caselaw.

[54] For example, EPA frequently pushes the boundaries of existing technology when it adopts more stringent emission standards for mobile sources, and when the engineering design of new engine models is complete, the cost of those newer engines can reasonably be expected to decrease over time.
[55] CAA Section 111(a)(1).

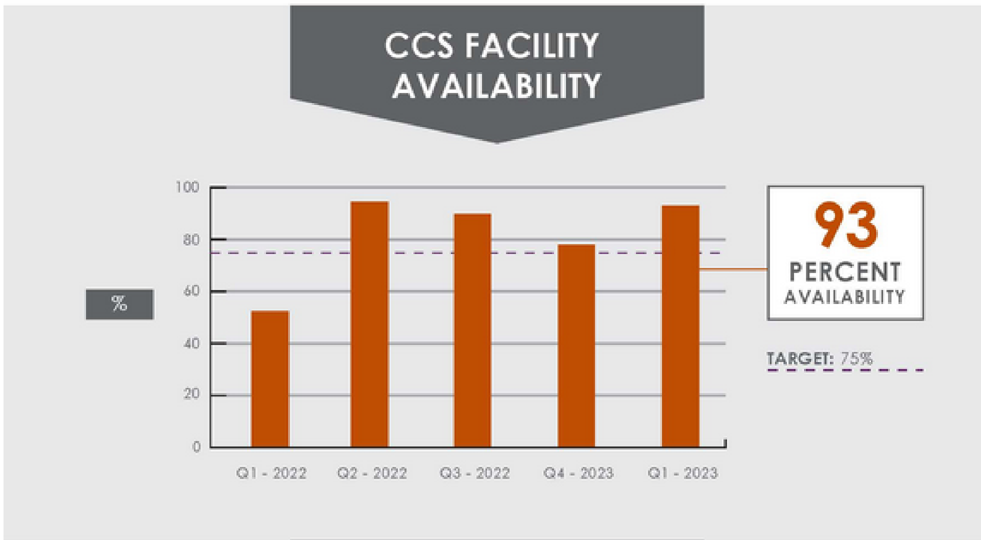
Attachment 1: Summary of Proposed Emission Standards

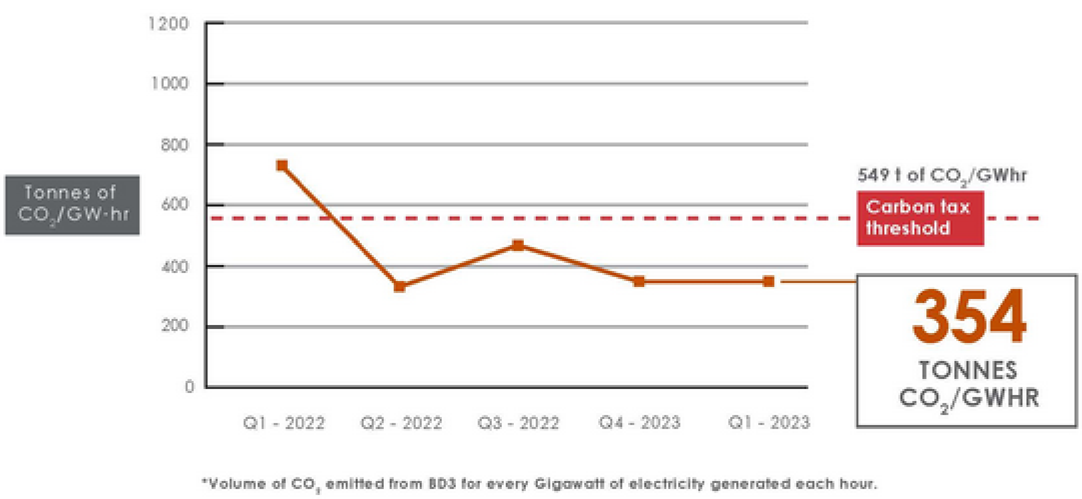
Table A1-1: Proposed New Source Performance Standards (CAA §111(b))			
Subcategory	**Phase I (startup date or final rule date)**	**Phase II (2032-2035)**	**Phase III (2038)**
Low load subcategory (capacity factor < 20%)	Use of natural gas and distillate oil, 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on fuel type	None.	
Intermediate load subcategory (capacity factor 20-50%)	Highly efficient simple cycle generation, 1,150 lb CO_2/MWh-gross	Continued highly efficient simple cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 (1,000 lb CO_2/MWh-gross)	None.
Baseload subcategory (capacity factor > 50%)	Highly efficient combined cycle generation, 770 lb CO_2/MWh-gross (EGUs with a baseload rating ≥ 2,000 MMBtu/hr) or 770-900 lb CO_2/MWh-gross (EGUs with a baseload rating < 2,000 MMBtu/hr)	**Low-GHG Hydrogen Pathway**: Continued highly efficient combined cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 (680 lb CO2/MWh-gross)	**Low-GHG Hydrogen Pathway:** Co-firing 96% (by volume) low-GHG hydrogen beginning in 2038 (90 lb CO2/MWh-gross)
		CCS Pathway: Continued highly efficient combined cycle generation with 90% CCS beginning in 2035 (90 lb CO_2/MWh-gross)	**CCS Pathway:** No Phase III BSER component or standard of performance

Table A1-2: Proposed Emission Guidelines for Existing Sources (CAA §111(d))	
Subcategory	**BSER/Emission Guideline**
Coal-Fired Boilers	For units operating past December 31, 2039, CCS with 90% capture of CO_2 (88.4% reduction)
	For units that cease operations before January 1, 2040 and are not in other subcategories, co-firing 40% (by volume) natural gas with emission limitation of a 16% reduction in emission rate (lb CO_2/MWh-gross basis)
	For units that cease operations before January 1, 2032, and units that cease operations after January 1, 2035, that adopt enforceable annual capacity factor limit of 20%, routine methods of operation and maintenance with associated degrees of emission limitation of no increase in emission rate
Natural Gas and Oil-Fired Boilers	Routine methods of operation and maintenance with of no increase in emission rate (lb CO_2/MWh-gross).
Natural Gas Combustion Turbines (>300MW and >50% capacity factor)	**CCS Pathway**: By 2035: highly efficient generation coupled with CCS with 90% capture of CO2 (90 lb CO_2/MWh). **Low-GHG Hydrogen Pathway**: By 2032: highly efficient generation coupled with co-firing 30% (by volume) low-GHG hydrogen (680 lb CO_2/MWh). By 2038: highly efficient generation coupled with co-firing 96% low-GHG hydrogen (90 lb CO_2/MWh).

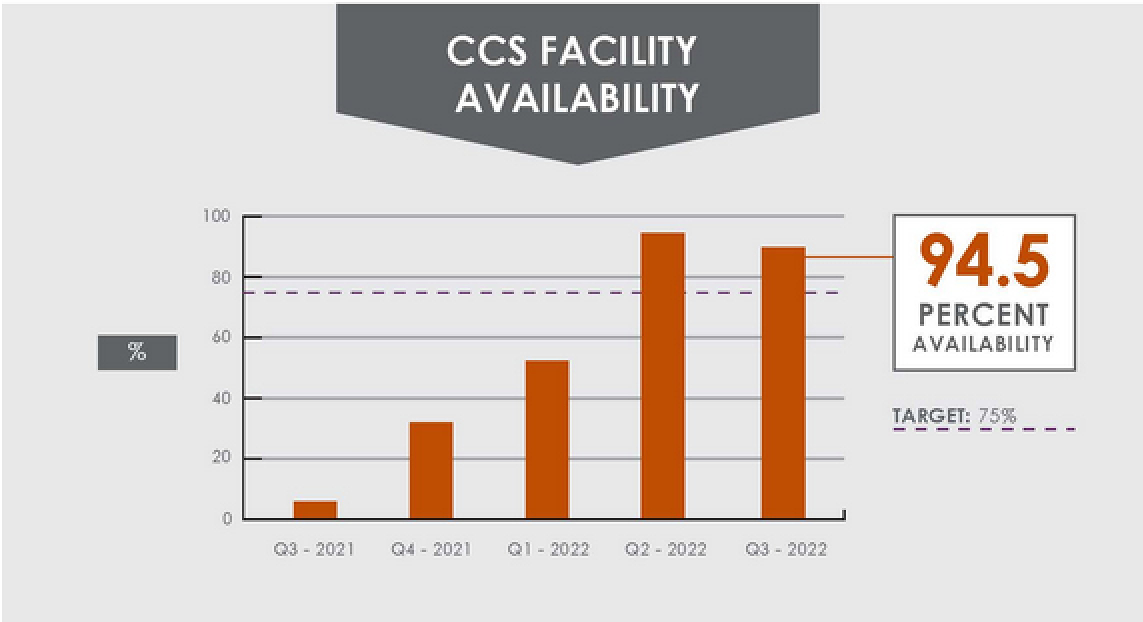
Attachment 2: Operating Data for SaskPower Boundary Dam #3

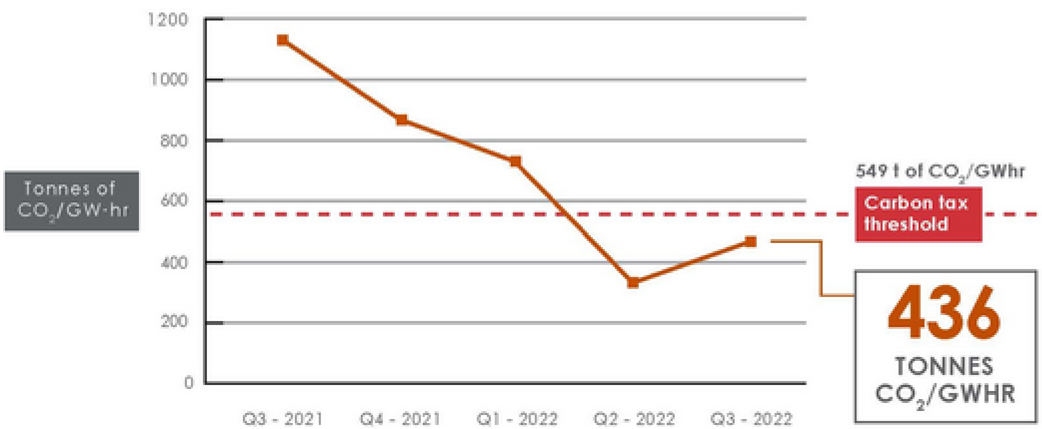
The following graphics are available online at https://www.saskpower.com/about-us/Our-Company/Blog.



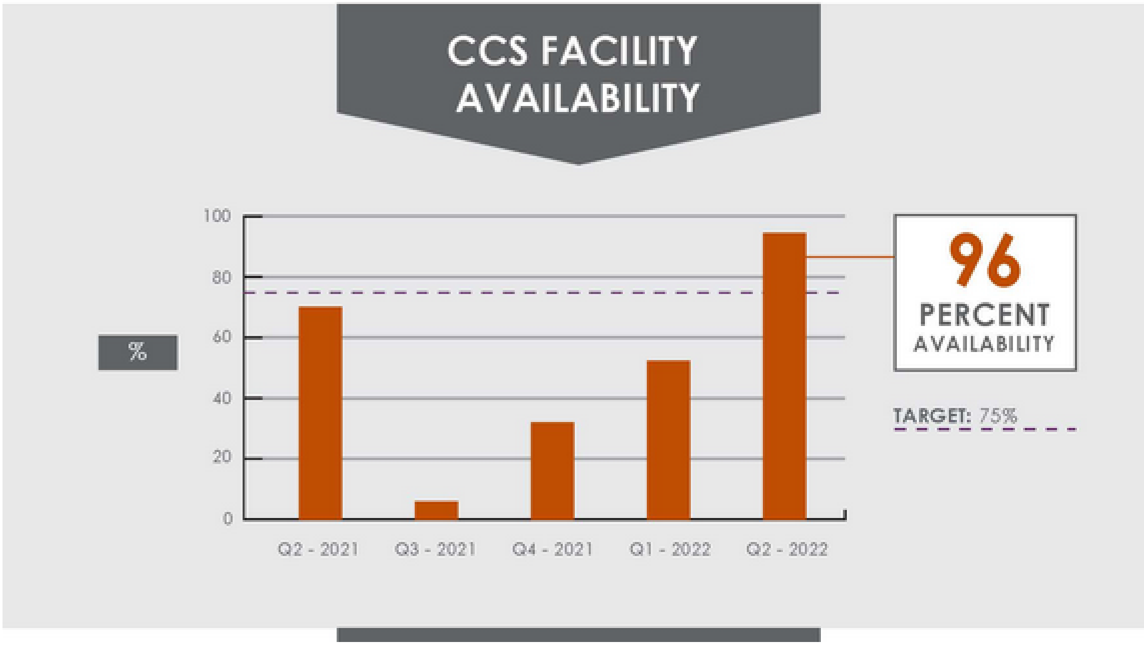


*Volume of CO_2 emitted from BD3 for every Gigawatt of electricity generated each hour.





*Volume of CO_2 emitted from BD3 for every Gigawatt of electricity generated each hour.



*Volume of CO2 emitted from BD3 for every Gigawatt of electricity generated each hour.

Attachment 3: Carbon Capture and Storage Assessment

Peter Lemiszki, Tennessee Geological Survey

"Congressional interest in addressing climate change has also increased interest in CCS, though debate continues as to what role, if any, CCS should play in greenhouse gas emissions reductions. While some policymakers and other stakeholders support CCS as one option for mitigating CO_2 emissions, others raise concerns that CCS may encourage continued fossil fuel use and that CO_2 could leak from underground reservoirs into the air or other reservoirs, thereby negating climate benefits of CCS[56].

The purpose here is to provide a summary of the current understanding for carbon capture and sequestration (CCS) in Tennessee and to comment on the level of effort needed to improve that understanding. The Department of Energy (DOE) National Energy Technology Laboratory (NETL) has conducted and/or supported a wide-range of Carbon Capture and Storage (CCS) investigations. The 5th edition of the NETL Carbon Storage Atlas (2015) includes the most recent synopsis of CCS potential in Tennessee[57,58]. There are five types of potential geologic storage units for CO_2 in the state:

1. deep saline formations,
2. depleted oil and gas reservoirs,
3. unmineable coal seams,
4. organic-rich shales, and
5. basalt formations.

Of the five scenarios listed above, the 5th edition of the NETL Carbon Storage Atlas (2015) indicates that deep saline formations offer the best potential for CCS in Tennessee. Carbon dioxide is best stored underground as a supercritical fluid, which means that it has some properties like a gas and some properties like a liquid. At temperatures exceeding 31.1°C and pressures exceeding of 1057 psi, CO_2 behaves as a supercritical fluid. The pressure-temperature phase diagram for carbon dioxide indicates that under hydrostatic conditions, reservoirs at depths greater than 2600 ft may provide the best storage conditions.
Besides the 2600 ft minimum depth constraint, deep saline reservoirs are only suitable for CO_2 storage if one or more overlying nonporous formations are present to serve as a vertical seal, preventing upward movement of the buoyant CO_2. Based on these two minimum requirements, there are two potential deep saline formations in Tennessee where CO_2 injection would likely occur under supercritical conditions. Their location, however, is somewhat limited in aerial extent across the state as shown in Figure 1.

The aerial extent of potential deep saline formations for CCS in Tennessee shown in Figure 1 appears to be based on the results from a 2011 NETL funded study of the deepest saline formation in the state, which is referred to as the "basal sandstone" (see Figure 2 below). The few deep wells that reach the basal sandstone are in Middle Tennessee, but the formation likely underlies all of western Tennessee. Although TGS contends that insufficient core and well-log data are available to make a quantitative assessment of the basal sandstones' storage potential, the conclusions from the 2011 study are provided in their Tables 5 and 6 below[59].

[56] Congressional Research Service. *Carbon Capture and Sequestration (CCS) in the United States,* October 5, 2022, page 1.
[57] U. S. Department of Energy. *2010 Carbon Sequestration Atlas of the United States and Canada, 3rd Edition*.
[58] U. S. Department of Energy. *2015 Carbon Sequestration Atlas of the United States and Canada, 5th Edition.*
[59] *CO_2 Sequestration Assessment of the basal sandstone in Tennessee*. SECARB Phase III Work Product 1.6.a

The lack of enthusiasm for considering CCS in west Tennessee is due in part because it is adjacent to the seismically active New Madrid Seismic Zone. In other areas of the country the subsurface injection of fluids has been known to alter the local stress field causing existing faults to slip or to create new faults. Earthquake magnitudes have on occasion reached levels that cause significant ground shaking. In addition, there is also the possibility that a storage site may be compromised because of ground shaking and deformation.

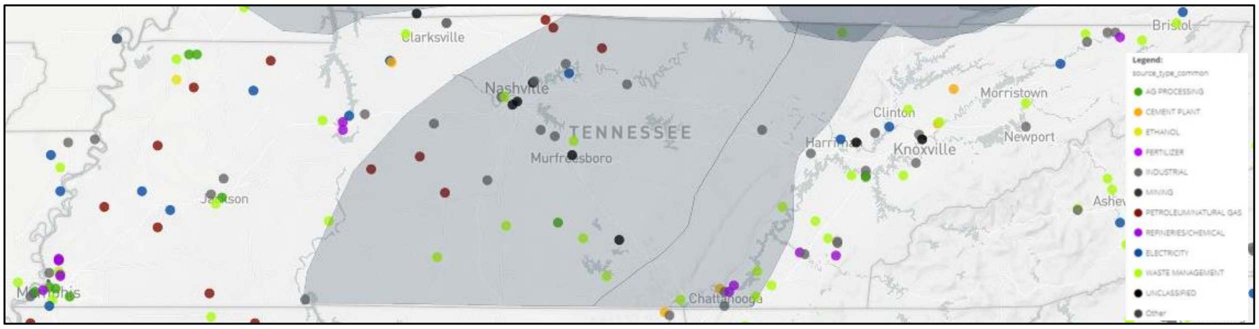


Figure 1. Results for Tennessee from the National Carbon Sequestration Database (NATCARB). Gray Shaded Area = Aerial extent of potential Saline Formation Storage. Colored Dots = Stationary carbon dioxide sources (2023; from https://edx.netl.doe.gov/geocube/#natcarbviewer)

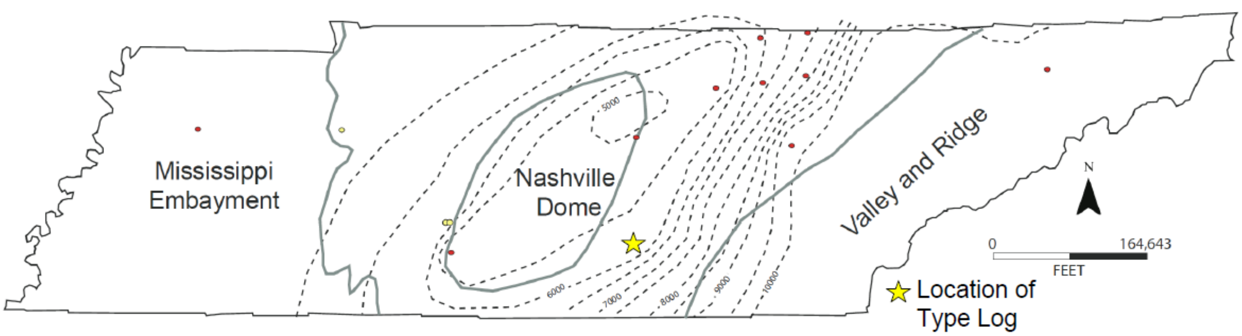


Figure 2. Depth in feet to the top of the 'Basal' sandstone in middle Tennessee. All circles represent wells used in this assessment. The yellow circles represent wells used for waste injection. Contours are in feet (Advanced Resources International, Inc, 2011).

Table 5. Reservoir Characteristics of the Basal Sandstone

Basal Sandstone	*Total Area (Mi2)*	*Avg Depth (ft)*	*Avg Gross Thickness (ft)*	*Avg Total Porosity (%)*	*Pore Volume (tcf)*	*Bg $_{CO2}$ (res cf/scf)*	CO_2 Capacity (Tscf) (E=100%)
Zone 1	14200	5978	112	7	3	0.00334	975
Zone2	4150	8314	128	8	1	0.00312	356

Table 6. CO2 Storage Capacity Results

	CO_2 Storage Capacity			
	Trillion Standard Cubic Feet (Tscf)		Billion Metric Tons (Gt)	
Basal Sandstone	High Estimate P(90%)	Low Estimate P(10%)	High Estimate P(90%)	Low Estimate P(10%)
Zone 1	56.03	5.93	2.96	0.31
Zone2	18.16	1.92	0.96	0.10

The Tennessee Geological Survey (TGS) completed a study for the U.S. Geological Survey's nationwide CCS assessment circa 2010-2013. Figure 3 is one of three east-west geologic cross sections that start near the eastern margin of the gray-shaded area in Figure 1 and ends at the Mississippi River in west Tennessee. The cross section is based on all the available subsurface information and shows that there are two potential deep saline formations: the green colored Stones River and Knox Groups (SRKG), which was the focus of the TGS study, and the yellow-colored Cambrian Basal Sandstone. Based on the available information, it can be stated for certain that the SRKG only lies below a depth of 3000 feet in the eastern side of the cross section beneath the Cumberland Plateau in Campbell County. The SRKG may also reach depths below 3000 feet in far western Tennessee. Although substantially thicker than the Basal Sandstone, there is insufficient core and well-log data available to make a quantitative assessment of the SRKG storage capacity. As mentioned above, the deeper Basal Sandstone (also called the Mount Simon Sandstone in some publications) may occur at suitable depths for CCS across the entire region, but this has not been confirmed.

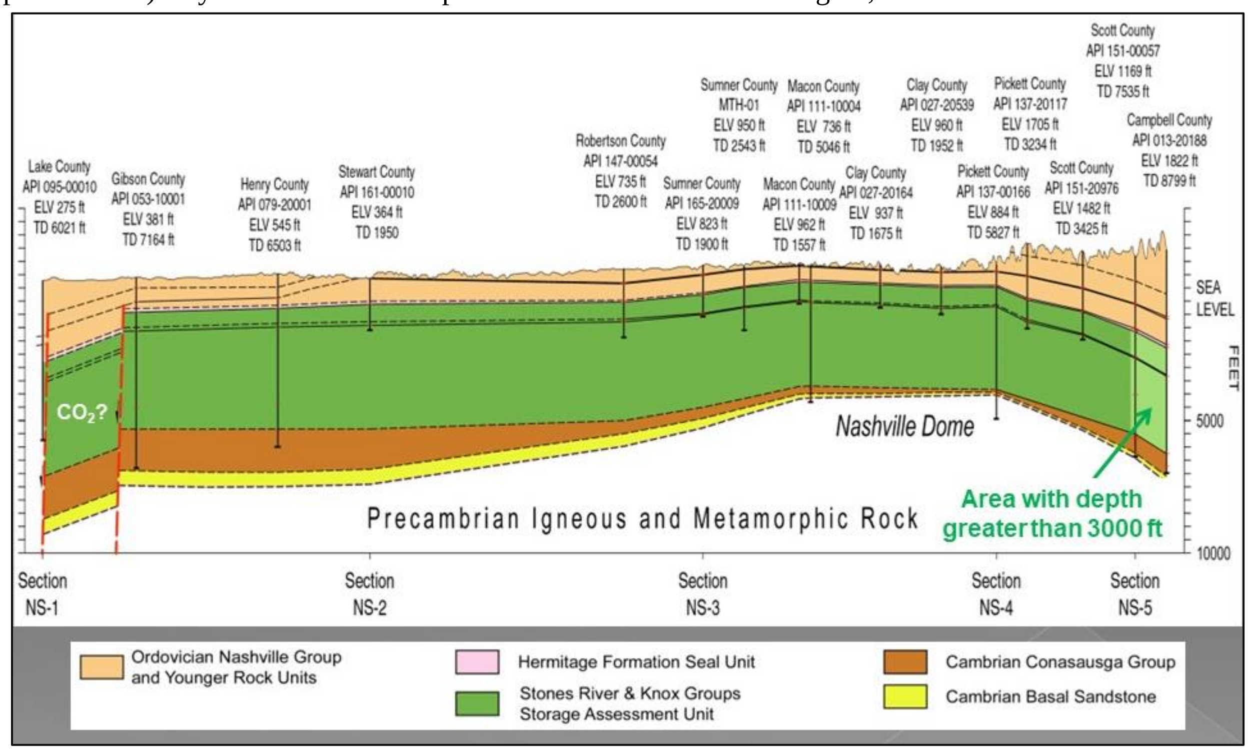


Figure 3. East west geologic cross section from Campbell County to Lake County, Tennessee. The term "Basal Sandstone" refers to sandstones of different ages and composition that were deposited on top of the Precambrian unconformity.

The bedrock in East Tennessee's Valley and Ridge and Blue Ridge Provinces (from the east side of the gray area in Figure 1 to the North Carolina border) consists of faulted and folded sedimentary rock strata (Figure 4). Drill hole data for these provinces are sparse. Interpretations of the subsurface geology are based on surface geologic mapping and two-dimensional seismic reflections profiles. Although there may be suitable deep saline formation CCS targets, the best approach in this more complex geologic setting would be to complete site-specific investigations as needed.

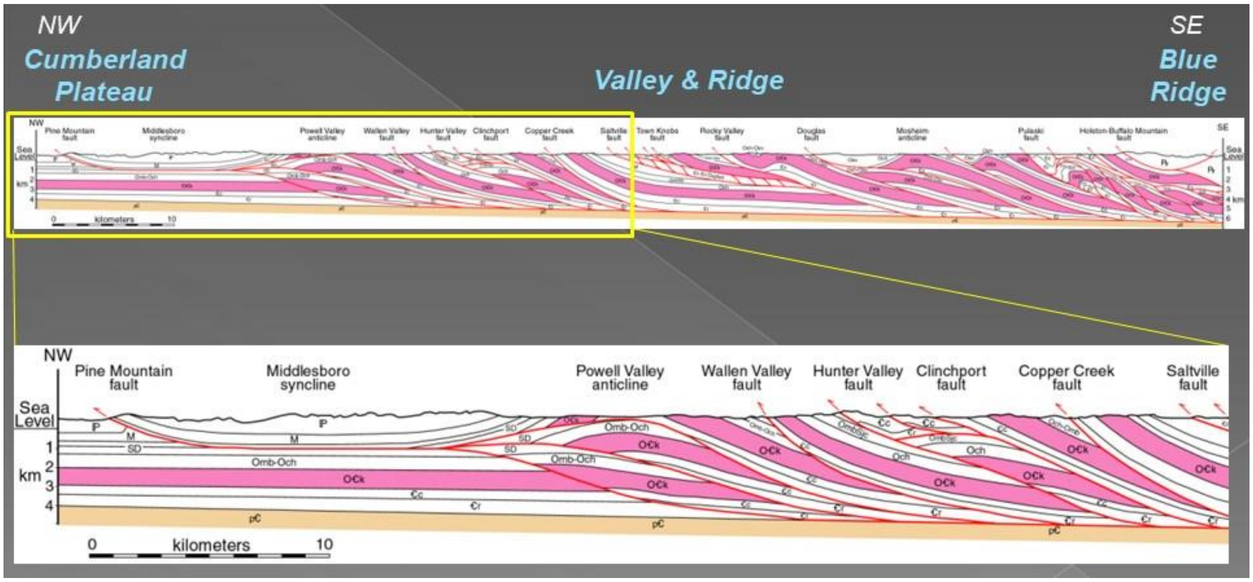


Figure 4. Geologic cross section across the Valley and Ridge Province, southern Appalachian foreland fold-thrust belt (Woodward, 1986). The Knox Group potential CO_2 storage unit is colored pink.

The 2010 and 2015 Carbon Storage Atlas' provide an initial assessment of the CO_2 stationary source emissions and CO_2 storage resource estimates for each state. The data for Tennessee is shown in the tables below, copied directly from each Atlas. By necessity, the capacity calculations are high-level estimates, and consequently, actual capacity remains unproved and even speculative. It is important to understand that no deep rock unit is completely homogenous or open to injection of fluids and gases. Factors such as reservoir heterogeneity, CO_2 buoyancy, and rock and water chemistry are likely to reduce the theoretical capacity to an "effective capacity." In addition, other factors such as infrastructure, engineering, and economic and regulatory policy will affect the viability of geologic carbon storage in the state.

<u>Tables from the DOE NETL 2010 Carbon Storage Atlas</u>

CO_2 Stationary Sources of the SECARB Region (million metric tons of CO_2 per year)

CO_2 Stationary Sources of the SECARB Region (million metric tons of CO_2 per year)

State	Electric Generation*	Fertilizer*	Cement Plants*	Ethanol*	Industrial*	Petroleum/ Natural Gas*	Refineries/ Chemical*	Total*
TN	61.8	0.0	1.5	0.4	0.2	0.0	1.8	66

CO_2 Storage Resource Estimates for Oil and Gas Reservoirs

CO_2 Storage Resource Estimates for Oil and Gas Reservoirs									
State	Number of Fields		Cumulative Conventional Recovery		Conventional CO_2 Storage Resource		Technically Recoverable Oil from CO_2-EOR	Additional CO_2 Storage Resource*	
	Total	Assessed	Oil Million Bbls	Gas Bcf	Million Metric Tons	Bcf	Million Bbls	Million Metric Tons	Bcf
TN	213	213	-	-	-	-	-	-	-

CO_2 Storage Resource Estimates for Saline Formations

CO_2 Storage Resource Estimate for Saline Formations					
Saline Formations	State	CO_2 Storage Resource			
		Trillion Cubic Feet		Billion Metric Tons	
		Low Estimate	High Estimate	Low Estimate	High Estimate
Mt. Simon Sandstone	TN	9	130	0.5	7

Estimated Years of Storage

Estimated Years of Storage						
State	CO_2 Sources (Million Metric Tons)	CO_2 Storage Resource (Million Metric Tons)				Number of Years Storage ***
	Total	Oil and Gas	Coal and Shale*	Saline*	Total	
AL	80	344	1,944	12,900	15,188	190
AR	35	250	15,675	4,304	20,229	572
FL	143	109	1,275	16,725	18,109	127
GA	90	-	-	4,909	4,909	55
LA	102	6,781	8,325	139,497	154,603	1,520
MS	34	399	5,400	46,427	52,226	1,546
NC	77	-	-	1,352	1,352	18
SC	40	-	-	1,995	1,995	49
TN	66	-	-	500	500	8
TX**	373	4,005	33,025	205,548	242,578	650
VA	46	10	231	159	400	9
Federal Offshore	N/A	17,754	-	484,996	502,750	N/A
Total	**1,085**	**29,652**	**65,875**	**919,313**	**1,014,840**	**935********

Information for other states in the Southeast Regional Carbon Sequestration Partnership are included for comparison.

Table from the DOE NETL 2015 Carbon Storage Atlas*

State/ Province	CO_2 Emissions		Oil and Natural Gas Reservoirs Storage Resource			Unmineable Coal Storage Resource			Saline Formation Storage Resource			Total Storage Resource		
	Million Metric Tons Per Year	Number of Sources	Billion Metric Tons			Billion Metric Tons			Billion Metric Tons			Billion Metric Tons		
			Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate
Tennessee	50	90	0.00	0.00	0.00	0.00	0.00	0.00	0.50	1.85	4.63	0.50	1.85	4.63

**Note that according to the U.S. Energy Information Administration (EIA) Tennessee produced 83.3 million metric tons of energy-related carbon dioxide in 2020.*

Since the 2015 publication of the NETL Carbon Storage Atlas, a 2017 study conducted a site-specific CO_2 injection test to evaluate the potential for enhanced gas recovery and storage of CO_2[60]. The primary goal of this project was to inject 500 tons of CO_2 to assess the injection and storage potential of CO_2 in an organic shale formation while monitoring for enhanced gas recovery. The Chattanooga Shale formation, located in Morgan County, Tennessee, was selected for this project in order to make use of a producing deep natural gas well. Although it is not clear at this time, which well was chosen, the depth to the top of the Chattanooga Shale for the six horizontal-well injection candidates located in Anderson and Morgan counties ranged from approximately 2550 to 3675 feet. The depths of these candidate wells were adequate for conducting a small-scale CO_2 injection test. The injection of CO_2 into the shales should displace naturally occurring CH_4 in the shale matrix and along fractures in the shale, so that enhanced gas recovery is possible. One advantage of this approach is that it would allow a revenue stream to be developed to help offset the costs of carbon storage. The study concluded that:

1. Based on the significant flow rates and relatively low injection pressures, the injectivity of CO_2 into fractured organic shale reservoirs was confirmed.
2. Once the well was brought back online after the soaking period, a significant increase in gas production occurred.
3. The results from the monitoring program confirmed that there was no communication between the injection well and thirteen offset production wells indicating that the system was closed. Based on these results, it can be assumed that if the injection well were shut in after the CO_2 injection, complete and permanent geologic CO_2 sequestration could have been achieved.

Although encouraging, the only place where the Chattanooga Shale reaches the minimum depth requirement of 2600 feet is under the Cumberland Plateau, in a similar location as SRKG deep saline formation shown in Figure 3. Furthermore, the Chattanooga Shale underlying the Cumberland Plateau has a thickness on the order of 50 feet or less hindering its capacity of storing large volumes of CO_2.

Some Final Thoughts

For the most part, a state-wide assessment of the CCS potential in Tennessee has been completed using all the available subsurface geological data. Although there is still much to learn, future work should focus on site-specific geologic assessments of CCS potential. Even site-specific assessments require a substantial investment of time (years) and money (millions) and are best completed by developing partnerships with stakeholder groups, such as project developers and CO_2 emitters.

[60] Louk, et al. *Monitoring CO_2 Storage and Enhanced Gas Recovery in Unconventional Shale Reservoirs: Results from the Morgan County, Tennessee Injection Test*.

The goal of geologic characterization at a site is to produce a **conceptual geologic model** that will guide **dynamic models** used to evaluate CO_2 injectivity and assess fluid migration in the reservoir. Site-specific assessments require consistent and efficient workflows so that the reservoirs and caprocks are well defined. This includes the integration of multiple data types that include, but are not limited to:

Wireline Geophysical Logs - Advanced wireline log data is critical in the identification of reservoir facies and zones in formations that were not typically considered reservoir. Advanced wireline log data can be used to correlate to basic log data and identify key signatures that can be traced from well to well.

Whole Core Observations and Analyses - Geomechanical characterization is critical for predicting how the formation will respond to CO_2 injection and for quantifying potential geomechanical risks of long-term geologic sequestration. The geomechanical characteristics of the formation determine how CO_2 will move after injection and whether it is likely to escape the formation. Laboratory testing measurements include unconfined and confined compressive strength, and tensile strength. These tests provide information about how brittle or ductile rocks in the formation are and what magnitudes of stress can be safely maintained within the well and reservoir.

Petrophysical Properties - Porosity **-** the amount of space in the pores of the rock; Permeability **-** how well fluid can move through the rock; Lithology **-** the type of rock in the formation.

3D Seismic Imaging - Seismic analyses are critical for defining the extents and geometries of storage reservoirs. Advanced analyses can be used to track high porosity zones throughout the 3D seismic volumes. The level of effort being alluded to here is presented in the Midwestern Regional Carbon Sequestration Partnership (MRCSP) Phase III (Development Phase) Final Technical Report (Figure 5)[61]. Fortunately for us, "the core contribution from MRCSP and the other RCSP projects has been the development of a substantial body of technical knowledge and practical experience in CCS … resulting in a much greater certainty about the viability of CCS technology". "Experience in site development, project design, permitting, monitoring, and accounting for CO_2 all facilitate the development of future CCS projects."[62] Lastly, regulatory agencies and "the public will have to be satisfied that the injected CO_2 will remain in its host formation and will not escape and cause underground or surface environmental problems. Careful public education and consultation will be vital."

[61] *Final Technical Report – Midwestern Regional Carbon Sequestration Partnership (MRCSP) Phase III (Development Phase)*.
[62] For examples, see the following publications: DOE/NETL-2017/1844 (*Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects*), June 2017; DOE/NETL-2017/1848 (*Operations for Geologic Storage Projects*), August 2017; DOE/NETL-2010/1420 (*Geologic Storage Formation Classification: Understanding Its Importance and Impacts on CCS Opportunities in the United States*) September 2010; DOE/NETL-2017/1845 (*Public Outreach and Education for Geologic Storage Projects*), June 2017; DOE/NETL-2017/1846 (*Risk Management and Simulation for Geologic Storage Projects*), June 2017; and DOE/NETL-2017/1847 (*Monitoring, Verification, and Accounting for Geologic Storage Projects*), August 2017.

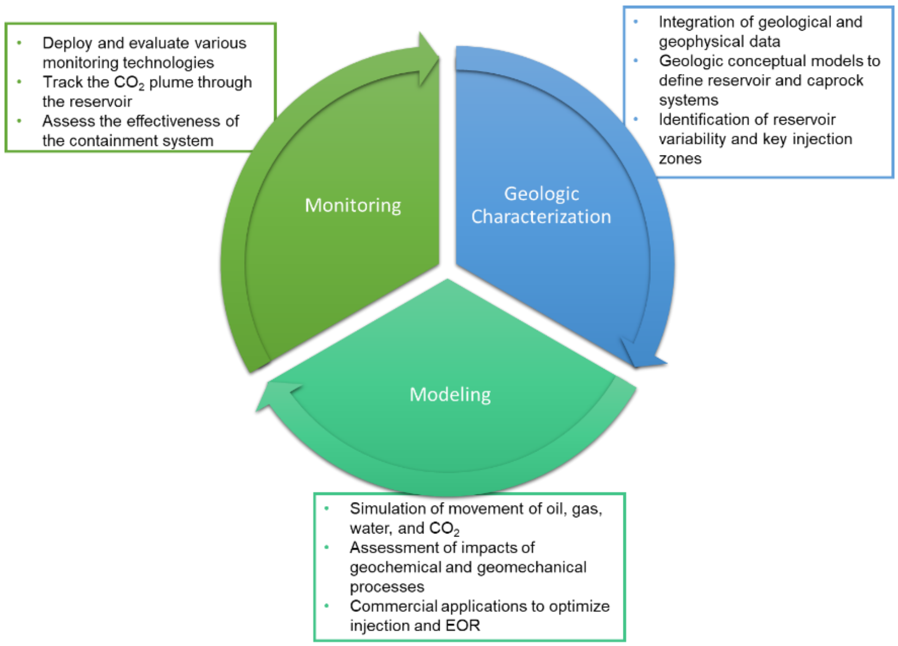


Figure 5. Major components of the large-scale injection test analyses performed on the Niagaran reefs which integrate monitoring, geologic characterization, and modeling (from MRCSP, 2020).

SPENCER J. COX
Governor

DEIDRE M. HENDERSON
Lieutenant Governor

UTAH DEPARTMENT OF COMMERCE
Division of Public Utilities

MARGARET W. BUSSE
Executive Director

CHRIS PARKER
Division Director

August 8, 2023

Submitted electronically via: https://www.regulations.gov

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2021-0527.
Mail Code 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule
Docket ID No. EPA-HQ-OAR-2023-0072; FRL-8536-02-OAR

Dear Administrator Regan,

The Utah Division of Public Utilities (UDPU) files these comments in opposition to the U.S. Environmental Protection Agency's (EPA's) proposed rule, New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (the "proposal" or "proposed rule"). The rules suffer from numerous infirmities, including reliance on unproven systems of emission reduction, an overly rosy view of compliance costs and timelines, and insufficient concern with electric system reliability, which is likely to be negatively affected by the proposed rule.

UDPU is charged with advocating the public interest in relevant forums

UDPU is tasked with "represent[ing] the public interest in matters and proceedings involving regulation of a public utility" before state and federal governmental entities. Utah Code §54-4a-1(1)(b). Utah's largest investor-owned electrical utility is PacifiCorp's Rocky Mountain Power (RMP). RMP operates in multiple states; Utah's ratepayers are affected by EPA actions on numerous RMP plants throughout the west. This includes Utah plants like the Hunter and Huntington coal facilities and the Lake Side natural gas plants, as well as coal and natural gas plants in other states. The EPA's actions will impose significant costs on RMP's customers regardless of which compliance pathway RMP chooses for each plant. Of course, environmental regulation must often impose costs to protect the public. From one perspective, environmental regulation does not impose additional costs, so much as it recognizes previously uncompensated externalities. When properly undertaken, this is appropriate. But UPDU comments today because EPA's proposal exceeds its authority in various ways and would impose costs far beyond its benefits.

EPA's carbon capture and sequestration and natural gas co-firing reductions are insufficiently proven at the scope and scale for which EPA employs them

The UDPU notes that the proposed rule's identified best systems of emission reduction (BSER) include unproven compliance options like carbon capture and sequestration (CCS) and 40 percent gas co-firing. While EPA has seemed to give states significant flexibility in complying by providing numerous options, reality suggests complying will be far more rigid than EPA admits. This is because, as the Utah Division of Air Quality (UDAQ) notes in its comments on the proposed rule, "it is not clear that a BSER of CCS with 90 percent capture has been adequately demonstrated for coal-fired steam generating units that plan to operate in the long-term." (UDAQ comments at page 2). Further, gas co-firing options may suffer from similar challenges. While not as applicable to current RMP plans, low greenhouse gas hydrogen is also not nationally available or demonstrated sufficiently.

Each system of emission reduction EPA proposes should be adequately demonstrated in order to comply with Section 111 of the Clean Air Act. EPA cannot rely on providing a menu of options to satisfy Section 111 when so many items from the menu are unlikely to be available. Even were CCS and co-firing feasible at the scales EPA alleges, numerous other problems will effectively prevent them from being employed, or from other compliance pathways proving cost effective and reliable.

Compliance is highly unlikely at the costs and times EPA requires

It is highly unlikely that the EPA's proposed rules can be implemented without significant increases in costs to Utah ratepayers. Furthermore, it is not likely EPA's timelines can be met. Recent news concerning utility additions of renewable sources and replacement of existing infrastructure is filled with uncertainty and delays in permitting, siting, supply chains, and construction. Whether because of equipment shortages, interest rate increases, or other challenges, projects are facing delays around the country and the world. These problems are likely to be even worse for speculative technologies like CCS that provide investors much less certainty than relatively proven wind or solar investments.

EPA's proposed rule will require the availability of new generation all around the country. Even if fossil-fueled sources do not retire because of the rule, their use will be scaled back in ways that require additional generation from other sources. This increase in demand, coupled with the Inflation Reduction Act's incentives are likely to increase prices for the plant needed to generate the new power.[1] These costs will be added to existing plants' costs, for which ratepayers will continue paying.

If fossil-fueled sources do not retire, their capital costs will remain in rates while new plant is added, increasing customer rates. If fossil-fueled sources do retire, their capital costs will remain in rates as utilities recover undepreciated plant balances for those investments even after they cease to provide power to customers. EPA does not properly recognize these costs in its analysis. These grow even more acute the sooner they occur because of higher existing plant balances and the likelihood that accelerated timelines will bring increased prices. All this assumes the needed additions can be made in accordance with EPA's timelines. That is unlikely.

The energy transition already underway is proceeding quickly, even in states with a higher share of fossil fueled resources. Plants once slated for 2042 retirements are now identified for replacement in 2032 in PacifiCorp's Integrated Resource Plan (IRP). UDPU is skeptical that EPA's timelines can be met. Increasingly, procurement times are growing as bidders and utilities renegotiate while interest rates rise, equipment shortages loom, and interconnection requests lag. EPA's sister agencies FERC[2] and the Department of Energy[3] have expressed concern over these developments. It seems clear that there will be costly compliance challenges and that EPA's proposed timelines will not permit states appropriate discretion under Section 111(d) to consider remaining useful life and other factors that might mitigate the EPA's political haste. This haste threatens reliability as well.

Compliance is not achievable without significant resource adequacy and reliability challenges

Electrical system reliability is imperiled further by EPA's proposed rule. Recently, both the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) have cautioned that system reliability is at risk because of an increase in variable generation sources, accelerated electrification policies, and aggressive renewable resource goals.[4] Notably, WECC's reliability assessment showed a near-term improvement in reliability between its 2021 and 2022 reports while the post-2025 risks increased.[5] The near

[1] See, e.g. "Critics warn US Inflation Reduction Act could keep prices high" Financial Times, April 23, 2023 (https://www.ft.com/content/3f8cdb59-587b-4809-80a9-1f950d0f5bce).
[2] See, e.g. Improvements to Generator Interconnection Procedures and Agreements, Federal Energy Regulatory Commission Final Rule, at 4, issued July 28, 2023 (noting "These new challenges are creating large interconnection queue backlogs and uncertainty regarding the cost and timing of interconnecting to the transmission system, increasing costs for consumers. Backlogs in the generator interconnection process, in turn, can create reliability issues as needed new generating facilities are unable to come online in an efficient and timely manner.").
[3] See, e.g. "Grid Transformer Supply Crunch Threatens Clean Energy Plans" Bloomberg Law, July 14, 2023 (https://news.bloomberglaw.com/environment-and-energy/grid-transformer-supply-crunch-threatens-us-clean-energy-plans) (noting DOE officials' concerns with workforce and supply chain shortages).
[4] See, e.g. 2022 Long-Term Reliability Assessment, NERC, at 5-8 (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf); 2022 Western Assessment of Resource Adequacy, Western Electricity Coordinating Council, at 2-3 (https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf&action=default)
[5] 2022 Western Assessment of Resource Adequacy, at 3-4.

term outlook improved by virtue of delayed retirements, while the longer-term worsening occurred because of additional variable resources paired with variability of demand at record high levels. EPA's proposed rules would worsen this picture in various ways depending on which compliance pathways states and utilities choose. Because of the aggressive timeline in the proposed rule, utilities will need to start making significant investment decisions immediately.

If the EPA finalizes the proposal without significant changes, investment in coal resources and new gas plant planning is likely to decline significantly and immediately. Utilities and states will be left to quickly evaluate if the EPA's hydrogen or CCS options are remotely feasible for their facilities and operating conditions. If, as is likely, hydrogen and CCS are not viable for them, the utilities will have an exceptionally short time frame to plan, site, permit, construct, and begin operating plants of sufficient size and capability to replace not only lost generation from retiring plants, but voltage support and other ancillary services provided by large spinning resources. It is unlikely that utilities, contractors, suppliers, and regulators can perform all the work required on the timelines EPA's proposal requires without reliability problems. As noted, NERC and WECC expressed significant reliability concerns even before this proposed rule was published. The rule exacerbates the problem.

Utility planners, aware of pressures from the EPA and other regulators, have been working to find resources that avoid many of the challenges fossil fuels present. RMP has aggressively pursued renewable resources like wind and solar, including with battery storage. The utility has conducted multiple solicitations for large quantities of resources. But those resources have a declining value the more are built and they are insufficient to sustain service. For RMP's planning, this has meant exploring new nuclear resources.

Nuclear resources are generally delayed and overbudget, if they get built at all. In any event, they are expensive. Maintaining coal and natural gas facilities sufficient to bridge the gap to operational nuclear facilities will be costly. Making capital investments to sustain operations while anticipating closure is always difficult and costly. Collecting large investments from ratepayers over the short remaining life of a plant is disruptive and collecting them long after service from the plant ceases is unfair to future ratepayers. Still, the uncertainty over the availability of a coal facility until the nuclear facility can come online is arguably risker than the expensive unfairness of an accelerated transition.

If a coal facility is bound to close to satisfy the EPA's rules but the utility has been unable to get the EPA's sister agencies to permit or site replacement facilities in a timely fashion, reliability will be threatened. This is especially the case if numerous utilities are all rushing to build in the 2027-2030 timeframe, driving availability down and prices up. If the EPA relents and allows a facility to remain operational until new facilities are ready, it will be merely expensive. If the EPA forces the closure or constrains operation in uneconomic ways, reliability problems and their associated economic losses will be even more expensive. The proposed rulemaking makes no account of these risks and costs, which go far beyond reflecting the costs of externalities and would be applied far more broadly.

The EPA should not adopt the proposed rules

As noted above, the EPA's proposed rules exceed the EPA's authority. They rely too heavily on unproven systems of emissions reduction. The proposed rules will be far more costly than the EPA acknowledges. Additionally, compliance is likely not achievable within the proposal's allowed timelines. This is especially the case when considering permitting challenges, supply chain issues, and material and personnel shortages. Enactment and enforcement of the rule as written will endanger bulk electric system reliability by depriving the system of needed generators, with their capacity, voltage support, and other characteristics, at a time when variable resources' limitations are beginning to be recognized by reliability coordinators around the country. The EPA should not adopt the proposed rules.

Sincerely,

Chris Parker
Director

State of West Virginia
Office of the Attorney General
Patrick Morrisey
Attorney General

August 8, 2023

Michael S. Regan
Administrator, Environmental Protection Agency
1200 Pennsylvania Ave NW, Suite 1101A
Washington, DC 20460

Submitted Electronically via Regulations.gov

Re: Comments on the Proposed Rulemaking Titled "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" by the Attorneys General of the States of West Virginia, Alabama, Arkansas, Georgia, Idaho, Indiana, Iowa, Kentucky, Louisiana, Mississippi, Missouri, Montana, Nebraska, New Hampshire, Ohio, Oklahoma, South Carolina, South Dakota, Texas, Utah, and Virginia (Docket No. EPA-HQ-OAR-2023-0072)

Dear Administrator Regan:

We appreciate the opportunity to comment on EPA's proposed Section 111 rule for existing coal-, natural-gas-, and oil-fired power plants. *See New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 88 Fed. Reg. 33,240 (May 23, 2023). As States, we take seriously both our traditional authority in energy regulation and our statutory role within the Clean Air Act's cooperative-federalism framework. And in discharging those responsibilities, we aim to secure reliable, affordable, and environmentally responsible energy for everyone. But we write because the Proposed Rule undermines that goal.

Only a year ago, the Supreme Court held that EPA cannot use Section 111 of the Clean Air Act to reshape the nation's electricity grids. *See generally West Virginia v. EPA*, 142 S. Ct. 2587 (2022). The Court concluded that EPA's effort to mandate "generation-shifting" brought about "an enormous and transformative expansion in EPA's regulatory authority" that Congress had never approved. *Util. Air Regul. Grp. v. EPA ("UARG")*, 573 U.S. 302, 324 (2014). *West Virginia* made plain that EPA cannot rely on Section 111(d) to "demand much greater reductions in emissions" based on its belief "that it would be 'best' if coal [and other fossil fuels] made up a much smaller share of national electricity generation." *West Virginia*, 142 S. Ct. at 2612.

The Proposed Rule at least abandons the more direct "generation-shifting" mandate that the Court rejected in *West Virginia*—but it still doubles down on the earlier rule's goals by setting unrealistic standards. If finalized, EPA's impossible proposal will leave coal- and natural-gas plants with no other option but to close. Yet EPA has no more authority to mandate this result indirectly than it did when it tried to do so directly. Thus, the Proposed Rule exceeds EPA's authority by forcing the kinds of major shifts that *West Virginia* already said can't be imposed by way of Section 111(d).

Other problems plague the Proposed Rule. For instance, the statute also forbids EPA's attempt to remove States' textually protected discretion to tailor individual performance standards for the power plants within their borders. It similarly bars "best" systems of emission reduction, like the two EPA proposes here, that lack any real-world indicia of success. And if the Clean Air Act's specific limits were not enough, general principles of reasoned decision-making also require EPA to set aside an astronomically costly rule that will make energy dangerously unreliable nationwide.

We urge EPA to reconsider.

BACKGROUND

Section 111(d) of the Clean Air Act should be cooperative federalism at its best. In it, Congress directed EPA to name "categories of stationary sources" that "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A). A stationary source is "any building, structure, facility, or installation which emits or may emit any air pollutant"—including power plants. *Id.* § 7411 (a)(3). After EPA lists a source category, it must "publish proposed regulations, establishing Federal standards of performance for new [and modified] sources within" that category. *Id.* § 7411(b)(1)(b). The CAA defines "standard of performance" as:

> [A] standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Id. § 7411(a)(1). This provision directs EPA to "determine, taking into account various factors, the best system of emission reduction which has been adequately demonstrated" (BSER) and "impose an emissions limit on new stationary sources that reflects" "the degree of emission limitation achievable through the application of the [BSER]." *West Virginia v. EPA*, 142 S. Ct. 2587, 2601 (2022) (cleaned up). Sources can generally satisfy the "emissions cap any way" they choose. *Id.*

After the EPA sets the standard for new and modified sources, it promulgates guidelines under Section 111(d) for States to submit plans setting the standard of performance for existing sources; even then, it issues those guidelines "only if [the sources] are not already regulated under" Sections 110 or 112. *West Virginia*, 142 S. Ct. at 2601. In this way, Section 111(d) "operates as a gap-filler, empowering EPA to regulate harmful emissions not already controlled under the Agency's other authorities." *Id.* (cleaned up). EPA again determines "the best system of emission reduction that has been adequately demonstrated for existing covered facilities." *Id.* at 2602 (cleaned up). But then States take over: They "submit plans containing the emissions restrictions that they intend to adopt and enforce" that reflect application of the EPA-set BSER. *Id.*

For several decades, EPA rarely deployed Section 111(d). When it exercised that power, it established a BSER through source-specific technologies and operating procedures. Things changed, however, when EPA finalized the Clean Power Plan (CPP) in October 2015. Rather than determining the BSER for existing coal power plants based on emission reductions that could be achieved at individual plants, EPA chose a novel BSER in the form of "generation shifting from higher-emitting to lower-emitting" producers of electricity. *West Virginia*, 142 S. Ct. at 2603 (quoting 80 Fed. Reg. 64,662, 64,728 (Oct. 23, 2015)). And it identified three ways a regulated plant operator could shift generation to the sources EPA preferred: reducing electricity generation; building a new natural-gas plant, wind farm, or solar installation; or purchasing emission allowances or credits as part of a cap-and-trade regime. *West Virginia*, 142 S. Ct. at 2603.

EPA set the standards so low that it was impossible for existing plants to comply using any current technologies or process improvements. The result was that EPA was effectively mandating a shift in what sources comprise the nation's power grids: EPA set the BSER so that by 2030, coal would provide "27% of national electricity generation, down from 38% in 2014." *West Virginia*, 142 S. Ct. at 2604. In short, the BSER was "one that would reduce carbon pollution mostly by moving production" to different sources, not one that would reduce emissions from the existing sources themselves. *Id.* at 2603. This BSER aimed to substitute one source of power generation for another—"to compel the transfer of power generating capacity from existing sources to wind and solar." *Id.* at 2604.

All this reorienting would have come at a significant cost. EPA admitted that the CPP would "entail billions of dollars in compliance costs (to be paid in the form of higher energy prices), require the retirement of dozens of coal-fired plants, and eliminate tens of thousands of jobs across various sectors." *West Virginia*, 142 S. Ct. at 2604 (citing EPA, REGULATORY IMPACT ANALYSIS FOR THE CLEAN POWER PLAN FINAL RULE 3-22, 3-30, 3-33, 6-24, 6-25 (2015), *available at* https://bit.ly/43SlgeT). Of course, the States most dependent on fossil-fuel-fired energy sources would have borne the brunt of the costs.

But the CPP never went effect because the Supreme Court granted a stay pending review. *West Virginia v. EPA*, 577 U.S. 1126 (2016). And EPA eventually repealed the CPP, concluding that the rule had "significantly exceeded" the agency's statutory authority. 84 Fed. Reg. 32,520, 32,523 (July 8, 2019). Specifically, EPA agreed that it never should have considered generation shifting as part of the BSER. Both Section 111's plain text and the major questions doctrine supported its revised determination, it explained, because the "generation-shifting scheme was projected to have billions of dollars of impact," and "no section 111 rule of the scores issued ha[d] ever been based on generation shifting." 84 Fed. Reg. at 32,529. EPA thus concluded that it had lacked the authority to implement the CPP because Congress did not provide a clear statement showing "[c]ongressional intent to endow the Agency with discretion of this breadth." *Id.* EPA then replaced the CPP with a different Section 111(d) rule. 84 Fed. Reg. at 32,532. That rule confirmed that a BSER should apply to specific facilities rather than at a regional or grid-wide level.

The second rule didn't go into effect either because many States and private parties filed petitions for review in the D.C. Circuit. That Court ultimately held in a 2-1 decision that EPA's "repeal of the Clean Power Plan rested critically on a mistaken reading of the Clean Air Act." *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 995 (D.C. Cir. 2021). The majority read Section 111 broadly—finding that EPA "tied its own hands" by focusing on only source-specific BSERs, *id.* at 962 n.9, and that "Congress imposed no limits on the types of measures the EPA may consider," *id.* at 946.

Last year, though, the Supreme Court reversed the D.C. Circuit, holding that EPA had been right—the second time—to reject the CPP because EPA lacked authority to require "generation shifts." *West Virginia*, *supra*. The Court noted that EPA had historically considered "measures that improve the pollution performance of individual sources" and followed a "technology-based approach" in identifying systems of emission reduction. *Id.* at 2611, 2615. But EPA abandoned that practice with the CPP, as it focused on generation shifting that would "substantially restructure the American energy market." *Id.* at 2602, 2610. The CPP was an "extraordinary case[] in which the history and the breadth of the authority that the agency ha[d] asserted, and the 'economic and political significance' of that assertion, provide[d] a reason to hesitate before concluding that Congress meant to confer such authority." *Id.* at 2608 (cleaned up). And EPA's claim of an "unheralded power representing a transformative expansion in its regulatory authority in the vague language of a long-extant but rarely used statute—one designed as a "gap filler"—meant that the major questions doctrine applied. *Id.* at 2610 (quoting *UARG*, 573 U.S. at 324).

The Court thus explained that EPA needed to "point to 'clear congressional authorization' to regulate in that manner." *West Virginia*, 142 S. Ct. at 2614 (quoting *UARG*, 573 U.S. at 324)). It couldn't: The Court found that EPA failed to show any authority establishing that the "best system of emission reduction" identified by EPA in the CPP was within the clear authority that Congress delegated in Section 111. *West Virginia*,142 S. Ct. at 2614-15. Lacking any clear statutory authority for "[a] decision of such magnitude and consequence," the Court reversed and let the CPP repeal go into effect. *Id.* at 2616.

So the Court barred EPA from adopting expansive regulations under Section 111 that would require existing power plants to engage in generation shifting. True, the Court noted that it had "no occasion to decide whether the statutory phrase 'system of emission reduction' refers *exclusively* to measures that improve the pollution performance of individual sources." *West Virginia*, 142 S. Ct. at 2615 (emphasis in original). But the decision's logic forecloses other regulatory efforts that re-interpret Section 111 in new and expansive ways—especially when they involve questions of vast "economic and political significance" that Congress could not have anticipated. *Id.* at 2623 (Gorsuch, J., concurring).

Moving ahead a year from *West Virginia v. EPA*, this Proposed Rule does exactly that. EPA is proposing two BSERs for fossil-fuel-fired plants: carbon capture and storage/sequestration (CCS) and hydrogen co-firing.[1]

CCS involves rerouting flue gas (exhaust from the electric generating unit), cooling it, and passing it through some kind of agent (like a solvent or membrane), which isolates the carbon while letting the rest of the flue gas escape. The carbon is then extracted from the agent and collected, often offsite. It is then transported somewhere else for use or long-term storage. EPA proposes that all baseload natural-gas-fired plants—that is, those operating at least at 50%—begin operating CCS systems at a 90% capture rate by 2035. 88 Fed. Reg. at 33,244. The Proposed Rule would also require all coal-fired plants without pre-2040 retirement dates to begin operating CCS systems at a 90% capture rate by 2030. *Id.* at 33,359.

For natural gas sources, EPA also proposes an alternative BSER, hydrogen co-firing. Co-firing involves adding pure hydrogen to a combustion turbine to reduce carbon emissions. Today, combustion turbines run on natural gas—though in rare circumstances operators will add a small amount of pure hydrogen. EPA proposes requiring ultra-low-GHG hydrogen at 30% by 2032 for all intermediate and baseload plants, and at 96% by 2038. 88 Fed. Reg. at 33,244.

At first blush, these new BSERs might appear to be a move away from a CPP-style generation-shifting scheme. Unfortunately, they are not. The Proposed Rule sets impossible BSERs that the industry has no chance of meeting. It would force plants to close and compel a switch to lower-emitting fuel sources such as wind and solar—making it a de facto generation-shifting mandate. So in much the same way the CPP did, this Proposed Rule exceeds EPA's delegated authority.

DISCUSSION

Last year, the Supreme Court rejected a BSER based on grid-wide production shifts because it was "an unheralded power representing a transformative expansion in [EPA's] regulatory authority." *West Virginia*, 142 S. Ct. at 2610 (cleaned up). But here we are again. The Proposed Rule bears the hallmarks of EPA's failed generation-shifting attempt. Again, EPA relies on an obscure, seldom used CAA provision to adopt an unprecedented regulation that will force a sector-wide shift in electricity production from coal and natural gas to other sources EPA thinks would better advance its policy goals. Rather than learning from *West Virginia*, this proposal doubles down on the CPP's mistakes—targeting coal and natural-gas plants for effective elimination. But that's a decision major enough for only Congress to make. And just like a year ago, the statutory text contains no clear statement showing that Congress made that call, much less tasked EPA with carrying it out.

[1] EPA is proposing six BSERs total: three for coal-fired boilers, depending on the plant's retirement date and capacity factor; one for natural-gas and oil-fired boilers; and two for natural gas combustion turbines, depending on their capacity factor. This comment letter focuses on the primary BSERs of CCS for coal and natural gas plants and co-firing for natural gas plants.

The Proposed Rule also fails under the text that *is* found in Section 111. EPA proposes two BSERs: CCS and hydrogen co-firing. But at least for now and into the near future, both are more fiction than science. Neither CCS nor co-firing hydrogen is used at utility-scale power plants in the United States, and it looks like technological limitations will prevent them from ever being widely implemented. To the extent that either technology is in limited use today, each is prohibitively expensive and faces myriad operational, transportation, and infrastructure problems. So plants won't be able to meet emissions standards premised on these impossible-to-implement BSERs. And because EPA appears to know this, it seems the Proposed Rule strives to get at the CPP's ends through another route. EPA's proposal also comes with serious unintended consequences—for example, destabilizing the energy grid at a time when demand for electricity is only increasing. All these problems mean CCS and hydrogen co-firing flunk the CAA's requirements for an "adequately demonstrated" BSER, and the Administrative Procedure Act's requirements for rational rulemaking. EPA should withdraw the Proposed Rule.

I. The Proposed Rule Violates *West Virginia v. EPA* And Exceeds EPA's Delegated Authority.

The Proposed Rule comes dressed in new clothes. But despite leaving 2015's fashions behind, it still covers an attempt to remake the nation's electricity-generation sector without clear congressional authority to take up that major task.

A. By Forcing Generation Shifting, The Proposed Rule Meddles With The Same Major Questions As Before.

A little over a year ago, the Supreme Court considered what Congress meant when it delegated EPA power to designate a "best system of emission reduction that the Agency has determined to be adequately demonstrated" for a category of stationary sources. *West Virginia*, 142 S. Ct. at 2599 (cleaned up). Noting "the ancillary nature of Section 111(d)," the Court explained that EPA had used the provision "only a handful of times since the enactment of the statute in 1970." *Id.* at 2602. And in those few pre-2015 cases, EPA had "always" looked to "measures that would reduce pollution by causing plants to operate more cleanly." *Id.* at 2599; *see also* 41 Fed. Reg. 48,706 (Nov. 4, 1976) (fiber mist eliminators installed on sulfuric acid production units); 56 Fed. Reg. 5,514 (Feb. 11, 1991) (spray dryers or dry sorbent injection); 61 Fed. Reg. 9,905 (Mar. 12, 1996) (control devices to reduce non-methane organic compounds); 62 Fed. Reg. 48,438 (Sept. 15, 1997) (scrubbers and waste disinfection technologies); 70 Fed. Reg. 28,606 (May 18, 2005), vacated by *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008) (flue gas desulfurization systems and selective catalytic reduction).

Section 111 was noteworthy to the Court for what it did not say. Consistent with EPA's decades-settled practice, the statute did not give the agency power to decide which sources should comprise the nation's power grids or how much or how little power different types of power plants should produce. The Court saw "every reason to 'hesitate before concluding that Congress' meant to confer on EPA" authority like that. *West Virginia*, 142 S. Ct. at 2610 (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159-60 (2000)). Doing so would have read too much into "merely plausible" interpretations of "vague language," allowing the agency to adopt an "unheralded" and "transformative expansion" of its delegated powers. *West Virginia*, 142 S. Ct. at 2610 (cleaned up).

So when EPA tried to read Section 111 that way anyway—making major policy judgments in the CPP rule about the ideal composition of our energy fleets and how large a shift from coal and natural gas the grids could tolerate—the Court said no. Decisions like those ones "rest[] with Congress itself, or an agency acting pursuant to a clear delegation from that representative body." *West Virginia*, 142 S. Ct. at 2616. In short, the power EPA tried to assume had all the hallmarks of a major question. Answering whether EPA could "force a nationwide transition away from the use of coal to generate electricity," *id.*, was no "ordinary case," *id.* at 2608. The "history and the breadth of the authority that the agency has asserted, and the economic and political significance of that assertion," said EPA could not tackle that issue unilaterally. *Id.* (cleaned up). Resolving the case therefore required a "different approach" in which EPA had to "point to clear congressional authorization for the power it claim[ed]." *Id.* at 2607-09. And EPA could not.

On a first pass, this new 2023 proposal might suggest that EPA has learned its lesson from *West Virginia v. EPA*. CCS and hydrogen co-firing are closer to the sort of traditional systems the agency has looked to as potential BSERs before—ways for individual regulated plants to reduce their own emissions. But a too-quick look can be deceiving. In this case, we worry intentionally so.

Start with CCS. For coal-fired units, EPA is proposing a BSER that requires 90%-capture CCS, beginning in either 2030 or 2035 (depending on operational capacity and whether the plant plans to stay open beyond 2040). 88 Fed. Reg. at 33,244, 33,359. If that type of system were technologically feasible and cost-effective, it would sound much like a technology that could lead to a "standard for emissions of air pollutants" that a particular "existing source" could meet. 42 U.S.C. § 7411(a)(1), (d). Problem is, it's not. As we explain in detail below, *infra* Part III.A., CCS technology is not ready for full-scale commercial use—and not at 90% for a couple hundred coal-fired plants within the next 8 or 13 years.

As we also explain below, the lack of real-world success for CCS anywhere close to the levels EPA wants to impose would doom the Proposed Rule under the rest of the statute. Mandating speculative technology is wishful thinking. It's different from choosing an "adequately demonstrated" system that accounts for "the cost of achieving [emission] reduction[s] and any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1). So a reviewing court can and likely would reject it on those grounds.

Major-questions analysis confirms that result. Finalizing the CCS BSER would force coal plants to shut down. Justice Kagan's dissent in *West Virginia* explained that CCS's "exorbitant costs would almost certainly force the closure of all affected coal-fired power plants." 142 S. Ct. at 2639 (Kagan, J., dissenting). Justice Kagan was wrong that mandating CCS would be legal under the CAA (setting aside the inside or outside the fenceline debate, a BSER must still satisfy the remaining statutory factors). *See Students for Fair Admissions, Inc. v. President & Fellows of Harvard Coll.*, 143 S. Ct. 2141, 2176 (2023) ("A dissenting opinion is generally not the best source of legal advice on how to comply with the majority opinion."). But she was right about the consequences of a CCS BSER: the elimination of coal-fired plants. And EPA knows it, too. The Proposed Rule concedes that it will force almost two dozen power plants to shut down and eliminate thousands of jobs by 2040. *See* EPA, REGULATORY IMPACT ANALYSIS 6-6 (2023), *available at* https://bit.ly/4592mBF. This estimate is wildly under-inclusive—if a standard is impossible to meet, more than 24 plants will have trouble with it. Relevant unions have already identified more than 273,000 direct jobs at risk from the Proposed Rule, with another 1.1 million indirect jobs associated with coal, rail, gas, and utilities further at risk. *See* Int'l Bhd. of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers, et al., Joint Union Comments on Proposed U.S. EPA Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units, at 14-15 (Aug. 4, 2023). But either way, even the EPA's low figure pushes the proposal into major-questions territory. *West Virginia*, 142 S. Ct. at 2593 ("The Government projected that the [CPP] rule would … require the retirement of dozens of coal plants, and eliminate tens of thousands of jobs.").

A 90% CCS mandate would be functionally the same as the CPP's emissions allowance that was too low for coal-fired plants to operate at their existing levels. As the Court explained, a BSER must lead to *achievable* standards—a regulated source should have a choice how to comply with the standard, but the "key" to regulation is that the limit "be no more than the amount achievable through the application of the [BSER]." *West Virginia*, 142 S. Ct. at 2601 (cleaned up). And on this score, the new BSER is worse than straight generation-shifting. After all, a coal-fired plant with an ultra-low emissions cap could still generate *some* power before hitting its limit. But under the Proposed Rule, a coal-fired plant without a 90% CCS system would be unable to generate anything after 2030 or 2035. Through an ostensibly technology-based BSER that leads to unreachable standards, EPA thus aims to impose an even more aggressive form of generation shifting in a different guise. The agency would leave operators no choice but to retire coal plants and replace their lost generation with power from other sources that are not under the same regulatory death sentence.

Hydrogen co-firing as a BSER leads to the same end. EPA would require all intermediate and baseload natural gas combustion turbines to co-fire 30% of a particular "ultra-low greenhouse gas" hydrogen by 2032—and for baseload turbines 96% of it by 2038. 88 Fed. Reg. at 33,244. All the same critiques of CCS apply to this idea, too: The technology to co-fire at 96%, along with the infrastructure to support that massive change, is non-existent. *Infra* Part III.B. Even co-firing at 30% is not an adequately demonstrated technology for existing plants (unlike, potentially, new builds, which the statute treats separately in Section 111(b)). *E.g.* 88 Fed. Reg. at 33,364 (describing two retrofitted combustion turbines that co-fire 5% and 20% regular hydrogen). So once again, finalizing this BSER would mean functional generation shifting. Natural gas plants can't keep the lights on if they must implement impossible technology to do it.

The co-firing BSER also violates *West Virginia* for a simpler reason: Wholesale fuel switching forces natural gas plants to transform into hydrogen plants. Nothing subtle or indirect about it; replacing one source with another is generation shifting, just on a single-plant level instead of grid-wide. Even the *West Virginia* dissent knew how big a deal "requir[ing] a plant to burn a different kind of fuel" could be—a BSER like that could "significantly restructure the Nation's overall mix of electricity generation." 142 U.S. at 2639 (Kagan, J., dissenting) (cleaned up). And the majority threw cold water on the idea that EPA could regulate in this way. Not only has EPA "never ordered anything remotely like that" before (another tell we're dealing with a major question, *id.* at 2608, 2610), but the Court "doubt[ed] it could." *Id.* at 2612 n.3. It's easy to see why: Section 111(d) guides States "in establishing standards of performance for existing sources," not "direct[ing] existing sources to effectively cease to exist." *Id*. (cleaned up).

In other words, existing natural gas plants must be able to comply with a Section 111(d) standard *while remaining natural gas plants*. But the Proposed Rule's fuel-switching mandate would eliminate the entire "natural gas combustion turbine" category of stationary sources by forcing the units within it to turn into something else—hydrogen plants. EPA *might* be able to squeeze past a reviewing court's eye with its initial 30% figure, assuming *Chevron* deference remains available when the agency finalizes this rule. *But see Loper Bright Enters. v. Raimondo*, No. 22-451 (U.S. May 1, 2023) (granting certiorari on *Chevron* deference). But 96% co-firing crosses the line by any measure. After all, numerous natural gas turbines can co-fire 5% hydrogen today, and some do, but no one calls those units "hydrogen turbines." The opposite is true too: Turbines firing only 4% natural gas would be hydrogen plants co-firing natural gas, not the other way around. So we see it again: Though the Proposed Rule speaks in technology-based terms, it is really regulating a category of existing sources out of existence.

For both BSERs, then, the bottom line is the same: EPA is repeating the CPP's mistakes. The consensus around CCS, for instance, is that it's a way to sub out fossil fuels for renewables. *See*, *e.g.*, Darrell Proctor, *CCS Technology Supports Coal-to-Gas Switching and Carbon-Based Products*, POWER (Dec. 1, 2021), https://rb.gy/zkzpq ("The technology is designed to facilitate the transition to natural gas-fired generation at plants making a switch from coal to gas."); Dustin Bleizeffer, *Utilities: Wyo CCUS Mandate Could Spike Monthly Bills by $100*, WYOFILE (Apr. 19, 2022), https://rb.gy/eznja ("It just doesn't make sense [to use CCS] when wind and solar are right there and so much cheaper."). Even EPA acknowledges that CCS is part of a "transition within the power sector" from fossil fuels to renewables—rather than a long-term strategy for coal plants to operate more efficiently. *Questions for Consideration*, EPA (Sept. 22, 2022), https://perma.cc/9GT9-CSXT.

Nor does it matter that the Proposed Rule tries to get to the CPP's ends a different way; the effect is what matters. Much like courts look to the "crux" of a complaint, "setting aside any attempts at artful pleading," *Fry v. Napoleon Cmty. Sch.*, 580 U.S. 154, 169 (2017), courts reviewing the Proposed Rule would look beyond how EPA couches things. Indeed, "courts have long looked to the *contents* of the agency's action, not the agency's self-serving *label*." *Azar v. Allina Health Servs.*, 139 S. Ct. 1804, 1812 (2019) (emphases in original); *see also Arizona v. Biden*, 31 F.4th 469, 482 (6th Cir. 2022) ("The content of the agency's action, not its name, shapes the inquiry."); *Meyers v. Cincinnati Bd. of Educ.*, 983 F.3d 873, 881 (6th Cir. 2020) (noting that the "substance matters more than labels"). And EPA may not do indirectly what Congress withheld power to do directly. *See PPG Indus., Inc. v. Harrison*, 660 F.2d 628, 636 (5th Cir. 1981) (striking down EPA rule that "attempt[ed] to achieve indirectly in this case what it could not do directly under the Clean Air Act: require the use of a certain type of fuel in order to comply with a performance standard").

Whatever EPA calls its new approach, the agency is still trying to "forc[e] a shift throughout the power grid from one type of energy source to another," *West Virginia*, 142 S. Ct. at 2611-12. It's hard to view "[t]he point" of this proposal as anything other than "compel[ling] the transfer of power generating capacity from existing sources to wind and solar." *Id.* at 2604. For instance, deciding "how much of a switch from coal to natural gas is practically feasible by 2020, 2025, and 2030 before the grid collapses," *id.* at 2612, is just like deciding that coal- and natural-gas fired plants need to close or become something else by 2030, 2032, 2035, or 2038. But the Court already rejected the whole way of thinking that Section 111 could be less "about pollution control" and more "an investment opportunity for States, especially investments in renewables and clean energy." *Id.* at 2611-12 (cleaned up). Again, under the statute Congress wrote, EPA doesn't get to decide "it would be best if coal made up a much smaller share of national electricity generation" or otherwise choose how "Americans will get their energy." *Id.* at 2612.

So the Proposed Rule is trying to take on the same "basic and consequential tradeoffs … that Congress would likely have intended for itself." *West Virginia*, 142 S. Ct. at 2613 (citing W. Eskridge, INTERPRETING LAW: A PRIMER ON HOW TO READ STATUTES AND THE CONSTITUTION 288 (2016)). And the results will be just as market-transforming and economy-disrupting as before. A source-selecting BSER still "fundamental[ly] revis[es]" the CAA, "changing it from one sort of scheme of … regulation into an entirely different kind." *West Virginia,* 142 S. Ct. at 2612 (cleaned up). EPA is still making nationwide "policy judgments" about "electricity transmission, distribution, and storage" without expertise in these critical areas. *Id*. And trying to remake the electricity sector—"among the largest in the U.S. economy, with links to every other sector," *id.* at 2622 (Gorsuch, J., concurring)—still has staggering "economic and political significance," *id.* at 2595 (majority op.) (cleaned up). In short, "this" rulemaking—again—"is a major questions case." *Id.* at 2610.

B. Congress Hasn't Supplied EPA's Missing Clear Statement.

Once back in the realm of major questions, EPA must "point to clear congressional authorization to regulate" in the "manner" the Proposed Rule wants. *West Virginia*, 142 S. Ct. at 2614 (cleaned up). But Congress has not revised the statute EPA is administering to give it that power.

The Supreme Court couldn't find a clear statement to bail out the agency last year. Back then, it concluded that the issues the CPP rule took up were "ones that Congress would likely have intended for itself." *West Virginia*, 142 S. Ct. at 2613. And nothing in the CAA supported EPA's claim that Congress overcame that presumption and delegated the matter instead. *Id.* at 2614. "[D]efinitional possibilities" from Section 111(a)(1)'s description of a BSER were not enough. *Id.* (quoting *FCC v. AT&T Inc.*, 562 U.S. 397, 407 (2011)). Nor were other parts of the CAA—where Congress set emissions limits or the standard for them *itself* and gave EPA broader powers than those found in Section 111 to make those limits happen. *West Virginia*, 142 S. Ct. at 2615.

Now, the Proposed Rule tries again to deploy an "ancillary provision[]" of the CAA, *Whitman v. Am. Trucking Assns.*, 531 U.S. 457, 468 (2001), in a novel and transformative way, *West Virginia*, 142 S. Ct. at 2610. But EPA is still working with the same statute. The Court noted last year that Congress had repeatedly "considered and rejected" programs like the CPP despite understanding "the dangers posed by greenhouse gas emissions." *Id.* at 2614. (This factor also helps bolster the threshold conclusion that we are dealing with a major question. *See*, *e.g.*, *Brown & Williamson Tobacco Corp.*, 529 U.S. at 159-60; *Gonzales v. Oregon*, 546 U. S. 243, 267-68 (2006).). Nothing has changed since *West Virginia*. After the decision came down, political leaders noted the need to "pass meaningful legislation to address the climate crisis." Press Release, Senate Democrats, Schumer Statement on MAGA Court's Dangerous Decision in *West Virginia v. EPA* (June 30, 2022), https://rb.gy/sky04; *see also*, *e.g.*, Press Release, White House, Statement by President Joe Biden on Supreme Court Ruling on *West Virginia v. EPA* (June 30, 2022), https://rb.gy/8nz2f ("[W]e will keep pushing for additional Congressional action."). So far at least, Congress hasn't.

Members of Congress have also expressed interest in CCS specifically. *See* Benjamin J. Hulac, *Carbon Capture, A Federal Spending Target, Has Much To Prove*, ROLL CALL (Mar. 6, 2023, 3:44 p.m.), https://rb.gy/jgs9t. But again, that interest has not become law.

Nor does the Inflation Reduction Act supply the missing clear statement. Although EPA relies on the recently passed IRA to justify the Proposed Rule's exorbitant costs (as explained below, *infra* Part III.C., unpersuasively), it does not try to rely on the IRA for new substantive regulatory power. For good reason: Congress did not amend or otherwise expand Section 111. The IRA may encourage industry players to adopt clean energy programs through tax credits, but Congress did not take the step of authorizing EPA to force industry to adopt those programs through Section 111. And any argument that Congress made an indirect change to Section 111's scope would fail, too. For one thing, implicit inferences would not satisfy the agency's burden to identify "clear congressional authorization." *West Virginia*, 142 S. Ct. at 2614. For another, Congress passed the IRA under budget reconciliation. This procedural posture means that the statute could only address appropriations—it could not "stray into non-fiscal 'extraneous' subjects." Charles Tiefer & Kathleen Clark, *Deliberation's Demise: The Rise of One-party Rule in the Senate*, 24 RWULR 45, 59 (2019).

A search for a clear statement this year yields the same result as the Court's conclusion last year: Congress's choice matters on this important issue—the "subject of an earnest and profound debate across the country." *West Virginia*, 142 S. Ct. at 2614 (quoting *Gonzales*, 546 U.S. at 267-68). At least so far, that choice is *not* to delegate. The agency therefore has no authority to finalize a rule that looks anything like this proposal. EPA should stop it now.

II. The Proposed Rule Functionally Cuts The States Out Of The Existing-Source-Regulation Process.

Beyond the major-question problems, the Proposed Rule also shuts States out of the regulatory process in way that contravenes the CAA. As the agency well knows, the Act is "a program based on cooperative federalism." *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 537 (2014) (Scalia, J., dissenting). "Down to its very core, [it] sets forth a federalism-focused regulatory strategy." *Id.*; *accord id.* at 511 n.14 (majority op.); *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1317 (D.C. Cir. 2015); 88 Fed. Reg. at 33,266. As reflected in many provisions through the CAA, Congress intended that States would ultimately play a critical role in the Section 111 cooperative-federalism framework—particularly for existing sources like those here. *See* Senator Kevin Cramer, *Restoring States' Rights & Adhering to Cooperative Federalism in Environmental Policy*, 45 HARV. J.L. & PUB. POL'Y 481, 486-87 (2022) ("cooperative federalism is expressly written into the Clean Air Act as it relates to regulating emissions from existing sources," which means States "are the lead regulators and the federal government acts as a backstop").

The CAA's central role for the States makes good sense for many reasons. A State knows its residents' needs better than the federal government. It understands its unique geographical, socioeconomic, infrastructural, and other challenges better, too. It is closer to and thus more accountable to its constituents than the federal government—and especially insulated agencies like the EPA. A State can also respond to changing conditions on the ground more nimbly and surgically than the federal government can. A State has more experience in day-to-day utility regulation. A State usually has a longtime and close regulatory relationship with most utility owners and operators. And state environmental agencies are every bit as committed, skilled, and trustworthy as their federal counterparts. *See* Alison Koppe, *Regulate, Reuse, Recycle: Repurposing the Clean Air Act to Limit Power Plants' Carbon Emissions*, 41 ECOLOGY L.Q. 349, 368 (2014) ("[Section 111(d)] regulations are a model of cooperative federalism, based on the principle that the states are the best judges of what types of emissions control regimes are most suited to local conditions."). For all these reasons and more, the CAA carefully guards state discretion and control.

In line with Congress's intent to preserve state primacy, the CAA expressly affords the States flexibility in shaping their state implementation plans for existing sources once EPA sets the BSER. EPA chooses the BSER and corresponding standard, but "the States set the actual rules governing existing power plants." *West Virginia*, 142 S. Ct. at 2601. EPA plays a limited role in approving state implementation plans, and it may issue its own plan only in the rare circumstance where a state plan proves insufficient. *Id.* at 2602. And the CAA expressly allows a State "to take into consideration, *among other factors*, the remaining useful life of the existing source" when developing its implementation plan. 42 U.S.C. § 7411(d)(1) (emphasis added). The leeway to consider remaining useful life is broad in and of itself—many of us have explained that elsewhere. *See* State of W. Va., et al., Comment Letter on the Proposed Rulemaking Titled "Adoption of and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)" 7-9 (Feb. 27, 2023), https://bit.ly/47c8bQx.

But the use of the non-exclusive term "among other factors" in Section 111(d) shows that Congress intended States to consider even more than remaining useful life. States might incorporate state-specific concerns pertaining to compliance costs, environmental considerations, energy matters, and other factors that EPA considers at the national level during the BSER stage. Or they might use their discretion to get creative in employing different ways to hit the "target" EPA sets; for instance, they might consider varying modes of operation; whether to apply rate or mass emission limits (or both); whether to incorporate a grid-reliability safety valve; whether to provide for reliability-focused "off ramps" to address extreme weather or similar events; and whether to allow reasonable compliance margins. For years, States have wielded these and other tools in the service of their communities—exactly what Congress envisioned.

The Proposed Rule turns all that upside down. True, the Proposed Rule does not purport to mandate statewide, facility-specific emission limits directly. But as further explained below, *see infra* Part III, and as we've already discussed at some length, *see supra* Part I.A, EPA has used technologically impossible BSERs to set its limit—and that choice achieves the same effect. In reality, "there is no control a plant operator can deploy to attain the emissions limits established by [the Proposed Rule]'s Plan." *West Virginia*, 142 S. Ct. at 2610. Constrained by an unduly restrictive limit produced from the "application" of imaginary technologies, States will thus be compelled to abandon their discretion and take the maximally aggressive approach EPA commands. Energy considerations and the like will necessarily fall by the wayside; facilities will need to close if the States are to implement the suffocating targets EPA proposes—and the States have no room to avoid that outcome through source-specific considerations. *See*, *e.g.*, *The US EPA's Proposed Regulation Could Help To Kill Off Fossil-Fuel Plants. Good On It*, NATURE (June 13, 2023), https://bit.ly/43QOJpI (explaining how the Proposed Rule's onerous standards mean that, "[i]n most cases" coal and other fossil-fuel plants will "shut down").

Remaining useful life itself will become an afterthought, too; no plant can be spared if EPA's numbers are to be hit. And the statute doesn't allow the rejoinder that *EPA* has taken remaining useful life into account in the BSER—like, for example, in the tiered approach to coal-fired plants based on planned retirement dates discussed above. Regulations under Section 111(d) "*shall* permit *the State* in applying a standard of performance to any particular source … to take into consideration … the remaining useful life of the existing source." 42 U.S.C. § 7411(d) (emphases added). The proposal violates this plain command in leaving no suggestion that EPA would consider state plans viable that depart from EPA's strict judgments. In fact, it says the opposite: EPA intends to "ensure that use of [remaining useful life] does not undermine the overall presumptive level of stringency of the BSER." 88 Fed. Reg. at 33,381; *see also id.* at 33,382 (stating that the agency will not let consideration of remaining useful life "undermine the overall presumptive level of stringency and the emission reduction benefits of an emission guideline, or undermine and render meaningless the EPA's BSER determination"). The proposal also reinterprets this factor to the point of making it a nonissue. The Proposed Rule already ignores significant evidence showing that CCS and co-firing are unreasonably expensive as well as technically and physically impossible; these challenges can intensify based on the facility's location, too. *See infra* Part III. But the three factors EPA says it will use to decide whether a State has appropriately employed the remaining-useful-life factor are (1) "[u]nreasonable cost," (2) "physical impossibility or technical infeasibility," and (3) "other circumstances specific to the facility." 88 Fed. Reg. at 33,382. In other words, the Proposed Rule claims to have preemptively analyzed that factor for every State and answered, "Does not apply."

And even if EPA hadn't telegraphed its answer on remaining useful life, we could still be confident that States could not satisfy EPA if they exercise their congressionally promised discretion because the agency's process makes that so difficult. EPA says that remaining useful life applies only when "a State can demonstrate that something unique to the source[] …—something that the EPA did not consider in evaluating the BSER—results in the affected EGU not being able to reasonably achieve the standard of performance." 88 Fed. Reg. at 33,382. "[M]inor, nonfundamental differences" don't count. *Id*. The only costs that could trigger relief are those that "that constitute outliers, *e.g.*, that are greater than the 95th percentile of costs on a fleetwide basis." *Id.* at 33,383. And as far as technical issues, only literal "impossibility" justifies consideration of remaining useful life. *Id.* Taken together, it's no wonder EPA thinks zero coal-fired facilities and basically no natural gas facilities will warrant relief under the factor. *Id.*

The choice to straitjacket the States in these ways will have real consequences. States will be forced to implement the sort of generation-shifting and the like that drew so much (justified) criticism in the ill-fated CPP. It will destroy States' ability to build on existing state energy programs, as no one has come close to mandating CCS or co-firing before. States have also invested broadly in renewable energy, but the Proposed Rule might make it challenging to "get credit" for those gains. So States the country over will have to realign their energy regulation plans, some several decades out. This rearrangement will cause major and long-term inefficiencies.

EPA insists that States retain flexibility because the Proposed Rule allows for things like "trading and averaging in their State plans." 88 Fed. Reg. at 33,392. Combined with the (abridged to the point of nonexistence) remaining-useful-life factor, EPA thinks this ability will provide all the flexibility and tailoring anyone could want. *See*, *e.g.*, *id.* But EPA is wrong in insisting that all is well.

Other parts of the Proposed Rule show that these promises of flexibility are illusory. Most obviously, EPA isn't willing to relax its BSERs enough to provide meaningful relief. For example, EPA says that the Proposed Rule's strictness "will likely require that certain limitations or conditions be placed on the incorporation of averaging and trading in order *to ensure that such standards are at least as stringent as the EPA's BSER*." 88 Fed. Reg. at 33,392 (emphasis added). And as we just explained, EPA doesn't think that States should have any real room to run with the remaining-useful-life discretion Congress gave them, either. In other words, States may have all the flexibility in the world—so long as they don't use it to change anything.

And by admitting that the States will likely need to fall back on trading and averaging to create plans that meet EPA's limits, the agency effectively concedes the States' major-questions-related concern: The Proposed Rule is nothing more than compelled generation shifting by another name. Plant operators will have no choice other than to pour their money into EPA's favored technologies and abandon coal and natural-gas technologies. Yet "Section 111(d) empowers EPA to guide States in establishing standards of performance for existing sources, not to direct existing sources to effectively cease to exist." *West Virginia*, 142 S. Ct. at 2612 n.3 (cleaned up).

Rejecting cooperative federalism and Section 111(d)'s express role for the States is a mistake. Like the rest of the statutory failings, EPA's choice to erase the States makes the Proposed Rule illegal.

III. Both Proposed BSERs Fail The Remaining Statutory Factors.

Even setting major-questions and cooperative-federalism concerns aside, EPA would still be on exceedingly thin ice finalizing its proposal. CCS and ultra-low greenhouse gas hydrogen co-firing—in general, and even worse at EPA's extreme percentages—fail every part of what it means for a system to be "adequately demonstrated."

The CAA tasks EPA with determining the BSER that States use to develop standards of performance for the individual existing sources within their borders. 42 U.S.C. § 7411(a)(1), (d). The "B" matters—EPA must set the "best" system according to specific metrics Congress set. *Id.* § 7411(a)(1). Congress's central requirements are that a BSER must be "adequately demonstrated" to the point that emissions standards "reflect[ing]" the BSER are "achievable"—not policy pipedreams. *Id.* This all means EPA must show that its BSER is "reasonably reliable, reasonably efficient, and … can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973). The analysis is holistic: EPA must consider *all* "significant variables." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 445 (D.C. Cir. 1980).

Congress also made sure EPA could not skip three specific factors along the way: The agency must "tak[e] into account the cost of achieving [the emission] reduction and any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1). Cost consideration mainly includes capital costs, but also considers secondary consequences like "frequent systemic shutdown to service emissions control systems." *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46. "[C]ounter-productive environmental effects" are enough to doom a BSER under the second prong. *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 385 (D.C. Cir. 1973). And energy requirements like a rule's consequences for grid reliability are especially important when, as here, EPA is regulating power plants directly. *West Virginia*, 142 S. Ct. at 2612. Courts usually balance these and other variables "cumulative[ly]"—but the case against a rule on one factor can also be "so cogent" that it clinches the analysis on its own. *Nat'l Lime Ass'n*, 627 F.2d at 431.

All told, "adequately demonstrated," "achievable," and the three enumerated factors mean that EPA must respect the line between cutting-edge and experimental technology. Again and again, courts have reminded EPA that no matter how "laudable" its "objectives" in setting a BSER, Section 111 "expressly requires" that the technology (and the emission limits flowing from it) "be achievable." *Portland Cement*, 486 F.2d at 402. And not just some of the time or under special conditions—achievable "under most adverse conditions which can reasonably be expected to recur." *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46. A BSER that ignores routine variations in conditions fails. *Id.*

Perhaps the most important tools to help decide whether a technology is appropriate for a BSER are sound studies and relevant real-world exemplars. Courts often disregard or discard tests that do not mirror real-time conditions. *See*, *e.g.*, *Essex*, 486 F.2d at 436 ("the relevancy" of certain EPA tests was "at best minimal" because the plants were running at only about half capacity were when tested). In *National Lime Association*, for example, the court remanded a rule, in part, because it appeared EPA's testing and data couldn't answer whether the proposed BSER represented "the industry as a whole." 627 F.2d at 432. EPA had also disregarded the full range of possible operating conditions, including "periods of abnormal operation," as well as all the "relevant variables that may affect emissions in different plants." *Id.* at 430, 433. And showing that a technology works outside of controlled or experimental conditions is critical, too. *Essex*, for instance, excused the fact only one plant using the proposed system existed in the United States because it had "been used extensively in Europe" for a while. 486 F.2d at 435.

That's not to say EPA can never extrapolate or predict where technology will be in the near-future—especially to respond to stakeholder concerns, particularly when it comes to *new* facilities (rather than existing ones). *Portland Cement*, 486 F.2d at 391. So using regulatory power to push current technologies a bit further ahead is not new in the Section 111 analysis. And "[b]y the very nature of its newness, it would be inevitably harder for EPA to acquire as precise and complete information about the emerging technology." *Sierra Club v. Costle*, 657 F.2d 298, 348 (D.C. Cir. 1981). But even so, the "greater the imprint of the new technology" on the BSER, "the more demanding" courts are when reviewing EPA's "evidence about the potential benefits and capabilities of new technology." *Id.* Section 111'd statutory hurdles are thus intentionally built in "difficult[ies] of justifying a standard" that prioritizes "new technology." *Id.* (explaining that to conclude otherwise would allow "circumvention of the primary statutory goals"). These hurdles should be especially high for existing sources, where sunk costs are already high.

We can see this dynamic at work in *Lignite Energy Council v. U.S. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999)—the court concluded EPA had good evidence that its selective catalytic reduction BSER would work on power utility boilers because it was already working well on industry boilers. *Id.* And EPA could answer specific concerns stemming from the different boilers' different loads because the technology was in use in a "wide range of operating conditions," fluctuating loads included. *Id.* So EPA reasonably extrapolated from known, broad, real-world examples to answer this specific objection. *Id.*

In short, *Lignite Energy* shows that EPA can take on the burden to show an emerging technology is a BSER, but that burden is heavier than normal. All the agency's predictions are subject to review, and they must all be "fair[]" projections. *Portland Cement*, 486 F.2d at 391. EPA may not set a BSER "solely on the basis of its subjective understanding of the problem" or a "crystal ball inquiry." *Essex*, 486 F.2d at 433 (cleaned up). Nor may it move ahead "on mere speculation or conjecture," *Lignite*, 198 F.3d at 934, no matter how important the underlying policy objectives. A BSER is never legitimate if it is based on "purely theoretical or experimental" technologies. *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 786 (D.C. Cir. 1976).

Unfortunately, that's what EPA proposes doing here.

A. CCS Cannot Be A BSER.

Carbon capture and storage/sequestration has been around for several decades—but it is still nascent technology and is nowhere near ready for full-scale commercial use.

The Proposed Rule would require all baseload (that is, running at least ~50% capacity) coal- and natural-gas-fired plants to begin operating CCS systems at 90% by 2030 and 2035, respectively. The "capture" part of the process works by rerouting the flue gas (the power plant's exhaust), cooling it, and passing it through a solvent or membrane to isolate the carbon while letting the rest of the flue gas escape. The carbon is extracted from the agent and then cooled and collected, often offsite. The "storage" piece means that the carbon is eventually transported somewhere else for use or long-term storage.

CCS isn't a viable BSER. The energy sector is still very much in the development phase for all aspects of the process: capture, transportation, and sequestration/storage. Even with reasonable predictions about near-future technology, it would likely be impossible to deploy CCS to the degree the Proposed Rule requires. And even if it were possible, it would be exorbitantly costly, would come with serious environmental and health side effects, and would devastate energy production nationwide. So viewed through any of the statutory factors' lenses, CCS is merely speculative—not "adequately demonstrated."

1. CCS does not work in the real world.

CCS is still an emerging technology with almost zero successful examples at all—and *no* commercial-scale examples in America's energy sector. When EPA lists many state actions taken to combat climate change, it's telling that no State mandates CCS. 88 Fed. Reg. at 33,246. This is no surprise. The Department of Energy is using money from the Infrastructure Investment and Jobs Act to fund what it calls "Demonstration Projects." DEP'T OF ENERGY, FINANCIAL ASSISTANCE FUNDING OPPORTUNITY ANNOUNCEMENT CARBON CAPTURE DEMONSTRATION PROJECTS PROGRAM (Sept. 22, 2022), https://bit.ly/3KwiYeR. Similarly, in September 2022 DOE's Office of Clean Energy Demonstrations sent out a Funding Opportunity Announcement that solicited CCS demonstration proposals. *Carbon Capture Demonstration Projects Program*, DEP'T OF ENERGY (May 15, 2023), https://tinyurl.com/27xjxwr8. The Proposed Rule admits that these and other DOE studies were commissioned "to prove feasible scalability at the industrial scale for these new technologies." 88 Fed. Reg. at 33,299. So EPA tacitly admits that CCS technology isn't ready for prime time.

This chart from the National Center for Carbon Capture's R&D team is illustrative. It estimates that the *first* CCS demonstration projects will not ramp up and become operational until late 2030 through 2032:

Southern Company, Comment Letter on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants 9 (Dec. 21, 2022), https://tinyurl.com/59zaya4c. And that's assuming no significant project delays across the decade. *Id.* Even so, the Proposed Rule would require baseload plants to have moved to a 90% CCS model before the first demonstration projects have made it across the finish line.

Some predictions and lack of exact data are fine in the Section 111(d) space. *See Sierra Club*, 657 F.2d at 348 ("By the very nature of [a technology's] newness, it [is] inevitably harder for EPA to acquire as precise and complete information."). But when EPA chooses to traffic in unknowns for a BSER, the level of review "of the evidence about the potential benefits and capabilities of [the BSER]" should be quite "demanding." *Id.* Here, CCS falls prey to all the predictable "difficult[ies] of justifying" a BSER that tries to force "new technology" on the industry. *Id.* So a reviewing court would likely find that letting EPA regulate based on the rosiest of future predictions would "circumvent [Section 111's] primary statutory goals." *Id.*

Indeed, nearly every aspect of the carbon-capture process is still back in the development phase. Start with the technology's components. When it comes to the solvents used to isolate carbon from the rest of flue gas, for membranes and fuel cells in CCS, "no field test" has "confirm[ed] that this technology is viable." *See*, *e.g.*, Southern Company, *supra*, at 26-27. Polymeric membranes and combination solvent/membrane systems show potential, but neither is ready yet even for demonstration. SHIGUANG LI ET AL., PILOT TEST OF A NANOPOROUS, SUPER-HYDROPHOBIC MEMBRANE CONTACTOR PROCESS FOR POST-COMBUSTION CARBON DIOXIDE CAPTURE (2017), https://tinyurl.com/mr2fsb9y. And solid sorbents face similar problems—they haven't yet been demonstrated at relevant scale. SHARON SJOSTROM ET AL., EVALUATION OF SOLID SORBENTS AS A RETROFIT TECHNOLOGY FOR CO2 CAPTURE (2016), https://tinyurl.com/smp46usb.

The same is true for studies and examples of the technology as a whole. Just last year one study noted that "no full-scale [natural gas combined cycle] power plants with [CCS] have been built anywhere in the world; even pilot studies using … flue gas conditions are limited," meaning little data exists "for process simulation model validation under conditions of interest for commercial … plants." W.R. ELLIOTT ET AL., BECHTEL NATIONAL, INC., FRONT-END ENGINEERING DESIGN (FEED) STUDY FOR A CARBON CAPTURE PLANT RETROFIT TO A NATURAL GAS-FIRED GAS TURBINE COMBINED CYCLE POWER PLANT (2X2X1 DUCT-FIRED 758-MWE FACILITY WITH F CLASS TURBINES) 33 (2022) ("Sherman Study"), https://tinyurl.com/7k4psybk.

Let's look at the examples EPA marshals.

Petra Nova is the onetime premier CCS facility in the United States that EPA uses as its main example. 88 Fed. Reg. at 33,293. Begun in 2017, this $1 billion CCS facility located near Houston was designed to capture 90% of the CO_2 emissions—the same target the Proposed Rule would require—from a 240-MW slip stream on a 610-MW coal-fired plant. Nichola Groom, *Problems Plagued U.S. CO2 Capture Project Before Shutdown*, REUTERS (Aug. 6, 2020, 7:45 p.m.), https://tinyurl.com/4autujp3. But in the three short years it ran, the CCS system caused plant outages around 100 days, and the plant missed its overall CO_2 reduction target by 17%. *Id.*

Petra Nova wasn't even a large project—at least not by EPA standards. *See* 88 Fed. Reg. at 33,317 (defining a plant with "a maximum of several hundred MW" as "a smaller EGU," while Petra Nova's slipstream was just 240-MW); *see also* Sam Korellis, POWER, *Utilities and Industry*

Continue Learnings Around Benefits of Heat Rate Improvement (Jan. 3, 2022), https://tinyurl.com/5s2jbcy2 (Jan. 3, 2022) (defining a "typical" coal plant as 500-MW). It also received significant federal assistance and sold its captured carbon to a facility just 80 miles away. Groom, *supra*. Even so, Petra Nova's CCS system was never economically viable—so it was mothballed in 2020 and sold a couple of years later to a Japanese company. Carlos Anchondo & Jason Plautz, *Company Sells Stake in Shuttered Petra Nova CCS Project*, E&E NEWS: ENERGYWIRE (Sept. 22, 2022, 7:15 a.m.), https://tinyurl.com/yc6x3cjk. As the Institute for Energy Economics and Financial Analysis noted in 2020, Petra Nova's closure "highlights the deep financial risks facing other proposed U.S. coal-fired carbon capture projects." DENNIS WAMSTED & DAVID SCHLISSE, PETRA NOVA MOTHBALLING POST-MORTEM: CLOSURE OF TEXAS CARBON CAPTURE PLANT IS A WARNING SIGN (2020), https://bit.ly/3s6Kp8r.

Despite this failure, EPA considers this example enough to justify CCS for coal-fired plants writ large because of lessons industry "learned" from a plant closed because of "poor economics." 88 Fed. Reg. at 33,293. But EPA never explains what is different now because of Petra Nova's example; it simply "anticipate[s]" that future facilities will get better. *Id.* at 33,291. And the only other example the proposal gives of a coal-fired plant that used CCS is a *25-MW* slip stream CCS system. *Id.* With Petra Nova already smaller than the "smaller" plants the Proposed Rule would reach, it stretches credulity that this single example one-seventh even *that* size could show that full-scale commercial deployment is "adequately demonstrated."

The lignite-fired Boundary Dam facility in Saskatchewan doesn't move the ball much, either. Its 90%-capture CCS system cost $1.5 billion and was installed in 2014 on a 110 MW unit. *See* 88 Fed. Reg. at 33,291; *Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project*, MIT, https://tinyurl.com/bmfm5cxt (last accessed Aug. 1, 2023) ("The original cost was $1.3 billion. Of that original cost estimate: $800 million was for the CCS process, with the remaining $500 million for retrofit costs."). For years it suffered from many "serious design issues," causing it to operate at 40%. Geoff Leo, *SaskPower looking for help to fix 'high cost' Boundary Dam carbon capture flaw*, CBC NEWS (May 28, 2018, 6:07 p.m.), https://tinyurl.com/mvzpjuys. This meant that in its first four years, it captured only four million metric tons of carbon dioxide equivalent. *Id*. And it paid millions in fines when it failed to hit certain benchmarks. *No more retrofits for carbon capture and storage at Boundary Dam*, CANADIAN PRESS (July 9, 2018), https://tinyurl.com/fyb28hhy. Nor were its problems limited to the first few years. In 2018, it had to call in emergency engineering help because the Shell-brand amine solution it was using—CANSOLV, which EPA plans for regulated sources to use here, 88 Fed. Reg. at 33,291—degraded twice as fast as anyone predicted. *Id.* Because of all these troubles, the Boundary Dam CCS system met its goal and captured 90% of CO_2 for the first time *eight years after installation* in the last two quarters of 2022. 88 Fed. Reg. at 33,291-92. It's probably no surprise, given all that, to see that Boundary Dam's owner refuses to add CCS systems to its other units. 83 Fed. Reg. 65,424, 65,436 n.61 (Dec. 20, 2018) (noting this refusal was, among other things, "due to high costs").

To find a natural-gas CCS example, EPA must go back more than 20 years to the Bellingham Energy Center in south central Massachusetts, which stopped operating in 2005. 88 Fed. Reg. at 33,292. And (again), that CCS system was tiny, installed on a 40-MW slip stream.

Id. The only other natural gas CCS facilities the Proposed Rule can find are in the planning stages. *Id.* EPA points to a proprietary NET Power Cycle it expects to work well, but the one system using that technology now took many years to go through just testing and grid connection, and it was only a 50-MW facility. *Id.* The Proposed Rule hesitates to use just one plant's numbers in setting the phase one BSER for intermediate load sources. *Id.* at 33,324 (not setting the rate at 1,100 lb CO_2/MWh-gross because it "is aware of a single" example of the relevant technology). EPA should exercise the same caution here.

The Proposed Rule goes against the words of caution from myriad government entities and industry players—an unsurprising outcome considering the missing real-world support for CCS at scale. Consider this sampling:

- The Congressional Research Service recognized late last year that "[t]here is broad agreement that costs for constructing and operating CCS would need to decrease before the technologies could be widely deployed." CONG. RESCH. SERV., *Carbon Capture and Sequestration (CCS) in the United States* (updated Oct. 2022) at 1, https://tinyurl.com/rmf65bry.

- The Government Accountability Office said around the same time that although capture technologies might be considered mature in some sectors, they "require further demonstration in some of the highest-emitting sectors," including "power generation." U.S. GOV'T ACCOUNTABILITY OFF., GAO-22-105274, DECARBONIZATION 3 (2022), https://tinyurl.com/xmm7vk9j; *id.* at 19 ("[t]he most mature technology (solvent-based system using amine) has only been deployed in a subset of possible configurations of coalfired power generation facilities").

- The United Nations issued a 2018 Special Report from its Intergovernmental Panel on Climate Change's 2018 Special Report that said only some modeling "suggests" CCS might be effective long term. And despite significant efforts, CCS costs refuse to "come down" (making it uneconomical), potential storage capacity remains uncertain, and whether CCS will work varies widely by region. HELEEN DE CONINCK ET AL., INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, 2018 SPECIAL REPORT 326-27 (2018), https://tinyurl.com/827skmwz.

- The Southern Company emphasizes that CCS technology is not ready, stating that it still "has not been deployed to date at commercial-scale as an environmental control technology, where reliability and consistent performance are paramount requirements." Southern Company, *supra*, at 7. It objected to EPA's waffling on which CCS technologies are "in the research, development, or demonstration stages and are not commercially available," *id.*, for not "fully describ[ing] the limitations and challenges that have been identified and encountered by the reported approaches," *id.* at 20, and for focusing on "projects that are in the planning stages," *id.* at 25. CCS still "needs to be demonstrated at a scale" well "above" where it is now "to identify and address operational issues before being considered commercially available." *Id.* at 26.

- The Institute for Energy Economics and Financial Analysis studied 13 flagship CCS facilities across seven economic sectors and found that 10 of the 13 either "failed or underperform[ed] mostly by large margins." IEEFA, *The Carbon Capture Crux* 71 (Sept. 2022), https://tinyurl.com/nhjupmbj. So history shows that using CCS technology "is a significant financial and technical risk." *Id.* at 74. And CCS's long-time "track record of technical failures" has meant that over time "90% of proposed CCS capacity in the power sector has failed at the implementation stage or was suspended early." *Id.*

- The International Institute for Sustainable Development, in summarizing 2023 Intergovernmental Panel on Climate Change work, said that "relying too much on carbon capture technology represents a major *risk* to climate safety"—it "costs too much" and in their view will not do enough anyway. IISD, *IPCC Research Shows Need for Ramping Up Mitigation Ambition, Tackling Adaptation Gaps* (Mar. 22, 2023), https://tinyurl.com/2mxz974b.

This consensus matters because it tells us that the Proposed Rule's claims that CCS can be reliable, efficient, and have low economic and environmental costs are not objectively "reasonable"—the touchstone of the adequately demonstrated analysis. *Essex*, 468 F.2d at 433. Yet despite all this, the Proposed Rule repeatedly acts like CCS is just run-of-the-mill, normal power-plant operations. *See* 88 Fed. Reg. at 33,290-98. Nothing could be further from the truth. Given the utter lack of supporting data, the industry doesn't trust or use CCS. Nicholas Kusnetz, *In a Bid to Save Its Coal Industry, Wyoming Has Become a Test Case for Carbon Capture, but Utilities are Balking at the Pricetag* (May 29, 2022), https://tinyurl.com/2ru86f5b ("Yet so far, the technology has failed to catch on commercially there or elsewhere. And many economists and policy experts say it is unlikely to play a significant role in helping eliminate emissions from the power sector."). The Proposed Rule does not give enough counterevidence to require industry to overcome these well-founded doubts—because it doesn't exist.

Instead, the agency is trafficking in the type of "mere speculation and conjecture" that Section 111 forbids. *Lignite*, 198 F.3d at 934. Setting "achievable" standards, 42 U.S.C. § 7411(a)(1), depends on "achievable" technologies. *Portland Cement*, 486 F.2d at 402 ("[Section 111] expressly requires, for the standards [the EPA] promulgates, that *technology* be achievable." (emphasis added)). And that means accounting for the "most adverse conditions which can reasonably be expected to recur." *Nat'l Lime Ass'n*, 627 F.2d at 433 n.46. But all this non-evidence shows that CCS as a BSER will not lead to "achievable" emission reductions in any case—let alone under adverse conditions. After all, Petra Nova and Boundary Dam had extensive subsidies and other advantages that most existing facilities do not. In other words, they had some of the least adverse conditions imaginable. Yet CCS still failed.

When it comes down to it, even the Proposed Rule is inconsistent in its optimism. For the first third, EPA acts like commercial-scale CCS is ready now and can be deployed by essentially any power plant. *See*, *e.g.*, 88 Fed. Reg. at 33,291 (reviewing "[v]arious technologies" and saying that industry has been "identifying and correcting [various] problems"), 33,292 ("other projects have successfully demonstrated the capture component of CCS"), 33,294 (assuming CO_2 transportation is safe because the regulatory authority has issued an "updated nationwide advisory bulletin"), 33,295 (saying geologic sequestration is adequately demonstrated based on "[e]xisting project and regulatory experience"). But then later in the rule, EPA admits that factors like needing to "deploy[] … CCS infrastructure" to handle carbon transportation and storage are why, for natural-gas combustion turbines, it chose 2035 instead of the 2030 compliance deadline it preferred. 88 Fed. Reg. at 33,304. Unfortunately, the Proposed Rule does not explain why five more years is enough to show that this currently non-existent infrastructure can get up-and-running. And it also never explains why coal-fired plants can hit the 2030 mark; perhaps EPA is indifferent towards an early compliance date when it comes to coal because that the Proposed Rule will shutter those plants before then.

This lack of evidence is ultimately fatal. The Proposed Rule points to essentially nothing that currently exists, so it cannot say in good faith that commercial-scale CCS will be "reasonably reliable" in under ten years. *Essex*, 486 F.2d at 433. The Proposed Rule is engaging in a classic crystal ball inquiry. *Id. at 434*.

And EPA knows it. Just a few years ago EPA recognized that CCS "should not be a part of the BSER for existing fossil-fuel-fired EGUs because it was significantly more expensive than alternative options for reducing emissions." 82 Fed. Reg. 61,507 61,517 (Dec. 28, 2017); *see also* 84 Fed. Reg. 32,520, 32,543 (July 8, 2019) (similar). Even the CPP said the same thing: High costs, energy impacts, geographical limitations, and other problems foreclose it as a legitimate BSER. *See* 80 Fed. Reg. 64,661, 64,728 (Oct 23, 2015). Claims that CCS costs have fallen in the past couple years, 88 Fed. Reg. at 33,245, cannot overcome the bevy of studies and resources—including those from the same period—that have confirmed EPA's prior estimates. In short, the agency knew that CCS was not a viable option as early as 2015. The only meaningful change since then is that the Supreme Court has now shut down the option EPA chose instead. But lack of other options EPA likes is not enough to make CCS adequately demonstrated.

2. Each phase of the CCS process fails Section 111(d)'s factors.

Every aspect of CCS—from the initial build to long-term carbon storage—poses severe problems for power plants. It is prohibitively expensive, hurts the environment and health, and damages energy production and reliability. So beyond CCS as a BSER failing the "adequately demonstrated" prong more generally, a reviewing court would very likely also conclude that the agency did not appropriately "consider" each of Section 111(a)(1)'s required factors.

a. <u>Building a CCS system is incredibly costly</u>.

EPA is required to "consider" "cost." 42 U.S.C. § 7411(a)(1). And a proposed system of emission reduction is not adequately demonstrated if it is "exorbitantly costly in an economic" way. *Essex*, 486 F.2d at 433. CCS is exactly that.

Let's assume to begin that a power company can find a workable CCS system that fits their specific plant. This is a dubious assumption itself: First, because of operational limitations and other variables, finding a system that works with an existing source's footprint can be challenging. The operator may not have room to install the machine since CCS systems are usually as big as the source itself—a particular challenge in more urban settings. Southern Company, *supra*, at 9 ("[C]arbon capture equipment requires roughly the same footprint as the existing combined cycle facility. Many facilities do not have sufficient space in proximity to the unit to accommodate the additional equipment and onsite space needs."). And second, natural gas units in particular face significant "technical challenges associated with retrofitting existing units with CCS technology." Edison Electric Institute, *Considerations for Clean Air Act Section 111 Regulation of Existing Natural Gas Units*, p. 3 n.4, https://tinyurl.com/2f4uw634 (last accessed Aug. 4, 2023). But those problems aside, for a plant that finds a good CCS option, the capital costs for purchasing and installing it are sky high. Last year, South Dakota and Wyoming facilities conducted a detailed study that showed that installing a 90%-capture CCS system in *just two* of their coal plants would cost about $1 billion. CHEYENNE LIGHT, FUEL AND POWER CO. & BLACK HILLS POWER, INC., APPLICATION TO ESTABLISH INTERMEDIATE LOW-CARBON ENERGY PORTFOLIO STANDARDS AND REQUIREMENTS 14 (2022) ("Wyoming Study"), *available at* https://tinyurl.com/yw98b3fz. Building the plants from scratch had cost only $300 million. *Id.* at 15.

Similarly, Bechtel National, Inc., conducted a comprehensive front-end engineering design study last year for locating an 85%-capture CCS system at a natural gas combined cycle power plant in Sherman, Texas. It estimated "[t]he overall capital cost … at $477 [million], including indirect costs, owner's and contractor's costs, and interest during construction." Sherman Study, *supra*, at 1. That price tag works out to $114.50/t$CO_2$—and even so it is based on likely "overly optimistic" estimates. *Id.* at 30; *see also id.* at Att. 1, Tbl. 1-6 (outlining various costs). Other front-end engineering design studies yield similar results. *See*, *e.g.*, Elec. Power Rsch. Inst., *Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant* 6 (Feb. 2022), https://tinyurl.com/bdhhwhz9 (estimating capital cost for the 90%-capture CCS system "to be $748 [million], with accuracy range of plus or minus fifteen percent").

Of course, these intense capital costs will be passed along to consumers. The Wyoming Study, for example, showed that capital expenses at that level would permanently increase costs by $100 a month per residential ratepayer. Bleizeffer, *supra*. That increase would double Wyomingites' monthly electric bill, which in 2021 was around $97. ENERGY INFO. ADMIN., 2021 AVERAGE MONTHLY BILL - RESIDENTIAL (Oct. 6, 2022), https://tinyurl.com/2wb35t59; *see also Wyoming 2nd Highest In Country For Energy Bills,* COWBOY STATE DAILY (July 7, 2021), https://bit.ly/45frDKn (citing an informal survey that put the number at $115/month).

Even the Proposed Rule admits that using CCS increases capital costs by 115% and incremental operating costs by 35%, leading to a levelized cost of energy increase of nearly $90/metric ton. 88 Fed. Reg. at 33,298. An 115% increase is well above reasonable levels for an agency required to consider cost: Just consider that in *Portland Cement* the overall cost increase was just 12% with annual operating costs increasing 7%. 486 F.2d at 387. And in *Lignite*, the court held that the BSER was appropriate, in part, because it would "only modestly increase the cost of producing electricity." 198 F.3d at 933. This proposal would far exceed those levels by EPA's own admission. Worse, the agency's estimates are likely low. *See* GLOB. CCS INST., TECHNOLOGY READINESS AND COSTS OF CCS 43 (2021), https://bit.ly/3Yqlh96 (cited at 88 Fed.

Reg. at 33,254 n.63, saying that CCS costs for a natural gas combined cycle unit that is not right next to storage "may cost over $120/t CO_2").

EPA tries to brush this concern away by noting that "the DOE is funding multiple projects" that are exploring how to reduce costs. 88 Fed. Reg. at 33,299. Yet again, EPA isn't sure what these studies will show—the most it can say is that some of them "*could* have reductions in capital, operating, and auxiliary power requirements and *could* reduce the cost of capture." *Id.* (emphasis added); *see also id.* (saying EPA "expect[s]" that some amine-solvent substitutions will "potentially" reduce costs by lowering auxiliary power requirements). In other words, EPA sees astronomical costs and points to studies that might—or might not—give some relief. We have no idea how much relief might result if they pan out or whether it will affect all regulated sources in each category the same rather than turning on site-specific factors at these projects. All this means that the best the agency can say is that these studies might turn into support that CCS is adequately demonstrated at some unidentified future time.

Further, plenty of historical reasons support doubting these "might's." As EPA admits, similar studies conducted 10 years ago predicted that Boundary Dam's costs would be around $95/metric ton, but its actual costs are $105/metric ton. 88 Fed. Reg. at 33,299. That EPA tacitly admits its current (and already very high) cost predictions—could be wrong by up to 10% isn't encouraging. Most troublingly though (and as detailed further below), EPA's cost estimates rely on questionably optimistic assumptions—for example, that input costs will remain static over time, or that everyone capturing carbon will be able to offset their costs by selling CO_2 or getting a 45Q tax credit. 88 Fed. Reg. at 33,300 & n.355.

All this (again) went into EPA's former conclusion that CCS could not be considered a BSER. EPA found three years ago that CCS was only *potentially* cost-effective when an affected source is *both* "in reasonable proximity to an existing CO2 pipeline—or to an EOR opportunity"—*and* received significant federal and other subsidies. EPA, RESPONSES TO PUBLIC COMMENTS ON THE EPA'S PROPOSED EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING ELECTRIC UTILITY GENERATING UNITS (EPA-HQ-OAR-2017-0355-26741), ch. 4 at 3-6 (2019), https://tinyurl.com/bdc3tw35. "[A]bsent those very specific circumstances, the EPA has concluded that CCS is not cost-reasonable, nor is it available across the existing coal fleet and cannot be considered to be the BSER." *Id.*

EPA was right then to reject CCS as a BSER—recall that emission reduction standards must be achievable "under most adverse conditions which can reasonably be expected to recur," *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46, not potentially doable in special circumstances only. It unreasonably ignores that finding now, pushing past that earlier analysis despite no real-world change or new data to justify its about face.

b. <u>The post-build capture phase is plagued by operational challenges and unjustified costs</u>.

Even if a source owner or operator manages to pay for a newly required CCS system, its problems would just be starting. *See* 88 Fed. Reg. at 33,299 (listing 14 factors associated with post-capture tasks). Take efficiency to start. CCS units run on power, too. An owner can get that power from the plant itself. But this approach makes the plant less efficient by increasing its "parasitic load"—and CCS more than triples combustion turbines' normal parasitic load. *Id.* at 33,319. This is the cause the Wyoming study analyzed that showed installing CCS technology would devastate plants' heat rates and lower net plant efficiency by 36%. Wyoming Study, *supra*, at 10-11; *see also* Sherman Study, *supra*, at 1-1 (showing parasitic load loss of nearly 10%). "[H]eat rate is the amount of energy used by an electrical generator/power plant to generate one kilowatthour (kWh) of electricity." *What is the efficiency of different types of power plants?*, ENERGY INFO. ADMIN., https://tinyurl.com/553shcpz (Sept. 20, 2022). So with heat rates, the higher the number, the more inefficient the plant.

EPA admits that, judging from one plant it reviewed, CCS increases the heat rate by 13% and parasitic load by 11%. 88 Fed. Reg. at 33,298 & n.339. Even that (perhaps optimistic) figure should stop this proposal in its tracks. Between 2011 and 2021, coal industry's collective heat rate increased by about 1.3%—and natural gas's fell by about 5.7%. ENERGY INFO. ADMIN., TABLE 8.1. AVERAGE OPERATING HEAT RATE FOR SELECTED ENERGY SOURCES, https://tinyurl.com/y6zfdymr (last accessed July 13, 2023). But based on EPA's own numbers, mandating CCS would create *ten times* the heat rate increase the coal industry suffered across the last decade. And it would set the natural gas industry back a decade, erasing its gains by a factor of two.

Heat rate inefficiencies matter because they decrease plants' overall environmental efficiency—they increase the energy consumed (and carbon emitted) per unit of power that is available to consumers. They also matter because they increase costs. Power plants must buy extra fuel to make up for increased inefficiencies and manage the extra emissions from the extra burn. One Electric Power Research Institute study found, for instance, that for a "typical" coal plant (a 500-MW EGU running at 40% capacity and firing bituminous coal), a mere "1% heat rate reduction will save about $360,000 in annual fuel costs." Korellis, *supra*. And we usually see a "one-for-one" correlation between heat rate increases and emissions—so a 1% rate improvement leads to 1% fewer NOx and CO_2 emissions. *Id.* Yet the Proposed Rule wants to go in the opposite direction, and to a degree over 10 times those 1% numbers. With just these financial and environmental costs in view, it becomes even harder for the Proposed Rule to justify CCS's steep price tag.

Alternatively, an owner can run a new CCS unit from a different power source. The Petra Nova plant, for example, installed a new, separate 75-MWh unit just to power its CCS system. This approach doesn't solve the increased costs and increased emissions problems, though: In Petra Nova CCS's first month, emissions from the 75-MWh unit erased about half of its total CO_2 reduction in a straight year-over-year comparison. *Petra Nova is One of Two Carbon Capture and Sequestration Power Plants in the World*, ENERGY INFO. ADMIN. (Oct. 31, 2017), https://bit.ly/3qc6rq1.

Beyond these operational issues, the few examples we have of CCS systems also show that equipment failures are common. In just three years of operation, Petra Nova's CCS system caused stoppages on about 100 days. *See* Nichola Groom, *Problems Plagued U.S. CO2 Capture Project Before Shutdown*, REUTERS (Aug. 6, 2020, 7:45 p.m.), https://tinyurl.com/4autujp3 (reporting that "[s]ince Petra Nova started up in 2017, it suffered outages on 367 days," and "[i]ssues with the carbon-capture facility accounted for more than a quarter of the outage days"). And as EPA notes, Boundary Dam's CCS system had a similarly poor record. What the Proposed Rule tactfully frames as "some additional challenges with availability during its initial years," 88 Fed. Reg. at 33,291, was really operating at a mere 40%—for years—because of unfixable and "serious design issues." Geoff Leo, *SNC-Lavalin-built carbon capture facility has 'serious design issues'*, CBC NEWS (Oct. 27, 2015, 7:32 p.m.), https://tinyurl.com/ynrbbt64.

Indeed, fuel-specific, unit-specific, and site-specific operational challenges are constant for CCS. *See generally* Edison Electric Institute, *supra* (focusing on unit and fuel in particular). If an owner is using a natural gas combined-cycle unit, for example, the CCS system's regenerator preheating will "lengthen startup times and limit the ability to operate at low loads." OFF. OF AIR QUALITY PLANNING & STANDARDS, EPA, AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM COMBUSTION TURBINE ELECTRIC GENERATING UNITS 40 (2022), https://bit.ly/3Kx7UOB (citing Rosa Domenichini, et al., *Operating Flexibility of Power Plants with Carbon Capture and Storage*, 37 ENERGY PROCEDIA 2729, 2731-32 (2013)). What's worse, CCS systems on these natural gas combined-cycle units must treat far more flue gas compared to coal plants, including lots of trace oxygen that the unit produces. E.J. CICHANOWICZ, AM. PUB. POWER ASS'N, 2021 STATUS OF CARBON CAPTURE UTILIZATION AND SEQUESTRATION FOR APPLICATION TO NATURAL GAS-FIRED COMBINED CYCLE AND COAL-FIRED POWER GENERATION 6 (Jan. 2022), https://bit.ly/3OKG2Jc; *see also* 88 Fed. Reg. at 33,299 (admitting that capture costs are most closely tied to the "concentration of CO_2 in the gas stream."). That's why an industrial-sized combustion turbine that operates with CCS equipment doesn't already exist. *Id.* And as for site-specific issues, a unit located somewhere with water constraints would face inordinate difficulties because a CCS unit's cooling process consumes just as much water as the plant itself—meaning water consumption ultimately doubles. EPA has treated water use as a critical factor in setting the BSER before, 88 Fed. Reg. at 33,271 (noting water-based subcategorizations in the past), yet here EPA doesn't even address the issue.

All these operational problems mean that CCS technology is neither "reasonably reliable" nor "efficient." *Essex*, 486 F.2d at 433. And the costs EPA must consider are not limited to initial build and capital expenditures: "[C]ertain 'costs'" also include second-level expenditures—such as "frequent systemic shutdown[s]" or other technology problems. *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46. Adding the second-level costs to the already exorbitantly costly initial outlays provides yet more evidence the Proposed Rule cannot rebut that CCS is not adequately demonstrated.

Piling on the statutory troubles, CCS may also have health consequences. 42 U.S.C. § 7411(a)(1). The Proposed Rule would force utilities to adopt and communities to accept all aspects of CCS technology without fully understanding the ramifications. For example, the environmental and health effects of CANSOLV—the leading amine-based and EPA-recommended CCS solvent, 88 Fed. Reg. at 33,291—appear unknown; leading CANSOLV studies over the past decade don't discuss its impact. *See*, *e.g.*, Karl Stephenne, et al., *Recent Improvements and Cost Reduction in the CANSOLV CO_2 Capture Process* (Oct. 2022), *available at* https://tinyurl.com/yhnz8vsw (focusing strictly on CANSOLV's economics); Ajay Singh & Karl Stephenne, *Shell Cansolv CO_2 capture technology: Achievement from First Commercial*

Plant, 63 ENERGY PROCEDIA 1678 (2014) (focusing only on potential applications). And because CANSOLV is proprietary, it's doubtful that we will see rigorous and independent studies about it anytime soon. Gregory K. Wanner, et al., *Chemical Disaster Preparedness for Hospitals and Emergency Departments*, 5 DEL. J. PUB. HEALTH 68 (2019) (noting that as a rule manufacturers are "hesitant to reveal the specific chemical identity of a proprietary or 'trade secret' product"); OFF. OF CHEM. SAFETY AND POLLUTION PREVENTION, EPA, RISK EVALUATION FOR PERCHLOROETHYLENE 127 (2020), https://tinyurl.com/43k24sve (saying that proprietary information's inherent secrecy can create "uncertainties in the reported data that are difficult to quantify with regard to impacts on exposure estimates" and effects). Other nascent capture technologies—like polymeric membranes, combination solvent/membranes, and solid sorbents—are just as unknown. *See* SHIGUANG LI ET AL., *supra*; SHARON SJOSTROM ET AL., EVALUATION OF SOLID SORBENTS AS A RETROFIT TECHNOLOGY FOR CO2 CAPTURE (2016), https://tinyurl.com/smp46usb.

We do know that using these technologies will have negative environmental side effects (beyond those from increased emissions from the CCS unit's power source). Nearly a decade ago, the European Union's European Environmental Agency released a study finding that CCS would increase "direct emissions of NOx and PM" by nearly a half and a third, respectively, because of additional fuel burned, and increase "direct NH_3 emissions" "significantly" because of "the assumed degradation of the amine-based solvent." EUR. ENV'T AGENCY, AIR POLLUTION IMPACTS FROM CARBON CAPTURE AND STORAGE 7 (2011), https://tinyurl.com/4b68mx99. An NIH study found that these non-greenhouse gas pollution increases would cause a secondary and "troublesome" rise in $PM_{2.5}$. Jinhyok Heo et al., *Implications of ammonia emissions from post-combustion carbon capture for airborne particulate matter*, 49 ENV'T SCI. TECHN. 5142 (2015). And worse, "[t]he public health costs of CCS NH_3 emissions" were "$31-68 per tonne CO_2 captured, *comparable to the social cost of carbon itself*." *Id.* (citation omitted). In other words, this BSER cannot "reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex*, 486 F.2d at 433.

c. Transporting captured carbon is no better.

Once the carbon is captured, we need to add transportation problems onto everything that's come before. Site location is key to CCS viability because we can only do two things with captured carbon: Use it in industry or store it. (Industry use is effectively limited to "enhanced oil recovery," or EOR, a process that pumps captured CO_2 into porous rock formations to drive out the oil trapped in the rock pores.) Either way, CCS systems typically need to be geographically near where EOR or storage opportunities are found, such as sedimentary basins, oil and natural gas fields or reservoirs, or saline formations. *Which Area is the Best for Geologic Carbon Sequestration?*, U.S. GEOLOGICAL SURV., https://bit.ly/3QuDtMQ (last accessed Aug. 5, 2023) (stating that the best storage potential is in the "coastal basins from Texas to Georgia," or Alaska and the Rocky Mountains).

So while plants in Texas and Colorado may be able to bear these costs (though not the many other costs CCS imposes as well), plants in States like West Virginia, Ohio, and Pennsylvania will see their transportation costs skyrocket as they scramble to dispose of captured carbon. The most likely option to try to comply with the Proposed Rule would be an expanded pipeline network. Petra Nova and Boundary Dam were close to EOR projects, for example—about 80 and 40 miles, respectively—and transported carbon there by pipeline. Yet while EPA has tacitly admitted before that site location is important in setting a BSER, *see* 88 Fed. Reg. at 33, 271 (noting it had categorized sources based, in part, on geographic location), here the agency all but ignores geographic location and access to CO_2 storage or use options when proclaiming that CCS is adequately demonstrated across source categories.

Let's pause for a moment at the idea that this BSER requires a new pipeline network to operate. Building pipelines usually costs a couple to several million dollars per pipeline mile. CARBON DIOXIDE PIPELINES: SAFETY ISSUES, *supra* (citing ERIC LARSON ET AL., *supra*). And pipeline construction takes more than just capital costs; regulatory and litigation costs grow the bottom line, too. Apart from significant federal regulations and permitting processes across multiple agencies, state law controls water-quality permitting and many aspects of acquiring rights-of-way. *E.g.*, 88 Fed. Reg. at 33,294 ("States are also directly involved in siting proposed CO_2 pipeline projects. CO_2 pipeline siting authorities, landowner rights, and eminent domain laws reside with the States and vary from State to State."). California, for example, recently paused transportation of CO_2 through its pipelines until the federal government updates its safety guidelines (more on that below). CAL. AIR RES. BD., FINAL 2022 SCOPING PLAN FOR ACHIEVING CARBON NEUTRALITY (2022), https://tinyurl.com/yx8388ed. EPA ignores not only the costs to build lines once all legal boxes are checked, but that unforeseen changes to state law could affect whether construction is even possible.

EPA shrugs off these transportation issues because we currently have over 5,000 miles of pipeline that can move CO_2. 88 Fed. Reg. at 33,294. For at least four reasons, it shouldn't.

First, EPA never analyzes whether that pipeline is helpfully placed—is it near current power plants? Remember, the Proposed Rule is an *existing* source rule, not best practices for new builds. And remember as well that, currently, CCS is used commercially only in non-power sector applications—so the existing pipe network isn't running to power plants. In short, the Proposed Rule gives no sense how many of those 5,000 miles of pipeline will be helpful. And it effectively admits elsewhere in the proposal that current pipeline infrastructure could *not* service "widespread" CCS. *See* 88 Fed. Reg. at 33,283 (saying that "*building* the infrastructure required to support widespread use of CCS … in the power sector will take" a long time (emphasis added)).

Second, pointing to a few private groups' press releases stating that they plan to add several thousand miles of pipeline starting in the next few years, 88 Fed. Reg. at 33,294, does not solve the transportation headache. This hope and a prayer is a wholly unsatisfying response—not just because EPA would build a rule of this scale on top of press release optimism, but because the hoped-for numbers are so paltry. "One recent [Princeton] study suggests that [a nationwide CO_2 pipeline] network could total some 66,000 miles of pipeline by 2050, requiring some $170 billion in new capital investment"—or around $2.5 million per pipeline mile. CARBON DIOXIDE PIPELINES: SAFETY ISSUES, *supra* (citing ERIC LARSON ET AL., *supra*). Several thousand miles of privately installed pipeline wouldn't bridge the gap between 5,000 and 66,000. And given that for the decade between 2011 and 2021 we added a mere 13% of our total pipeline footprint, 88 Fed.

Reg. at 33,294, it's doubtful even the minimal hoped-for expansion the Proposed Rule cites will happen anytime soon. So neither the Proposed Rule's seven-year compliance horizon nor its cost-benefit analysis sufficiently considered what a heavy—really, impossible—task readying these pipelines would be.

Third, while EPA has "solicited research proposals to strengthen CO_2 pipeline safety," 88 Fed. Reg. at 33,294, building so much so quickly poses potentially grave risks to public health. The catastrophic CO_2 pipeline failure in Satartia, Mississippi in 2020—mass evacuations of hundreds of people and 45 hospitalizations from carbon-dioxide poisoning—should be a sobering reminder before finalizing anything like this proposal. *See* Julia Simon, *The U.S. is expanding CO_2 pipelines. One poisoned town wants you to know its story*, NPR (May 21, 2023, 6:01 a.m.), https://tinyurl.com/zyr58vfs. Because carbon dioxide is odorless, clear, and heavier than air, pipeline breaches like Satartia's that release massive and heavily concentrated amounts of CO_2 can easily poison unsuspecting residents. *Id.*

Fourth, and finally, the Proposed Rule cannot trade in pure speculation to make up for any of these concerns. Recognizing that its wait-for-the-research answer is an inadequate transportation fix, for instance, EPA concludes by saying not to worry about existing pipeline space constraints because we liquefy natural gas, and CO_2 and natural gas are chemically similar. 88 Fed. Reg. at 33,294. This data- and experience-free notion about how industry *might* be able to deal with the problem—one problem of many, to be clear—doesn't cut it. *See Lignite*, 198 F.3d at 934.

d. <u>Carbon use and storage is a misnomer—neither option is viable for a significant portion of affected sources</u>.

Finally, if plants can successfully capture carbon and get it out of the plant, where to store it or how to use it are big questions marks, too.

Just a couple of years ago, the National Petroleum Council remarked that CO_2 "use is the least mature component in the CCUS technology chain." NAT'L PETROLEUM COUNCIL, MEETING THE DUAL CHALLENGE: A ROADMAP TO AT-SCALE DEPLOYMENT OF CARBON CAPTURE, USE, AND STORAGE, CHAPTER TWO: CCUS SUPPLY CHAINS AND ECONOMICS 2-7 (2021), https://tinyurl.com/2t6e5t8f. Critically, "there are significant challenges to overcome before CO_2 use technologies can be deployed at scale." *Id.* at 9-2. These include technology maturation, where "[e]fforts to bridge the gap from concept or laboratory scale to commercial-scale viability are required"; cost and energy efficiency challenges, particularly given the considerable energy needed to convert CO_2 into end-use products; and issues related to carbon's permanence and related indirect impacts. *Id.* at 9-1 to -2. Currently, "[i]ncreased investment in fundamental research and commercialization support is essential to expedite the pace at which CO_2-use technologies would be ready for commercial-scale deployment." *Id.* at 9-2. One problem is that the only viable current use of captured CO_2 is EOR: 95% of captured CO_2 is used for just that. Naomi Klinge, *U.S. representatives propose legislation that would exclude EOR from 45Q tax credits for CCS*, UPSTREAM (Dec. 15, 2021, 6:23 p.m.), https://tinyurl.com/2m9skzdc. And because EPA included no market analysis in the Proposed Rule, it cannot explain what sort of demand there might be for more carbon in EOR—*a lot more* carbon given the proposal's mandate. This failure to account enough for the "marketability of by-products" weighs strongly against finding that this BSER is adequately demonstrated. *Essex*, 486 F.2d at 439.

The proposal also must wrestle with the roadblock that some States are now moving to ban certain uses of captured carbon, including EOR. 88 Fed. Reg. at 33,264 (noting California's recent ban enacted by 2022). And States are becoming more active in this space, *id.* at 33,263-64, which means the unpredictability and volatility for approved uses of captured carbon will likely increase, not decrease. It is just this "uncertainty regarding carbon markets" that caused the DOE's last batch of CCS projects to flop. *See* U.S. GOV'T ACCOUNTABILITY OFF., GAO-22-105111, CARBON CAPTURE AND STORAGE: ACTIONS NEEDED TO IMPROVE DOE MANAGEMENT OF DEMONSTRATION PROJECTS (2021), https://tinyurl.com/3wpp6736 (saying this uncertainty "negatively affected the economic viability of coal power plants and thus these projects"). With similar factors in play now, EPA cannot credibly predict that things will turn out differently now, especially on compressed timeframes and an expanded scale.

So given the lack of use options, many owners will likely have to make do with underground storage. Again, easier said than done (even with the power of a federal regulatory mandate). For one thing, storage options are not widely distributed; acceptable storage locations require good permeability and plume. 88 Fed. Reg. at 33,300. Just a few years ago, EPA noted that over a third of States (19) have "either no/unassessed storage capacity or very limited storage capacity." *Responses to Public Comments*, *supra*. This is why storage cost estimates for CO_2 vary so widely based on location— between ~$5 and $30 a ton. *See*, *e.g.*, Erin E. Smith, The Cost of CO2 Transport and Storage in Global Integrated Assessment 35 (2021) (M.S. thesis, MIT), *available at* https://tinyurl.com/ykykv5bx; *id.* at 29 ("The cost of CO_2 storage is very site dependent because geologic characteristics vary from site to site and injection, labor, drilling, capital, and other costs vary regionally.").

The Proposed Rule provides cold comfort in response to this problem. It offers only a few examples, and they have limited storage experience (by volume). 88 Fed. Reg. at 33,295. EPA also notes a few projects still in testing—an Illinois facility started in 2017 and a North Dakota facility—and future planned projects in North Dakota and Wyoming. *Id.* at 33,295. Ultimately, no project is remotely at commercial scale because, as EPA admits, we're still "furthering the development and refinement of technologies and techniques critical to the" long-term success of storage. *Id.* at 33,295. Right now, the only large-scale sequestration project in the United States is run by the Department of Energy. CONG. RSCH. SERV., R46192, INJECTION AND GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: FEDERAL ROLE AND ISSUES FOR CONGRESS (2022), https://bit.ly/3s25NvJ.

EPA suggests some alternatives to traditional storage options, like storing CO_2 in unmineable coal seams. 88 Fed. Reg. at 33,297. This proposal is yet another idea that "has been demonstrated in small-scale demonstration projects" but never full scale. *Id.* Speculating about the possibility of using other formations like depleted oil and gas fields, *id.* at 33,297-98, is also just that—speculation. And the thought that operators could put new baseload plants near neighboring geological formations and use transmission lines, *id.* at 33,298, fails too. It ignores the "line loss" inefficiencies created whenever transmitting power over distances—a problem EPA recognizes elsewhere, *see id.* at 33,319 n.473, but not here. And it's no solution at all for existing plants that cannot change their physical location. Once again, the Proposed Rule cannot use potential options for a Section 111(b) new-and-modified source rulemaking to justify this Section 111(d) existing source rule.

Acquisition and permitting are also challenges even after (if) the industry answers the "where" problem. State law governs who owns the underground geological formations needed for storage (called "pore space" because the CO_2 settles in small voids in the geological formations called "pores"). But state legal systems governing large-scale injection into pore space are still underdeveloped. When West Virginia updated its carbon sequestration law earlier this year, for example, *see* W. Va. Code § 20-1-1–22, only a handful of other States had laws it could look to as exemplars, *see LPDD Model Law: State Legislation for the Geologic Storage of Carbon Dioxide*, LPDD, https://tinyurl.com/mrxm49tt (last accessed Aug. 5, 2023) (listing other States with CCS-related laws). The vagaries of States' laws and regulations become even more acute when dealing with large CO_2 storage projects, which could have a plume that extends for many square miles and involves many property owners. NAT'L PETROLEUM COUNCIL, MEETING THE DUAL CHALLENGE: A ROADMAP TO AT-SCALE DEPLOYMENT OF CARBON CAPTURE, USE, AND STORAGE, CHAPTER SEVEN: CO_2 GEOLOGIC STORAGE 7-35 (2021), https://tinyurl.com/4eds37m5 ("The issue of pore space legal rights is complicated by the fact that for a large CO_2 storage project, the CO_2 plume may extend over hundreds of square miles, and the pressure buildup extends over an even larger area."). The Congressional Research Service summed it up well: "[T]he transport and storage steps still face challenges, including economic and regulatory issues, rights-of-way, questions regarding the permanence of CO_2 sequestration in deep geological reservoirs, and ownership and liability issues for the stored CO_2, among others." CARBON CAPTURE AND SEQUESTRATION, *supra*.

To be sure, EPA can point to a "detailed regulatory framework" ready to approve CCS permits. 88 Fed. Reg. at 33,296. But the agency is referencing its own *federal* framework, not state law, and the word "detailed" is an understatement. This framework is EPA's Class VI well permitting process, promulgated under the Safe Drinking Water Act. *Id.* at 33,247. This permitting process is painfully slow and intensive, involving loads of documentation and many years' wait time. One article studied the timeline for a single Class VI well application: the permit application was filed in July 2011; three years later in April 2014, EPA issued a draft permit; and EPA finally authorized injection another three years after that when post-construction logging and testing and permit modification had run its course. BOB VAN VOORHEES ET AL., ILL. STATE GEOLOGICAL SURV., OBSERVATIONS ON CLASS VI PERMITTING: LESSONS LEARNED AND GUIDANCE AVAILABLE 3 (2021), https://bit.ly/3KuR0QJ. With about seven years until compliance deadlines start coming due, EPA does not explain how it expects to handle a massive new influx of permitting needs in time for regulated parties to have any assurance they can store the carbon EPA would require them to capture.

Unfortunately, the storage problems do not even stop there. Despite few examples of long-term CO_2 storage to go on, we know there have been problems. In 2011, for example, a non-power plant CCS operation that cost billions of dollars was put on hold because of concerns about the seal of the rock formation used to store the CO_2. *In Salah Fact Sheet*, MIT CC&ST PROGRAM, https://tinyurl.com/fdr76vcc (last visited Aug. 5, 2023); *see also* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CARBON DIOXIDE CAPTURE AND STORAGE (2005), https://tinyurl.com/yh94jbj2 ("CO_2 storage is not necessarily permanent. Physical leakage from storage reservoirs is possible via (1) gradual and longterm release or (2) sudden release of CO2 caused by disruption of the reservoir."). Indeed, many things can go wrong with sequestration: the pressure required to inject CO_2 and replace existing fluids can crack the geological structure; the structures are susceptible to earthquakes and other seismic activity; chemical reactions between the CO_2 and injecting chemicals can increase permeability; and CO_2 can corrode the materials used to seal old fossil-fuel wells. FOOD & WATER WATCH, FACT SHEET: CARBON CAPTURE AND SEQUESTRATION: FOSSIL FUELS' BILLION-DOLLAR BAILOUT (2022) ("FWW Report"), https://tinyurl.com/2rkxmyf2 (citing, among other sources, Adriano Vinca et al., *Bearing the cost of stored carbon leakage*, 6 FRONTIERS IN ENERGY RSCH. Art. 40, at 3 (2018); and S. Holloway, *Storage capacity and containment issues for carbon dioxide capture and geological storage on the UK continental shelf*, 223 J. OF POWER AND ENERGY 239, 241 (2008)). This isn't the picture of "reasonable reliability" that the case law demands. *Essex*, 486 F.2d at 433. And little surprise there: EPA cannot cite examples of successful, commercial, long-term CO_2 storage because they don't exist.

***

Many of these issues would sink this BSER on their own. But especially considered "cumulative[ly]," they establish that CCS is not adequately demonstrated. *Nat'l Lime Ass'n*, 627 F.2d at 431. Just consider the confluence of similar issues that confronted the court in *Sierra Club*—the "inherent tension" between pushing "innovative" technology and "adequately demonstrated" technology. 657 F.2d at 341 n.157. Like the dry scrubbers there, CCS may offer "potential advantages" over other greenhouse-gas-reduction technologies. *Id.* But also like dry scrubbers, CCS leaves us with too many unanswered questions like how the technology will work and how much it will cost. These open questions "limit the overall acceptability of" CCS and strongly indicate that it hasn't been adequately demonstrated. *Id.* Worse still, here (like there) "no full scale" examples of the chosen technology are "presently in operation at utility plants." *Id.* EPA bore a heavy burden in *Sierra Club* to explain how its "limited" pilot and prototype testing data could "predict performance in full scale plants throughout the industry." *Id.* All that created "major uncertainty" for about whether dry scrubbing was ready for primetime—and the reviewing court readily said it was not. *Id.* So too with CCS: With sizable questions plaguing every stage of the process, it is not one of those rare emerging technologies that could "conceivabl[y]" be adequately demonstrated. *Id.* EPA should discard it now.

B. Co-firing Is Not A Statutorily Permissible BSER, Either.

As the agency knows, the fuel used in combustion turbines today is overwhelmingly natural gas. Sometimes, operators will add a little pure hydrogen to the natural gas—a process called "co-firing." This can be attractive from an environmental efficiency standpoint because natural gas's chemical structure includes carbon, while pure hydrogen's doesn't. EPA is proposing to require all intermediate and baseload combustion turbines to start co-firing 30% hydrogen by 2032 and baseload combustion turbines to co-fire 96% hydrogen by 2038. The Proposed Rule would also require natural gas plants to buy and burn "ultra-low greenhouse gas hydrogen"—not the hydrogen currently on the market.

Understanding the two types of combustion turbines on the market today and the hydrogen manufacturing process help clarify hydrogen co-firing's significant challenges as a BSER. The first combustion turbine technology is the older diffusion technology, which compresses air, puts it into a combustion chamber, and then adds the fuel and water to the chamber via separate nozzles. (The water is supposed to cool the reaction to ~2600 degrees, the temperature sweet spot for limiting NOx and carbon monoxide emissions.) These systems are expensive. And because of demineralized water requirements, their usefulness is limited in arid locations, like in most of the western States. But on the plus side they have great fuel flexibility. The second technology—the far more common one used today—is the newer dry-low-nitrogen (DLN) approach, which uses staging to premix the compressed air and fuel before they reach the combustion chamber. Premixing slows down the chemical process, leading to less intense flame and heat and therefore less NOx. But DLNs lack operational and fuel flexibility. For its part, hydrogen is manufactured in several ways: methane pyrolysis, reforming/ gasification, and electrolysis. For purposes of its second BSER, the EPA is proposing electrolysis as the relevant manufacturing method because it is the only one that's greenhouse gas free. To oversimplify, electrolysis creates pure hydrogen by separating water molecules' hydrogen and oxygen atoms. But this process is resource-intensive, costing twice the energy we get from burning the pure hydrogen. So the only way the Proposed Rule explains to prevent the BSER from being environmentally counterproductive is to mandate that the hydrogen be produced using ultra-low greenhouse gas methods—that is, with renewable energy.

As explained above, this BSER far exceeds EPA's statutory mandate because it doesn't regulate natural-gas plants as much as require them to become something else entirely—a hydrogen-fired plant. It also goes "beyond the fence line" by claiming most of the proposal's benefits from the way hydrogen is *produced*, not anything about how the power plant itself burns it. Mandating ultra-low greenhouse gas hydrogen as an input is not an "efficiency-improving, at the source measure[]," *West Virginia*, 142 S. Ct. at 2612 n.3, because burning hydrogen emits the same emissions regardless how it's produced—the Proposed Rule's reductions occur during the off-site production process. *See* Emre Gençer, *Hydrogen*, MIT CLIMATE PORTAL (June 23, 2021), https://tinyurl.com/3eu9nvpc ("Unlike most fuels, hydrogen does not produce the greenhouse gas carbon dioxide (CO_2) when burned: instead, it yields water.").

For purposes of the rest of the statutory requirements, it also shares the key flaw that CCS does: Co-firing with hydrogen at anything approaching commercial scale is unheard of. Edison Electric Institute, *supra*, at 5 ("[C]urrently there is a lack of operating [co-firing] projects at scale, both in the United States and abroad, as well as critical open U.S. regulatory, legal, and commercial questions."). So here too, courts will give a "demanding" look at EPA's purported "evidence about the potential benefits and capabilities of [co-firing]." *Sierra Club*, 657 F.2d at 348. And also like CCS, co-firing falls prey to all the predictable "difficult[ies] of justifying" a BSER that does not reflect existing technology but tries to force industry to develop and then use "new technology." *Id.* (saying allowing that sort of BSER would "circumvent[Section 111's] primary statutory goals").

Hydrogen co-firing cannot meet that demanding level of review. To start, just like CCS, little evidence and data supports co-firing as a BSER. The combustion turbines themselves have serious technological limitations—such as co-firing capacity and flashback—and the proposal ignores these problems. Moving past the turbines, it's difficult to see how industry could manufacture enough hydrogen to meet EPA's co-firing goals. And even if it could, it could not transport the hydrogen to the natural gas plants given critical pipeline and storage limitations. All these and other problems have put the economic cost of hydrogen through the roof—an issue that would get exponentially worse considering the other challenges from using the ultra-low greenhouse gas hydrogen the Proposed Rule mandates. And after all this headache, the environmental benefits are far below promised levels. The Proposed Rule does not adequately respond to any of that. Co-firing fails every Section 111(a)(1) factor and thus cannot be a best system of emission reduction.

1. No studies or other evidence adequately demonstrate that hydrogen co-firing is a legitimate BSER.

Hydrogen co-firing is even more embryonic than CCS; to call it "emerging" would give it too much credit. The Proposed Rule sometimes seems to recognize this—like when summarizing industry as having only "a growing interest in the use of hydrogen as a fuel." 88 Fed. Reg. at 33,255. But the gulf between a "growing interest" and an adequately demonstrated technology is huge. "By the very nature of its newness, it [is] inevitably harder for EPA to acquire as precise and complete information about [co-firing] technology" as necessary to choose it as a BSER. *Sierra Club*, 657 F.2d at 348. The Department of Energy recently set out in detail just how undeveloped it currently is. *See* DEP'T OF ENERGY, U.S. NATIONAL CLEAN HYDROGEN STRATEGY AND ROADMAP (2023), https://tinyurl.com/bdzjvdd4. On the ultra-low greenhouse gas hydrogen side of things, for instance, DOE says that the key "components and integrated systems" used to make it "are still in the early stages of scale-up and commercial deployment." *Id.* at 24. Even more concerning, we also don't know hydrogen's "most suitable applications" and "optimal use[s]" within the broader "overarching energy systems." *Id.* at 26. And EPA knows all this because it "consulted with the DOE" on this Proposed Rule. 88 Fed. Reg. at 33,247. Its decision to designate hydrogen co-firing a BSER is thus even more confusing. EPA simply cannot make a fair prediction of cost, reliability, efficiency, and other statutorily required considerations when this technology is still in its earliest stages.

Indeed, the too-limited state of hydrogen co-firing is obvious from the weak co-firing exemplars the proposal offers up. Its primary example is a transition from coal to natural gas, not the technology EPA proposes to require. *See* 88 Fed. Reg. at 33,305. Its second example isn't an example of co-firing at all; it's just a source "designed to transition to 100 percent hydrogen in the future" (and that right now can still co-fire only 5%). *Id.* at 33,305. And scraping the bottom of the barrel, the proposal notes that the New York Port Authority once co-fired 44%. *Id.* at 33,305. None of these short-term or one-time demonstrations are relevant here: for Section 111 purposes, tests must be at least somewhat similar to real-world conditions. *Sierra Club*, 657 F.2d at 341 n.157. Otherwise extrapolating from outliers misses important factors—like long-term damage to combustion turbines from sustained and extensive co-firing.

Yet EPA can point only to "plans" and "projects," "plans to collaborate," and intentions to "begin" construction in this area. 88 Fed. Reg. at 33,305-06. The Proposed Rule lacks real-world evidence or data, leaving just more forbidden speculation and conjecture. *See Lignite*, 198 F.3d at 934. Its proposed plans to manufacture co-firing technology *and* transmission *and* infrastructure tells us that none of these stages of hydrogen co-firing are ready at a commercial scale. 88 Fed. Reg. 33,306. In trying to justify its unreasonably high 30% co-firing number, for instance, EPA cites several manufacturers who say they will make combustion turbines that can co-fire at high numbers. Of course, there's a significant difference between manufacturers predicting they will be able to build a 100% co-firing combustion turbine, *id.* at 33,308, and evidence that concrete, realistic plans exist to do so soon and at scale. The *only* power plant EPA cites that has a concrete plan to get to 100% co-firing says it won't be there technologically until 2045—seven years too late for EPA. 88 Fed. Reg. at 33,308. This lack of evidence puts co-firing firmly in the "purely theoretical or experimental" technologies category. *Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 786.

2. Co-firing is plagued by technological limitations.

We don't see co-firing on anything approaching the level the Proposed Rule would require for a reason: Combustion turbines can't handle the co-firing numbers at EPA's preferred level, and there's no concrete evidence they will be able to, either. Start with the initial requirement to burn 30% hydrogen by 2032. Most combustion turbines on the market today cannot handle anything more than a 5-10% blend; 20% is generally accepted as the absolute technological ceiling. A. Aniello et al., *Hydrogen substitution of natural-gas in premixed burners and implications for blow-off and flashback limits*, 47 INT'L J. OF HYDROGEN ENERGY 33,067, *2 (2022) ("burners designed for natural gas, can only sustain limited hydrogen concentrations, typically 5 to 20% [volume] in the fuel blend"). Even in the best scenarios, a hydrogen volume fraction of 20% is usually the most technology currently can do. *Id.* EPA's 2038 target of 96% hydrogen co-firing fares even worse, because "the highest hydrogen capability marketed for any frame engine with lean premixed combustion is 50%"—and for most systems that percentage is "much lower." Ben Emerson et al., *Hydrogen substitution for natural gas in turbines: Opportunities, issues, and challenges*, POWER ENG'G (June 18, 2021), https://tinyurl.com/bdcmxc8x. Technological impossibility drives to the heart of Section 111's adequately demonstrated standard: If sources cannot burn at the level EPA has set, then the BSER fails on that ground alone. Indeed, *Essex* said that sources must at the very least be able to "approach[]" the BSER EPA establishes, 486 F.2d at 440; no hydrogen co-firing technology we have now comes close.

In its more candid moments, EPA seems to acknowledge the deep uncertainty this proposal faces—exactly how much hydrogen can these combustion turbines handle. 88 Fed. Reg. at 33,244. The Proposed Rule insists in some places that 30% is achievable, *id.* at 33,255, but in others contradicts itself, admitting that we're still only at the demonstration phase of firing 20%, *id.* at 33,305. EPA fails to resolve the tension in these statements. And it begrudgingly acknowledges the massive difficulties inherent to co-firing in DLN combustion turbines, but it tries to brush away these problems by saying it is sure the market is developing a solution, *id.* at 33,311, and then listing various utilities that have publicly announced a desire to burn 100% hydrogen by 2035 to 2045, *id.* at 33,255. But with all EPA's evidence tallied, here is what the Proposed Rule cites to support its co-firing goals: "three utility announcements" and "several"—three—"merchant generators … signaling their intent to ramp up hydrogen co-firing levels." *Id.* at 33,255. A handful of industry desires is not enough to confidently say co-firing is the *best* system of emission reduction. *See Lignite*, 198 F.3d at 934.

At other times, the Proposed Rule misrepresents how much hydrogen combustion turbines can currently co-fire. For example, EPA says that by 2030 manufacturers "will be capable of combusting 100 percent hydrogen" using DLN designs. 88 Fed. Reg. at 33,312. Yet the evidence for this aggressive claim is a single quote from a single article, *id.* at 33,312 n.443, in which a GE executive says the company would continue investing in R&D "to advance the percentage of hydrogen combustion capability *towards* 100% by 2030." Frédéric Simon, *GE eyes 100% hydrogen-fuelled power plants by 2030*, EURACTIV (May 12, 2021), https://tinyurl.com/3zaa9cyy (emphasis added). Indeed, the article's cautious title—that one company is merely "eye[ing]" 100% hydrogen co-firing—gives the game away. So EPA's prediction on perhaps the most fundamental question for this BSER—whether co-firing at the prescribed levels is even technologically feasible—is built on the flimsiest of foundations.

Combustion turbines also face many operational challenges, with two particularly relevant here because hydrogen makes both worse. First is "flashback"—when the flame in the combustion chamber begins traveling up the fuel stream towards the source. 88 Fed. Reg. at 33,311. Hydrogen's flame speed is an order of magnitude greater than natural gas's. So hydrogen flame tends to propagate upstream much faster and can damage certain hardware (the injection system) that would never be in danger if natural gas were the fuel. Aniello et al., *supra*, at *11; KEVIN TOPOLSKI ET AL., NAT'L RENEWABLE ENERGY LAB., HYDROGEN BLENDING INTO NATURAL GAS PIPELINE INFRASTRUCTURE: REVIEW OF THE STATE OF TECHNOLOGY 39 (2022), https://tinyurl.com/4xnakzhs. "Boosting the hydrogen content" to about 50% raises the burner temperature by a third, brings the flame "dangerously" close to the burner, and then causes flashback. Aniello et al., *supra*, at *20. Second, combustion instabilities in modern, low NOx turbines make them prone to many kinds of damaging oscillations during operation, and these oscillations are highly sensitive to ambient air temperature and fuel composition. Introducing hydrogen as a new fuel source will, in many turbines, increase those combustion instabilities that can take a natural-gas plant offline. *Id.* at *2 ("[A]dding hydrogen to standard fuels poses challenges, since it modifies fundamental combustion characteristics that can compromise the fulfillment of safety and pollution standards" (cleaned up)). Both these issues are serious—flashback is a common and well-known problem, and it's one of the "adverse conditions which can reasonably be expected to recur" when co-firing. *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46. The Proposed Rule should have an answer to both concerns to get past the "adequately demonstrated" hurdle. It doesn't.

Another technological limitation: current hydrogen co-firing technology requires a far higher number of manual interventions to keep the hydrogen fuel supply steady than is ideal for plant operations. *See* ELECTR. POWER RSCH. INST. ET AL., EXECUTIVE SUMMARY: HYDROGEN COFIRING DEMONSTRATION AT NEW YORK POWER AUTHORITY'S BRENTWOOD SITE: GE LM6000 GAS TURBINE (2022), https://bit.ly/3Yp5w23. This constant need for intervention is a serious operational problem in and of itself. But it becomes far more acute because DLN combustion turbines are highly sensitive to differences in fuel mixture; in short, co-firing threatens DLN turbines' stability. *Id.* Co-firing also requires many parts of the combustion turbine to be readjusted. *See*, *e.g.*, *id.* (noting that co-firing with hydrogen means the natural gas fuel pressure must increase significantly). And these readjustments create many opportunities for turbines to fail; the Proposed Rule ignores this crucial aspect of its cost analysis, too. All these operational challenges mean that co-firing isn't reasonably reliable or reasonably efficient. *Essex*, 486 F.2d at 433.

3. Sourcing and transporting ultra-low greenhouse gas hydrogen faces serious headwinds.

Yet another reason this BSER hasn't been adequately demonstrated is inadequate fuel supply. By all accounts, it will be nearly impossible for plant operators to get and move enough ultra-low greenhouse gas hydrogen to both comply with the Proposed Rule *and* keep America's lights on.

To start, we have no hydrogen—let alone enough ultra-low greenhouse gas hydrogen—that could meet this BSER. *See* Edison Electric Institute, *supra*, at 6 (noting that EPA should reconsider this BSER "once hydrogen is available as a fuel"). Consider what it would take to replace the natural gas burned in combined cycle units with hydrogen. In 2021, natural gas accounted for 38% of total energy production. See Elizabeth Weise, *Here comes the sun: Wind, solar power account for record 13% of U.S. energy in 2021*, USA TODAY (March 5, 2022), https://tinyurl.com/9tf7pr4d. And combined cycle turbines accounted for 32% of total energy production. EIA, *U.S. electric-generating capacity for combined-cycle natural gas turbines is growing* (Nov. 4, 2022), https://tinyurl.com/yckahkk5. This figure means that combined cycle units consumed roughly 84% of all natural gas burned by the energy sector in 2021. Last year, our nation's energy sector burned 12.12 trillion cubic feet of natural gas. *Natural gas explained*, ENERGY INFO. ADMIN. (Apr. 28, 2023), https://tinyurl.com/4wcnev6m. So combined cycles burned roughly 10.2 (84% of 12.12) trillion cubic feet of natural gas. One cubic foot of natural gas produces 1,036 BTUs, meaning combined cycles produced around 10.6 quadrillion BTUs of energy. How much hydrogen would we have to burn? Our entire hydrogen production—10 million metric tons—is "equivalent to just over 1 quadrillion BTUs per year." https://tinyurl.com/yc58e6zd (Oct. 7, 2021). And 95% of that 10 million metric tons isn't the sort of clean hydrogen that counts for the Proposed Rule. 88 Fed. Reg. at 33,306. In short, America currently produces just .5% of the clean hydrogen we need under the Proposed Rule. The industry would have to close a 99.5% supply gap in just 15 years.

EPA has offered no evidence showing that this gap will close. "Nearly all of" the 10 MMT we produce we use for "refining petroleum, treating metals, producing fertilizer, and processing foods." *Hydrogen Production and Distribution*, DEP'T OF ENERGY, https://tinyurl.com/mtctydav (last accessed Aug. 5, 2023). And industry could not use even the very little left over to comply with the Proposed Rule because it is not the ultra-low greenhouse gas variety EPA prefers. DOE estimates that the market will create 10 additional million metric tons of clean hydrogen by 2030 and 20 total by 2040. 88 Fed. Reg. at 33,309. This amount seems marginally hopeful, but the Proposed Rule doesn't given enough to assess the prediction because it does not explain how DOE gets there. What's worse, even these numbers are possibly irrelevant because EPA is not sure that what DOE calls "clean" hydrogen means the ultra-low greenhouse gas hydrogen it proposes requiring. *Id*. And on top of that, even 20 million metric tons of ultra-low greenhouse gas hydrogen is still just a fifth of our total combined cycle natural gas need—let alone 15 years from now as the electrification trend continues. It's hard to believe that closing this minimum 80% gap would be anything but "exorbitantly costly." *Essex*, 486 F.2d at 433.

EPA admits that "building the infrastructure required to support widespread use of … low-[greenhouse gas] hydrogen in the power sector will take" a long time. 88 Fed. Reg. at 33,283. But this language appears to be code for trying to manufacture an industry from scratch and then propping it up with federal money. America doesn't make much hydrogen, and of what we do make, only 5% fits EPA's definition of ultra-low greenhouse gas hydrogen. *Id.* at 33,306. Indeed, "[o]nly small-scale facilities are currently producing hydrogen through electrolysis." *Id.* at 33,312. EPA also is not just mandating that intermediate and baseload combustion turbines use ultra-low greenhouse gas hydrogen—it proposes defining ultra-low greenhouse gas hydrogen to exclude any hydrogen that comes from a facility that manufactures non-low greenhouse gas hydrogen. *Id.* at 33,328. This distinction means that the existing small hydrogen producers cannot just retool part of their plants or expand their plants to make clean hydrogen; they would have to convert the entire plant. So building an industry from scratch as the proposal would require seems unlikely. Once more, the almost certain lack of hydrogen is one of those "significant variables" that shows a BSER cannot be "adequately demonstrated." *Nat'l Lime Ass'n*, 627 F.2d at 445, 450.

Co-firing also runs into many of the same transportation and infrastructure hurdles as CCS. Pipelines are probably the biggest issue (though the concerns below apply to any infrastructure we use to ship hydrogen, including trucks, trains, and ships). We currently have only 1,600 miles of hydrogen pipeline. 88 Fed. Reg. at 33,308. Compare that to our *300,000 miles* of natural gas transmission pipeline. *Annual Report Mileage for Natural Gas Transmission & Gathering Systems*, DEP'T OF TRANSP. (July 10, 2023), https://tinyurl.com/43j6nmy9. Even if we had enough pipelines, we'd first run into energy inefficiencies caused by "compression" issues—what one veteran chemical engineer working for the Hydrogen Science Coalition called the hydrogen-as-fuel-source "deal killer." Paul Martin, *Is Hydrogen The Best Option To Replace Natural Gas In The Home? Looking At The Numbers*, CLEANTECHNICA, https://tinyurl.com/325j36x7 (Dec. 14, 2020). Before any gas can be moved, it must be compressed. *Id.* Generally, "dense gases are easier … to move than less dense ones." *Id.* Hydrogen is much less dense than natural gas and thus harder to compress. *Id.* So difficult, in fact, that "it takes about *three times as much energy* to compress a MJ's worth of heat energy" in hydrogen than it does in natural gas. *Id.* (emphasis added). And this compression uses not just more energy, but it creates additional capital costs as gas utilities replace or purchase far more powerful and expensive compressors. *Id.* These differences explain why, in part, "we don't move hydrogen around much by pipeline"; in Europe, for example, 85% of hydrogen produced "travels basically no distance to where it's consumed." *Id.*

And what's worse, we can't use the existing natural gas pipeline infrastructure because of a phenomenon called "embrittlement": Hydrogen is the "smallest size molecule that exists," and is quite diffuse (meaning as a molecule it easily breaks apart into its constituent hydrogen atoms).

JEAN-FRANÇOIS LIBERT & GARY WATERWORTH, UNDERSEA FIBER COMMUNICATION SYSTEMS (2d ed. 2016). These characteristics allow hydrogen to permeate hard pipeline metals and plastics much faster than larger, less diffuse molecules like methane-based natural gas. CONG. RSCH. SERV., R46700, PIPELINE TRANSPORTATION OF HYDROGEN: REGULATION, RESEARCH, AND POLICY (2021), https://bit.ly/3OqLBem (saying hydrogen "can also permeate directly through materials used for natural gas distribution faster than methane"). Over time, the hydrogen inside the pipeline microstructure begins causing hairline cracks that, with more time, grow larger. *Hydrogen embrittlement: what is it and how to prevent it?*, DEMACO, https://tinyurl.com/mtchc7f2 (last accessed Aug. 6, 2023). Eventually, if the pipeline isn't replaced, this embrittlement can cause breaks, leaks, or explosions. *Pipeline Transportation of Hydrogen*, *supra* ("Hydrogen can deteriorate steel pipe, pipe welds, valves, and fittings through embrittlement and other mechanisms.").

We know we can send some hydrogen through natural gas pipelines safely—say 1-5% of the total pipeline load. *See* California Public Utilities Commission (CPUC) & University of California, Riverside, *Hydrogen Blending Impacts Study* 107 (July 18, 2022), https://tinyurl.com/4c55hnd4. But once we get to 20%, things get dangerous: Hydrogen blends higher than 20% "increase the risk of gas ignition outside the pipeline." CAL. PUB. UTILS. COMM'N, HYDROGEN BLENDING IMPACTS STUDY 107 (2022) ("CPUC Study"), https://tinyurl.com/4c55hnd4; *see also* PIPELINE TRANSPORTATION OF HYDROGEN, *supra* (agreeing currently technology allows only blending up to 20%). Further, blending at 20% decreases a pipeline's time-to-failure number by nearly 60%. CPUC Study, *supra*, at 59. And really, we just don't know what happens for sure at these higher levels of blending other than that the results are not good. Beyond 2%, we have some knowledge gaps; beyond 10%, the knowledge gap extends to "network management & compression"; at 30%, our knowledge is limited to "distribution, safety, and end-use equipment"; and at 50%, we have basically nothing. *Id.* at 107-08. Where is there broad agreement? That blending at anything like the percentages EPA proposes here is not feasible. *See*, *e.g.*, Zahreddine Hafsi, et al., *Hydrogen embrittlement of steel pipelines during transients*, 13 PROCEDIA STRUCTURAL INTEGRITY 210 (2018) (explaining many reasons that "using pipelines designed for natural gas conduction to transport hydrogen is a risky choice").

In partial recognition of these concerns, the Proposed Rule admits that it would require the wholesale "deployment of new pipeline infrastructure designed for compatibility with hydrogen." 88 Fed. Reg. at 33,314. EPA seems to be setting aside the massive industry and political will that will be needed to get anything like that massive construction effort off the ground and to the finish line in time to meet the Proposed Rule's timelines. EPA seems to be setting aside, too, the litigation roadblocks that tie up existing pipeline projects for years—Congress just passed Section 324 of the Fiscal Responsibility Act to try to get the Mountain Valley Pipeline out of a years-long litigation purgatory, after all. Even so, the costs to build almost wholly "new" "infrastructure" would be astronomical. The Congressional Research Service estimated that even 66,000 miles of CO2 pipeline would cost $170 billion. CARBON DIOXIDE PIPELINES: SAFETY ISSUES, *supra*, at 1. So yet again, the Proposed Rule sits at a crossroads of "exorbitantly costly," *Essex*, 486 F.2d at 433, and downright impossible, *Portland Cement*, 486 F.2d at 402. This situation is "crystal ball inquiry," *Essex*, 486 F.2d at 434, into "purely theoretical or experimental" technologies, *Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 786, at its finest.

4. The cost of co-firing hydrogen is exorbitant.

In large part from logistical challenges like this, co-firing with hydrogen is prohibitively expensive. Even DOE recognizes that "[t]he levelized cost of hydrogen must be reduced significantly" before it can be widely deployed. HYDROGEN STRATEGY AND ROADMAP, *supra*, at 24. "Across applications, costs need to fall significantly compared to their current level to become competitive from a sustainable, market-driven perspective." *Id.* at 25. Hydrogen fuel is not remotely financially competitive with natural gas—it currently costs several times as much. In fact, just buying normal hydrogen costs anywhere from three to six times more than natural gas based on the type of turbine and the cost of hydrogen. HYDROGEN COUNCIL, PATH TO HYDROGEN COMPETITIVENESS—A COST PERSPECTIVE 59 (2020), https://tinyurl.com/yvpddeax.

The price difference is, in part, because of the difficulty and cost of manufacturing hydrogen—and that problem only gets worse if EPA requires combustion turbines to burn less-common ultra-low-greenhouse gas hydrogen. Some of the issues that will inflate ultra-low-greenhouse gas hydrogen's cost include no "distribution infrastructure" and a "lack of manufacturing at scale," as well as "cost, durability, reliability, and availability challenges in the supply base across the entire value chain." HYDROGEN STRATEGY AND ROADMAP, *supra*, at 24. Systemic uncertainty in the hydrogen market has also made stakeholders at every point in the supply chain hesitant to "sign long-term contracts," which in turn inhibits industry growth and increases costs. *Id.* "Storing hydrogen efficiently and safely is also a considerable challenge." *Id.* at 25. As EPA admits, the "adequacy and availability of hydrogen storage facilities" "present obstacles" to using low-greenhouse gas hydrogen long term. 88 Fed. Reg. at 33,308.

The Proposed Rule doesn't take these costs seriously enough for a statute that requires EPA to consider "cost of achieving" emission reductions when determining whether a given technology is "adequately demonstrated." 42 U.S.C. § 7411(a)(1). It says that we should ignore current realities because soon ultra-low-greenhouse gas hydrogen will be "competitive with" the hydrogen that's manufactured. 88 Fed. Reg. at 33,310. But this estimate works only because EPA assumes that every variable will break in its favor—that R&D hits no snags, that federal subsidies work as expected, and on and on. *Id.* at 33, 310. EPA calls this the "more optimistic" outcome. *Id.* Really, it's an unsupported assumption that all the stars will align perfectly. That makes its cost estimates risibly low. For example, the Proposed Rule says the levelized cost of energy increase for combined cycle units will be about "$1.4/MWh and $11/MWh for the 30 percent and 96 percent (by volume) cases, respectively." *Id.* at 33,314. And capital costs will be only 5% higher and non-fuel variable costs will be only 10% higher. *Id.* at 33,313.

These numbers *might* not rise to statute-defying heights if they prove accurate. But that's a big "if." The numbers rely on $9.5 billion investment in hydrogen co-firing—and apart from the general weakness from investment-based-predictions discussed above, the Proposed Rule shows that EPA is not confident that these investments will do what it hopes. 88 Fed. Reg. at 33,309 (saying the investments "*could* translate to" lower costs (emphasis added)). It is also impossible to fully scrutinize these predictions for the more basic reason that EPA hasn't put the subsidies together yet. *Id.* at 33,329. And the Proposed Rule has a wholly impractical answer for the sky-high prices to build out the pipeline network we discussed above: Co-firing plants should just be "located close to the source of hydrogen." *Id.* at 33,314. Most natural gas plants are not. Just one currently operating clean hydrogen manufacturer is located between Nevada and Lake Erie—in Minnesota. *See The Hydrogen Map*, PILLSBURY WINTHROP SHAW PITTMAN LLP, https://www.thehydrogenmap.com/ (last accessed Aug. 6, 2023). But most natural gas plants are in that same hydrogen desert. *See Power Plants in the United States*, ENERGY INFO. ADMIN., https://tinyurl.com/4kjfue76 (last accessed Aug. 6, 2023). And this rule is for *existing* sources, 42 U.S.C. § 7411(d), not a guideline for where operators should put new plants.

Remember too that co-firing aims to replace the backbone fuel of our energy portfolio, natural gas, with a new version of an experimental fuel that currently plays the tiniest of roles in our energy sector. Good reasons (apart from the technological limitations and impossibilities discussed above) explain why hydrogen hasn't caught on already: Hydrogen isn't a natural power source because of "thermodynamic inefficiencies," 88 Fed. Reg. at 33,309, and because it has a "lower energy density of hydrogen compared to natural gas," *id.* at 33,307-08. Put simply, it's not energy efficient—that's why the little hydrogen we currently make is rarely used for co-firing. *Id.* at 33,305. So claiming that we can rearrange a core component of our energy portfolio in a handful of years for the same price we have paid for traditional methods (or modest upgrades to them) takes "optimism" to an unfair level. The Proposed Rule's refusal to seriously grapple with and address these incredible costs is fatal for hydrogen co-firing as a BSER. *Essex*, 486 F.2d at 433.

5. Hydrogen co-firing creates bad environmental side effects.

Finally, co-firing hydrogen creates various environmental issues that flunk the statutory factors. 42 U.S.C. § 7411(a)(1). For example, because hydrogen reduces the hydroxl radical, which destroys other gasses like methane, burning hydrogen indirectly leads to increases in those greenhouse gases. 88 Fed. Reg. at 33,306.

But the biggest issue is NOx emissions. Hydrogen hurts the environment by producing significantly more NOx emissions than natural gas. ETN GLOBAL, HYDROGEN GAS TURBINES 9 (2020), https://tinyurl.com/m95fz5hs ("The higher adiabatic flame temperature of H2 will result in higher NOx emissions if no additional measures are undertaken."). When low levels of hydrogen are blended with natural gas, NOx emissions are somewhat controllable. CHRISTOPHER DOUGLAS ET AL., GA. TECH STRATEGIC ENERGY INST., NOX EMISSIONS FROM HYDROGEN-METHANE FUEL BLEND (2022), at Fig. 1, https://tinyurl.com/yc2jf5fm. We do not, however, have the technology to handle the significant increases of NOx at high levels of blending—especially not the near-100% levels the Proposed Rule contemplates. *See* DEP'T OF ENERGY, DOE HYDROGEN PROGRAM PLAN (2020), https://tinyurl.com/48een8sk. Indeed, co-firing with hydrogen can in some conditions cause up to six times the NOx that pure natural gas does. *See* Mehmet Salih Cellek & Ali Pınarbas, *Investigations on Performance and Emission Characteristics of an Industrial Low Swirl Burner While Burning Natural Gas, Methane, Hydrogen-Enriched Natural Gas and Hydrogen as Fuels*, 43 INT'L J. OF HYDROGEN ENERGY 1194 (2018). And just last year, the University of California press published meta-analyses showing that burning just 20% hydrogen would lead to an almost 10% increase in NO_x emissions. Madeleine L. Wright & Alastair C. Lewis, *Emissions of NOx from blending of hydrogen and natural gas in space heating boilers*, 10 ELEM. SCI. ANTH. 1 (2022).

All this means that "[i]t will be particularly a challenge to achieve even stricter NOx-limits foreseen in the future," ETN GLOBAL, *supra*, at 9. EPA must consider these "counter-productive environmental effects." *Portland Cement*, 486 F.2d at 385. Here though, the agency readily acknowledges that NOx could be a serious issue, 88 Fed. Reg. at 33,312, to the point that there might be so much excess NOx that EPA would need to mandate a new selective catalytic reduction and corresponding scrubber technologies later, *id.* at 33,302. What it doesn't do it propose a BSER that would avoid these issues on the front end—and thus show how *this* rule avoids the "counter-productive" trap. So either EPA does not truly think that sources will adopt this BSER (feeding into the concerns discussed above that the BSER is largely pretextual), or else it has failed to "consider" adequately the statutorily required factors. 42 U.S.C. § 7411(a)(1).

Further hydrogen co-firing will use a lot more water than current technologies—as EPA calculates it, nearly 50% (about 100 gallons) more water per MWh. 88 Fed. Reg. at 33,302. "Just as an example, to run a 60-MW gas turbine on 100% hydrogen and achieve 25 parts per million NOx, you will consume 20 tonnes—or 20,000 liters—of water every hour." Sonal Patel, *Siemens' Roadmap to 100% Hydrogen Gas Turbines*, POWER (July 1, 2020), https://tinyurl.com/bdzzwvuk; *see also* 88 Fed. Reg. at 33,312 n.444 (relying on same article). And the manufacturing part of the process is water-intensive, too: The ratio is 9 to 1 purified water to hydrogen for electrolysis, so co-firing with hydrogen at the proposal's levels would create "water requirements" even "greater" than those for a CCS source. 88 Fed. Reg. at 33,307 n.401. EPA tries to duck this issue by saying "many" new combustion turbines use a dry cooling method, so the additional cooling water requirements are reasonable. But EPA never puts numbers on these assumptions or explains why assumptions for a new-source BSER should translate to an existing-source BSER like this one. More important, EPA elsewhere treats water consumption as a critical factor in its BSER analysis. *Id.* at 33,323 (saying a certain technology has "lower water requirements and therefore could be the preferred technology in arid regions or in areas where water requirements could have significant ecological impacts"). The agency cannot consider other environmental effects when it helps it get to a preferred result and ignore them when the point the other way.

***

Co-firing is either technologically and logistically impossible or just exorbitantly and prohibitively costly. Probably the former—but either way it fails Section 111's rubric. Combined with co-firing's significant negative health and environmental effects, and there's no question that co-firing hydrogen is not an adequately demonstrated BSER.

C. Potential federal subsidies cannot fix this otherwise inadequately demonstrated BSER.

Federal subsidies cannot make up the difference between speculative and demonstrated for either CCS or hydrogen co-firing.

The Proposed Rule is peppered with references to Inflation Reduction Act and Infrastructure Investment and Jobs Act money. *E.g.*, 88 Fed. Reg. at 33,246 (using assumptions about IRA money to build the proposal's cost "model[s]"). Both proposed BSER technologies are enormously costly, as explained above. And both hamstring traditional ways utilities raise capital—for example, many power plants make and pay for improvements using unit-operating revenue as collateral. Am. Pub. Power Ass'n, Comment Letter on EPA's Federalism Consultation on Clean Air Act Section 111(d), 111(b), and MATS RTR Rulemakings 4 (Nov. 21, 2022), https://tinyurl.com/vtzspajf. But CCS and co-firing decrease future output, which in turn reduces owners' ability to make improvements through this financing method. This is especially true for single units and smaller systems. 88 Fed. Reg. at 33,302 (noting that units should accommodate less output by simply "scaling larger"). So EPA is forced to admit that the only way this Proposed Rule might work is if federal subsidies are as effective as EPA hopes they will be. *See*, *e.g.*, *id.* at 33,299, 33,300, 33,307. To be sure, both laws do promise sizable subsidies: The IIJA includes billions in proposed infrastructure spending. *Id.* at 33,260-61. And the IRA provides credits of \$85 for each metric ton of CO_2 stored in secure geologic formations and \$60 for each metric ton of CO_2 used for enhanced oil recovery and injected into secure geologic storage or used in a qualified manner. Pub. L. No. 117-169, § 13104(c), 136 Stat. 1818, 1924-1929 (2020). Even so, these subsidies are not the elixir EPA hopes for.

For one, EPA never explains how it and other federal agencies will use these funds. The IIJA allotted federal agencies around \$9.5 billion to help develop hydrogen options, and \$12 billion for CCS. Press Release, *Fact Sheet: Biden-Harris Administration Advances Cleaner Industrial Sector to Reduce Emissions and Reinvigorate American Manufacturing* (Feb. 15, 2022), https://tinyurl.com/wemvzy6v; *see also* 88 Fed. Reg. at 33,260 (using same amounts). The Proposed Rule does not explain, though, where this money is going and, more important, what it expects it will accomplish practically—or how fast. Listing spending categories is as deep as it goes. *Id*. Nor do its sources clarify the picture any. For example, EPA says the hydrogen production tax credit "is expected to incentivize" growth of low-greenhouse gas hydrogen, *id.* at 33,261, but its one supporting citation recites IRA changes to the tax credit and summarily concludes that "clean hydrogen will be primed for takeoff through the 2020s," J. LARSEN ET AL., RHODIUM GRP., A TURNING POINT FOR US CLIMATE PROGRESS: ASSESSING THE CLIMATE AND CLEAN ENERGY PROVISIONS IN THE INFLATION REDUCTION ACT 9 (2022), https://bit.ly/45jazn4/.

The issue is that throwing money at problems of time and technological barriers is no solution to the "adequately demonstrated" problem. Consider an analogy to medical research. Like the energy sector with CCS, medical researchers have been studying cures to various diseases for decades. Money may be one limit in those endeavors, but it is not the only one. Suppose that HHS issued a rule compelling hospitals to offer "Alzheimer's-curing" treatments by 2035. The hospitals would likely object because those treatments don't yet exist—but then HHS points to a half trillion dollars in a recent spending bill allocated to Alzheimer's research as proof that the cure will be discovered, tested, and developed by the compliance deadline. Especially with no sense what research or trials this money would fund or what commercial development would look like, the money is no answer to HHS's impossible mandate. After all, this isn't a situation where the cure is in a laboratory somewhere and government dollars can help get it mass produced and into pharmacies. So it would be unreasonable for the agency to require a treatment that may or may not come to fruition, even with strong motivation and funded research conditions to help things along. So too here. Pointing to even huge figures in federal subsidies cannot give reasonable assurance that the market will find solutions (and develop and bring them to scale in time) for the many practical hurdles that face CCS and hydrogen co-firing.

Especially because history gives us plenty of reasons to suspect that subsidies will not work as EPA hopes. The federal government got into the CCS game back in the early 2000s and spent $1 billion on a carbon capture project at a coal plant. But by 2008 DOE had to split the project into three smaller demonstration projects because of "new market realities." CONG. RESCH. SERV., RL33801, CARBON CAPTURE AND SEQUESTRATION (CCS) 27 (2008), https://bit.ly/43SofEg. The American Recovery and Reinvestment Act of 2009 dropped another $3.4 billion into CCS research, but that was a bust, too: out of nine large-scale projects that money funded (including five commercial power plant projects), only two remain operational—and neither is a power plant. U.S. GOV'T ACCOUNTABILITY OFF., GAO-18-619, ADVANCED FOSSIL ENERGY INFORMATION ON DOE-PROVIDED FUNDING FOR RESEARCH AND DEVELOPMENT PROJECTS STARTED FROM FISCAL YEARS 2010 THROUGH 2017 (2018), https://bit.ly/3Oqa6sd; U.S. CONG. BUDGET OFF., FEDERAL EFFORTS TO REDUCE THE COST OF CAPTURING AND STORING CARBON DIOXIDE 4 (June 2012), https://bit.ly/3DNQNUV. Just two years ago, in fact, the GAO released a report criticizing DOE's administration of that program: DOE had given almost "$684 million to eight coal projects, resulting in one operational facility." U.S. GOV'T ACCOUNTABILITY OFF., GAO-22-105111, CARBON CAPTURE AND STORAGE: ACTIONS NEEDED TO IMPROVE DOE MANAGEMENT OF DEMONSTRATION PROJECTS (2021), https://tinyurl.com/3wpp6736 ("GAO Report"). These CCS projects were "high-risk," GAO said—chiefly because DOE rushed the process. *Id.* DOE also "expedited time frames," bypassing cost controls and spending far more on projects than intended, and kept supporting projects that failed to hit key milestones. *Id.* With compliance deadlines only a handful of years away if EPA finalizes this proposal, we can expect similarly rushed conditions here. And congressional oversight is key to avoiding CCS projects that have "little likelihood of success," *id.*, but it's unclear how much and what kind of oversight will come with the federal dollars EPA clings to. Nor does the Proposed Rule point to any other features of this round of subsidies that suggest it will be more effective than the first billion DOE mismanaged.

Instead, CCS may likely remain—despite extravagant financial support—one of those technologies that stays "one decade away" from being ready. Alfonso Martínez Arranz, *Hype among low-carbon technologies: Carbon capture and storage in comparison*, 41 GLOBAL ENVIRONMENTAL CHANGE 124, 130 (2016). As GAO put it, many of DOE's chosen projects were abandoned because of various "factors affecting their economic viability"—even with hundreds of millions of federal dollars propping them up. GAO Report, *supra*, at 11.

Further, 45Q tax credits are difficult to get. EPA seems to presume an essentially 100% take rate, 88 Fed. Reg. at 33,261 (including IRA credits in cost analysis because the agency was "assuming" various requirements would be "met"). But not all regulated parties will be able to jump through each statutory and regulatory hoop. To get 45Q money, applicants must begin constructing CCS by 2033, after which they have 12 years to collect their tax credits. 26 U.S.C. § 45; *see also Instructions for Form 8933*, I.R.S. (Dec. 2022), *available at* https://bit.ly/3qjp5My. Applicants must meet capacity requirements (produce 18,750 tons annually and capture at least 75% of the CO_2 emitted), and they must pay prevailing wages and limit the number of hours that apprentices work at their facilities. 87 Fed. Reg. 73,580 (Nov. 30, 2022). And for applicants that choose to tie beginning construction to spending 5% of the total costs for the project, 87 Fed. Reg. at 73,582, they must be mindful that overrun project costs do not mean that initial spend slips under 5%—in that case, they do not qualify for the credit. I.R.S. Notice 2018-59, 2018-28 I.R.B. 196, *available at* https://bit.ly/3Qts13P.

A "continuous program of construction involves continuing physical work of a significant nature" must persist through all of this—no voluntary gaps allowed. I.R.S. Notice 2018-59, *supra* § 6. If applicants are updating old facilities rather than building new—like the applicants who would be seeking the credit in connection with trying to satisfy *this* rule—they get the 45Q credits only if the new components used in the update cost at least four times the value of the used components. 86 Fed. Reg. 4,728, 4,736 (Jan. 15, 2021). Facilities also have myriad miscellaneous rules, like penalties for funding CCS construction with tax-exempt bonds. *I.R.S. Instructions for Form 8933*, *supra*. And the I.R.S. is still working out much of its 45Q regulations. 86 Fed. Reg. at 4,753 ("Section 45Q requires regulations for determining adequate security measures for the secure geological storage of qualified carbon dioxide … standards for recapture of section 45Q credits, standards for determining what is a qualified facility for purposes of meeting certain minimum carbon capture thresholds, and standards for carbon dioxide utilization.").

These conditions are likely part of the reason that even though 45Q credits have been around since 2008, we still have only a few CCS facilities—and zero in commercial-scale facilities in the energy sector. Market forces can easily destroy 45Q plans, too. *See* Wamsted & Schlisse, *supra* (discussing this phenomenon in Petra Nova context). Indeed, EPA never discusses or analyzes how many entities already get 45Q credits, how many have applied before or will likely apply, or what applicants' success rate might be. So little surprise to find a wide divergence of predictions by federal entities about how successful 45Q credits will be—nor that EPA is more bullish than the others. The Joint Committee on Taxation estimates that 45Q credits will lead to only 20 million metric tons of carbon captured between 2018 and 2027 yet cost about $700 million. *See* FWW Report, *supra*, at 3. The Congressional Budget Office estimates anywhere from 9 to 13 million metric tons captured a year for ten years after the IRA, with a $3.2 billion price tag. *Id.* Yet EPA estimates over 40 million metric tons on average from 2028 to 2042, cost unknown. 88 Fed. Reg. at 33,409.

What's more, the Proposed Rule does not account for the potential that this money—or at least a large part of it—could go away if political winds or agency leadership shift. This is a politically fragile budget item, and it's foolhardy to shore up significant holes in the agency's BSER analysis with it.

Of course, all this is not to say that federal money cannot play any role in the analysis. Theoretically, federal subsidies could help establish a technology that *later* forms a BSER. But that's the key: EPA is going in the wrong order. It cannot pick a currently speculative technology and trust federal dollars to take it from imaginary to adequately demonstrated. Federal credits and subsidies are not a Section 111 cheat code to skip the statute's requirements. EPA chose to use emerging technologies as BSERs, so it will have to stand them up against the "demanding" standard to justify each of its predictions. *Sierra Club*, 657 F.2d at 348. Imprecise guesses about what a lot of money can do quickly doesn't make things any more concrete.

IV. The Proposed Rule Is Arbitrary And Capricious.

Even if EPA had statutory authority to move forward with the Proposed Rule, other principles of reasoned rulemaking would still stand in the way. A reviewing court may hold a rule unlawful or set it aside under the Administrative Procedure Act if it is arbitrary and capricious. 5 U.S.C. § 706(2)(A). And "[a]rbitrary and capricious simply means unreasonable." *Sithe/Indep. Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 n.2 (D.C. Cir. 2002). Finalizing this proposal would be unreasonable for several reasons. The significant technological hurdles and unbalanced cost-benefit analyses discussed above all apply here, too—Congress made doubly sure EPA would have to consider factors like these by writing them into the primary statutory text, but they also render the proposal arbitrary and capricious. We end this comment by emphasizing three additional concerns to add to that mix. First, this proposal would devastate grid reliability even as our electricity demands and vulnerabilities increase. Second, it undermines EPA's commitment to environmental justice and vulnerable communities rather than advancing it. And third, it turns on unreasonable predictions about market developments. "An agency engaged in reasoned decisionmaking may not ignore 'an important aspect of the problem.'" 88 Fed. Reg. at 33,316 (quoting *Motor Vehicles Mfrs. Ass'n v. State Farm Auto Ins.,* 463 U.S. 29, 43 (1983)). So for these reasons too, we urge EPA to reconsider.

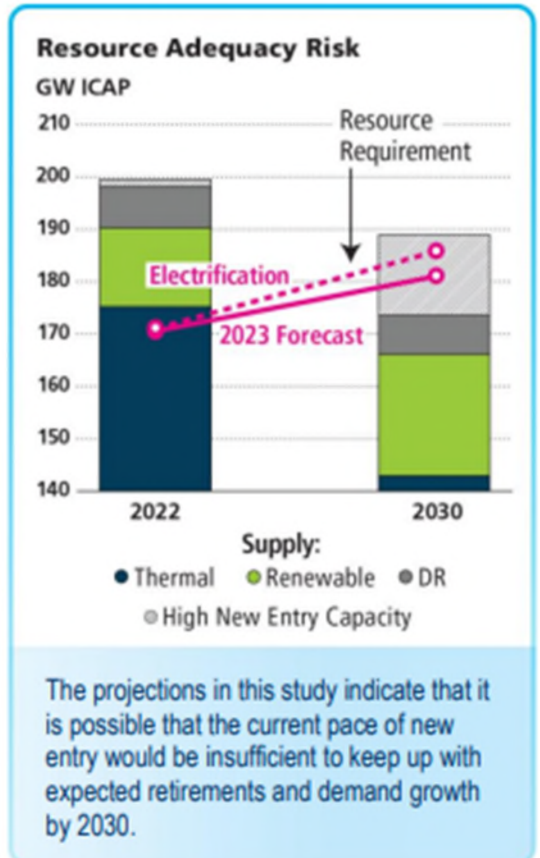
A. The Proposed Rule Would Devastate Long-Term Grid Reliability.

The Proposed Rule is more than a thumb on the scale for a too-quick transition to a renewables-centered market—as explained above, it *forces* the electricity-generating market to make that leap. Moving at the pace EPA wants to require is a recipe for grid failure.

Nobody disputes that grid reliability is crucial—not even EPA. *See*, *e.g.*, 88 Fed. Reg. at 33,243. But the confluence of at least three factors shows that grid reliability is especially fragile right now—and the Proposed Rule will exacerbate that problem. First, demand for electricity will continue increasing in the next few decades. Besides normal population growth, behind-the-scenes components of our increasingly electrified society, like data centers or crypto-currency mining, rely on the electricity grids in ever-increasing measure. And this is hardly EPA's only venture that will tap an already-strained system: Perhaps most obviously, EPA is also looking to replace internal-combustion-engine vehicles with electric vehicles. All of these factors will combine to increase electricity demand by almost 40% by 2035. Katie Brigham, *Why the electric vehicle boom could put a major strain on the U.S. power grid*, CNBC (July 7, 2023, 11:43 a.m.), https://tinyurl.com/4vrynmu7 (noting that California alone will have to spend $50 billion to keep their grid reliable).

Second, according to the EPA, as climate change worsens extreme weather events will become more common. 88 Fed. Reg. at 33,249. "[C]hanges in the frequency and intensity of heat waves, precipitation, and extreme weather events; rising seas; and retreating snow and ice," *id.*, would also stress the grids more than average.

And third, federal and state policies are already pushing a significant number of fossil-fuel plants into retirement over the next 15 years—mostly coal-fired units. For example, the recent effluent limitations guidelines rule, which would limit wastewater discharges from power plants, is expected to cause nearly 10,000 MW of retirements by the year 2028 alone. *Today in Energy*, ENERGY INFO. ADMIN. (Nov. 7, 2022), https://tinyurl.com/598952xm. We're already at a place where "[r]etirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chains, whose long-term impacts are not fully known." PJM, ENERGY TRANSITION IN PJM: RESOURCE RETIREMENTS, REPLACEMENTS & RISKS 1 (2023), https://tinyurl.com/4sa3ez9z.[2] PJM's analysis of its portfolio "shows that 40 GW of existing generation are at risk of retirement by 2030, including 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements." *Id.* at 2. All this is, together, a fifth of PJM's capacity. *Id.* And most of these "thermal" resource retirements are coal plants. The graphic to the right shows how these retirements will put the PJM in real jeopardy. *Id.*



These retirements would come at a time when grids around the country are already straining due to population and economic growth and increased electrification. Take South Carolina for example. Several times this past winter, South Carolina's cooperatives nearly had to cut power to members on several extremely cold days around Christmas. And some South Carolina utilities had to do just that—cutting power to industrial and residential customers. Similar lack of generation capacity caused problems in many other States this last winter as well. *See, e.g.*, Robert Zullo, *Another winter storm strained the electric grid; experts say it's time to fix transmission lines*, IND. CAP. CHRON. (Jan. 3, 2023, 6:00 a.m.), https://tinyurl.com/4mjstvuj.

Fossil fuels are crucial to maintaining grid reliability. As PJM's graphic shows, over the next ten years renewables will begin to dominate our regional transmission organizations' balance sheets—especially if the Proposed Rule moves ahead. But renewables are a nightmare for grid reliability because they're inconsistent: Where can consumers turn when the sun isn't shining and the wind isn't blowing? The answer is coal and natural gas turbines. They are efficient, and many natural gas units have short ramp up times, meaning they can be started and stopped more easily

[2] PJM is the regional transmission operator in charge of electricity transmission in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

than other sources. At this point and into the foreseeable future, renewables *need* natural gas to be successful. N.Y. IND. SYS. OPERATOR INC., NAESB GAS ELECTRIC HARMONIZATION FORUM SURVEY COMMENTS (2021), https://bit.ly/3QxsBxw ("With the increasing number of intermittent electricity resources being installed and increasing variability in electric load, natural gas-fired power plants will be called on to utilize their fast start and quick ramping capability to respond and serve as a backstop to maintain the reliability of the power grid."). That's why since 2015 most simple cycle turbines have been built in Texas, California, and Oklahoma—because those areas have high penetration of renewables. Pretty much everyone agrees natural gas will be important no matter when and how fast we transition to more renewables. *See* ELECTR. POWER RSCH. INST., STRATEGIES AND ACTIONS FOR ACHIEVING A 50% REDUCTION IN U.S. GREENHOUSE GAS EMISSIONS BY 2030 (2021), https://tinyurl.com/2wzjfkvy; CONSUMERS ENERGY, 2021 CLEAN ENERGY PLAN 8 (2021), https://tinyurl.com/mvbw556f. Indeed, California's infamous brownouts are a cautionary tale of what happens when a grid actively tries to eradicate natural gas as a supplement or backstop energy source. *See* Sammy Roth, *California declared war on natural gas. Now the fight is going national*, L.A. TIMES (Feb. 9, 2023, 6:00 a.m.), https://tinyurl.com/47kv7amc. Any reasonable federal policy "must reflect this reality" that "[n]atural gas is the reliability fuel that keeps the lights on." N. AM. ELECTR. RELIABILITY CORP., 2021 LONG-TERM RELIABILITY ASSESSMENT (2021), https://bit.ly/3DM9SqE.

Coal also plays an important grid-reliability role—especially in cases of extreme weather when natural gas can be hard to transport. For example, during the Bomb Cyclone in January 2018, 42% of the PJM region's electricity was generated through coal because natural gas supply problems were driving unusually high outages. Paul Bailey, *Am. Coalition for Clean Coal Elec., MISO, PJM and the Bomb Cyclone: Two Case Studies for Why We Need a Coal Fleet*, AMERICA'S POWER (Feb. 14, 2018), https://bit.ly/43WJ55y (last accessed Aug. 7, 2023). Coal's dependability makes it unreasonable to count it out as a significant portion of our energy portfolio. So in targeting coal and natural gas for elimination at rates the grids cannot sustain, the Proposed Rule is pushing our energy stability off a cliff and snatching away its parachute.

And consider the combined effect of all the anti-fossil-fuel actions EPA has taken over the past few years and plans to take soon: effluent limitations guidelines, coal combustion residuals, NAAQS for particulate matter, a federal implementation plan for ozone, vehicle-fleet electrification, and more. The cumulative effect of these and other anti-fossil-fuel actions devastates grid reliability. The less diverse market-driving mandates like these make our energy portfolio, the more vulnerable we are to unexpected *and* predictable energy needs. Our residents need electricity to survive extreme weather, for instance, and that's precisely when a fossil-fuel-free grid will be the weakest and most vulnerable. *See* OFF. OF ENERGY, POL'Y AND INNOVATION & OFF. OF ELECTR. RELIABILITY, FERC, WINTER ENERGY MARKET AND RELIABILITY ASSESSMENT 2022-2023 18 (2022), https://bit.ly/44YCZmi ("[A]lthough all regions are expected to maintain adequate reserve margins through the winter, reserve margins do not guarantee reliable operations, especially during winter."). This is all exacerbated because both BSERs in the Proposed Rule target the highest-producing fossil-fuel plants—the workhorses of the grid. *See*, *e.g.*, 88 Fed. Reg. at 33,302 (noting that net power output is projected to fall by over 10% with co-firing).

The Proposed Rule also all-but promise to decimate grid reliability through not only its BSERs, but also through its subcategorization scheme. Under previous Section 111 regulations, EPA regulated based on two categories of plants: baseload and peaking. Now EPA wants to create an "intermediate" category that applies to combustion turbine units running around 20-50% of capacity. 88 Fed. Reg. at 33,322. And sources in this intermediate category will have to co-fire 30% hydrogen by 2032. *Id.* This framework will likely put many utilities in a bind.

Consider this example: Remember that new simple cycle natural gas combustion turbines are used mainly to supplement renewables. *See* 88 Fed. Reg. at 33,278. Let's say a utility gets a simple cycle turbine to use as a peaking resource—around 10-15%. But now suppose that for whatever reason the renewables in its portfolio don't perform as planned. In a normal situation, the utility would provide consistent and reliable generation and distribution by pushing the turbine up to and over the peaking line into the intermediate category. But under the Proposed Rule's regime, slipping over that line would trigger the Proposed Rule's 30% co-firing requirement—putting them in an impossible spot technologically and financially. A utility in that position would struggle during unexpectedly low-supply or high-demand situations—especially smaller utilities supported by a single plant. But on the other side of the calculus are state regulations that require utilities to provide electricity consistently, and regional transmission organizations have similar load and adequacy requirements for their load-responsible entities. *See*, *e.g.*, David Eggert, *Will new rules for Michigan utilities force a solution?*, CRAIN'S DETROIT BUS. (May 30, 2023, 10:00 a.m.), https://tinyurl.com/4chzvv7m (noting that for the first time in 20 years Michigan's Public Service Commission "lowered the threshold for what is considered unacceptable performance during outages, and boosted bill credits for customers who go without electricity and made them automatic"); Southwest Power Pool, Inc., *Load Responsible Entity for Reserve Margin Obligation* (June 2015), https://tinyurl.com/5b8ad7a9 (a regional transmission organization explaining some of its requirements for participating power plants).

In short, utilities in high-demand or other stressed states face a no-win scenario. And EPA's own numbers show that this scenario is not hypothetical. "Between 2015 and 2021," it says of the on-average 16 simple cycle turbines that came online every year, "an average of six operated" above 20% capacity factor "and thus would be considered intermediate load combustion turbines." 88 Fed. Reg. at 33,288. The number of simple cycle turbines pushed up to and past that 20% barrier will only increase as more renewables come online and simple cycle turbines must pick up the slack.

Further, gutting grid reliability would have damaging secondary effects. Electricity is a crucial ingredient in economic development—everything from factories to office buildings to universities need it. That's why power availability and energy rates are often a key factor in major construction efforts. For example, when Ford Motor Company set out to open a massive new facility a few years ago to build F-Series pickups and electric vehicles, it chose Tennessee over Michigan—in part because Michigan lacked reliable, cheap energy. *See* Taylor DesOrmeau, *Ford didn't give Michigan shot at new electric plants, Whitmer says*, MLIVE (Sept. 29, 2021, 4:49 p.m.), https://tinyurl.com/yc25wvw7. Businesses seek predictability before major investments—especially about key fixed costs like energy inputs. So grid reliability is a non-negotiable part of a thriving economy—making this proposal even more suspect.

The Proposed Rule does not adequately account for any of this. Indeed, EPA underestimates how important combined cycle baseload units will be for grid reliability going forward. In trying to minimize the effects of the Proposed Rule, EPA notes that new combined cycle baseload builds (against which the CCS and co-firing BSERs would chiefly be applied) represent only "14 percent of all new generating capacity built in the US." 88 Fed. Reg. at 33,303. So, the implication goes, even if these BSERs shut things down, it's only 14%. *Id.* But this analysis confuses generation *capacity* with actual *generation*. Remember that combined cycle baseload units are the workhorses of the EGU world; they run at least 50% of the time, and usually much more than that. Simple cycle units, on the other hand, usually run at around 10-15% of their capacity. So a power plant could install three to five simple cycle units and would likely generate the same power as one combined cycle unit—despite having several times the generation capacity. That's why actual generation is the proper unit to evaluate the proposal's effects on the energy sector. And there's no question that this rule would target most harshly the units that do the most generating.

B. The Proposed Rule Sets Back Environmental Justice.

EPA defines "environmental justice" as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies." *Environmental Justice*, EPA, https://tinyurl.com/2nzfw93r (last accessed Aug. 6, 2023). President Biden's Administration has emphasized as environmental justice as one of its key priorities. *See* Exec. Order No. 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All, 88 Fed. Reg. 25,251 (April 26, 2023), https://bit.ly/3Ys5mXQ. Among other things, it has promised to "build upon and strengthen its commitment to deliver environmental justice to all communities across America." *Id.*

Even so, this proposal wouldn't help the groups it aims to, and it would hurt others, like the rural poor. For one thing, raising energy costs are always a regressive tax. *See Low-Income Community Energy Solutions*, DEP'T OF ENERGY, https://bit.ly/44YqhUA (last accessed Aug. 6, 2023) (noting that lower income households pay nearly three times as much of their income towards electricity costs, 8.6%, compared to high income households' 3%). And given CCS's and hydrogen co-firing's exorbitant costs, this would be an especially steep regressive tax.

For another, the fossil-fuel industry supports millions of blue-collar jobs—at coal mines in Kentucky and West Virginia, to natural gas fields in Texas and Louisiana, to oil fields in North Dakota and Alaska. These workers' families suffer when policies like this "turn the screws on fossil fuels." *The US EPA's proposed regulation could help to kill off fossil-fuel plants. Good on it*, NATURE (June 13, 2023), https://tinyurl.com/bddt68yx (editorial, praising the Proposed Rule for "help[ing] to kill off fossil-fuel plants" because "[e]xpanding clean energy isn't enough to combat the climate crisis"). As we already noted, even the EPA (under)estimates this job loss at 25,000 recurring job-years, *see* REGULATORY IMPACT ANALYSIS, *supra*, at 5-17, while other commenters put total direct job loss close to 275,000 and indirect job loss over 1 million, *see* Int'l Bhd. of Boilermakers, *supra*, at 14-15. Moving to the city, CCS systems' massive footprint functionally doubles the amount of already too-limited urban space utilities would need. And as even EPA admits, bringing hydrogen into and burning it in densely populated areas could be problematic because we have no idea how the technology would interact with urban environments. 88 Fed. Reg. at 33,286. As already explained, though, we do know that the increased NOx emissions will hurt these urban communities.

Further, despite EPA's claims to have "carefully considered" environmental justice concerns, it must admit that representative groups still strongly oppose CCS on environmental justice grounds. 88 Fed. Reg. at 33,247. Private interest groups who strongly agree with EPA's anti-fossil fuels mission have long been skeptical of CCS for many reasons we have raised, among others. *See*, *e.g.*, Env't Def. Fund, Comment Letter on Carbon Capture, Utilization, and Sequestration Guidance – Docket No. CEQ-2022-0001 (Apr. 13, 2022), https://tinyurl.com/8n4sjxs5 (noting "valid" and "nontrivial" "environmental justice and equity challenges posed by even responsible [CCS] deployment"); Press Release by Climate Justice Alliance, *Climate Justice Alliance Warns Carbon Capture & Sequestration, Hydrogen Would Harm Frontline Communities & Perpetuate Climate Crisis Despite Ambitious 90% Cuts to Power Plant Carbon Emissions* (May 11, 2023), https://tinyurl.com/mr4c4292 ("It is shameful that … the EPA is mandating policies … at the expense of Black, Brown, and Indigenous communities. Carbon capture technology and hydrogen will increase local air pollution, taint clean drinking water … and raise energy bills for families nationwide."). Even this White House's Environmental Justice Advisory Council listed CCS as two example of climate change solutions that "will *not* benefit a community." WHITE HOUSE ENV'T JUST. ADVISORY COUNCIL, FINAL RECOMMENDATIONS: JUSTICE40 CLIMATE AND ECONOMIC JUSTICE SCREENING TOOL & EXECUTIVE ORDER 12898 REVISIONS (2021), https://tinyurl.com/2zzfcctx (cleaned up) (emphasis added).

Especially when added to the many other reasons to proceed with caution here, the costs to both rural and urban lower-income communities make it unreasonable to press ahead with the Proposed Rule.

C. The Proposed Rule Relies On Unreasonable Predictions About Technology 7, 9, 13, or 17 Years From Now.

Both CCS and hydrogen co-firing turn on predictions about the state of technology well over a decade from now (as we already explained, they do not reflect the state of the market *now*, or even soon). But who could honestly pretend to know what technology will look like then? History is filled with examples of unexpected events and disruptive technologies upending shaky predictions like EPA's here. Seventeen years ago, Lehman Brothers had 25,000 employees and the most popular email domain was Yahoo!. From recent consumer technologies like broadband or iPhones or ride share apps, to more behind-the-scenes developments like fuel injection devices or semiconductor chips, the world looks very different five years after each of these innovations than it did five years before them.

The energy space is no different. In 2012, for instance, the International Energy Agency predicted that coal would continue dominating the energy sector "for the foreseeable future" and that commercially viable CCS technology would have to develop within the next decade—which ended a year ago. INT'L ENERGY AGENCY, TECHNOLOGY ROADMAP—HIGH-EFFICIENCY, LOW-

EMISSIONS COAL-FIRED POWER GENERATION (2012), https://tinyurl.com/bd8fydyz. EPA itself noted in the Proposed Rule that the unforeseen fracking explosion in the late 2000s transformed the energy sector. 88 Fed. Reg. at 33,257. So if EPA (or others) had tried to predict in 1998 what America's energy-production sector would have looked like in 2015, it would have been dead wrong. Take combined cycle turbines as another example. EPA admits that in 2015 it assumed that simple cycle turbines would play a "*unique* role" in grid reliability that combined cycle turbines couldn't—that is, as peaking load units. 88 Fed. Reg. at 33,320 (emphasis added). The CPP's BSER reflected that assumption. But because of unforeseen technological advancements—improvements in "ramp rates" and integration with renewable and storage projects—EPA's assumption then was quickly proved wrong, to the point that *this* Proposed Rule suggests a fundamental shift in a new direction. 88 Fed. Reg. at 33,320. EPA has not adequately explained why this time is any different when it comes to predictions, critical to the proposal's success, that speculate years into the future.

Crafting BSERs based on these extended timelines is also unreasonable because it unnecessarily forces companies to make critical decisions with too little information. Deadlines in 2030 are not that far from an industry-planning standpoint. Companies will have to start making critical and long-term investment and operational decisions now in preparation for that date. Everything from permitting to construction an especially long time in the energy sector, and decisions in this space incorporate a staggering number of variables. Josh Saul, Cailey LaPara & Jennifer A. Dlouhy, *Permits for US Energy Projects Are So Bad Unlikely Allies Emerge*, BLOOMBERG (June 7, 2023, 4:00 a.m.), https://tinyurl.com/bdfcvtv9 (saying that among a "thicket of regulations," a permit is the hardest part of installing a new "power line or" "gas pipeline," and the "regulatory gauntlet … can consume more than a decade"). So finalizing the Proposed Rule will force companies to make potentially uneconomic and consumer-unfriendly decisions based on technology and market conditions that may or may not develop as EPA predicts.

Courts have been skeptical of too rosy or unsupported predictions in the Section 111 context before. Recall *Sierra Club*'s footnote 157's concern about treating "innovative" or "emerging" technologies as "adequately demonstrated." 657 F.2d at 341 n.157. As explained already, the BSERs here don't even meet that standard. Of course, EPA can project somewhat into the future—it must. *See Portland Cement*, 486 F.2d at 391; *Lignite*, 198 F.3d at 934. But its projections and predictions must be "fair[]," *Portland Cement*, 486 F.2d at 391—and a technological projection's "fairness" diminishes in proportion to how much is being projected and over how long a timeframe. So if EPA, say, predicts how much of an established scrubber solvent will be available next year, it's likely on safe ground. Predicting how many miles of CO_2 pipeline will be available in 2028 is much more difficult going. And projecting how embryonic, nascent industries like CCS and hydrogen may grow over the next nine-to-twelve years is even more treacherous. As noted above, EPA does not have case law on its side for this agency equivalent of fortune telling. It would have to provide much stronger bases to give a reviewing court confidence in its predictions—and to make the decisions it wants to force on industry prudent.

Perhaps all the current indications that CCS and co-firing are not feasible options will prove wrong with time. But based on the information EPA marshals *now*, it is unreasonable to pin rulemaking of this scope on predictions so little grounded in current realities.

***

It was only a year ago that the Supreme Court reminded EPA that Section 111 has limits. And only a few weeks ago, the Court reaffirmed *West Virginia*'s holding, reiterating that agency programs of "deep economic and political significance" force courts to assess carefully whether Congress departed from the default rule that it intends to keep questions like that "for itself." *Biden v. Nebraska*, 143 S. Ct. 2355, 2375 (2023) (cleaned up). The Proposed Rule falls in that same category. EPA has also chosen BSERs that do not accord with any fair sense of "adequately demonstrated." It has flouted the other statutory factors. And it has signaled that it does not reasonably believe that finalizing the rule will lead to CCS and co-firing on a mass scale. At bottom, the Proposed Rule seems to be another attempt to force fossil-fuel-fired plants to stop producing or else subsidize different forms of generation. But EPA could not reshape what sources are and aren't allowed to comprise the nation's electricity-generating sector through the CPP—and it cannot through this effort, either. For the sake of our residents, businesses, and sovereign interests, we urge EPA to reevaluate the Proposed Rule in keeping with Section 111's limits and the bounds of reasoned rulemaking.

Sincerely,

Patrick Morrisey
West Virginia Attorney General

Steve Marshall
Alabama Attorney General

Tim Griffin
Arkansas Attorney General

Christopher M. Carr
Georgia Attorney General

Raúl Labrador
Idaho Attorney General

Todd Rokita
Indiana Attorney General

Brenna Bird
Iowa Attorney General

Daniel Cameron
Kentucky Attorney General

Jeff Landry
Louisiana Attorney General

Lynn Fitch
Mississippi Attorney General

Andrew Bailey
Missouri Attorney General

Austin Knudsen
Montana Attorney General

Mike Hilgers
Nebraska Attorney General

John Formella
New Hampshire Attorney General

Dave Yost
Ohio Attorney General

Gentner F. Drummond
Oklahoma Attorney General

Alan Wilson
South Carolina Attorney General

Marty Jackley
South Dakota Attorney General

Angela Colmenero
Provisional Attorney General of Texas

Sean D. Reyes
Utah Attorney General

Jason S. Miyares
Virginia Attorey General

Golden Spread
Electric Cooperative, Inc.
A Touchstone Energy™ Cooperative

August 8, 2023

Submitted by Federal eRulemaking Portal:

EPA Docket Center
U.S. Environmental Protection Agency
U. S. EPA Mail Code: 28221T 1200 Pennsylvania Ave. NW Washington, DC 20460
https://www.regulations.gov

Attn: Docket ID No. EPA–HQ–OAR– 2023–0072

Dear Administrator Regan,

Golden Spread Electric Cooperative, Inc. ("Golden Spread") appreciates the opportunity to submit these comments on EPA's Proposed Rule published at 88 Fed. Reg. 33240 (May 23, 2023). Golden Spread also supports and incorporates by reference the comments submitted by the National Rural Electric Cooperative Association ("NRECA"), of which Golden Spread is a member.

I. EXECUTIVE SUMMARY

Key points of Golden Spread's comments include:

- The Proposed Rule would significantly interfere with Golden Spread's mission to reliably provide responsibly generated and reasonably priced electric service to its member distribution cooperatives, which serve consumers largely located in rural areas and who are often affected by poverty. This outcome is not only inconsistent with the nation's climate change policy, but also President Biden's Executive Order 13985, *Advancing Racial Equity and Support for Underserved Communities Through the Federal Government*, which identifies "persons who live in rural communities" and those "otherwise adversely affected by persistent poverty" as deserving of special attention by Federal policymakers.

- The operating ceiling for "low load" natural gas-fired combustion turbines ("CTs") should be set at 33%, retaining the current regulatory ceiling. Mandating a lower ceiling, such as the 20% included in the Proposed Rule, will disrupt the essential role CTs play in supporting the reliable operation and growth of renewables-powered energy sources (e.g., wind and solar). Golden Spread has strategically invested in natural-gas fired "fast start" simple cycle units ("NGSC") to support the abundant and growing wind generation capacity in its service area. A rule aimed at reducing greenhouse gas emissions must not create barriers to the necessary use of NGSC units to support the reliable operation and integration of renewable energy resources.

- Co-firing CTs with hydrogen, or carbon capture and sequestration ("CCS") of greenhouse emissions from CTs, is not the "best system of emission reductions" ("BSER") for CTs on the scale and schedule proposed by EPA. The Proposed Rule also does not adequately consider technical issues such as the impact of hydrogen co-firing on CT reliability, the water intensity of these technologies that limits their applicability in drought-stricken areas such as those served by Golden Spread, and the engineering and energy inefficiencies associated with CCS.

- The proposed allowance for low load CTs to exceed the applicable threshold in the case of "system emergencies" has no value unless generators are not exposed to allegations of violations of other applicable air emission standards (via either regulation or permit).

- EPA has not substantially complied with the public notice and comment provisions of the Administrative Procedure Act ("APA"). EPA has not provided the public with sufficient time to comment on the Proposed Rule, making significant changes to the administrative record during the public comment period without meaningful public disclosure, and suggesting in late-added materials that it might make potentially major changes to requirements in the published Proposed Rule (e.g., changing the applicability of the Proposed Rule from a unit basis to a plant-wide basis, which would have massive economic and technical consequences, an outcome that Golden Spread opposes). Any material change to the Proposed Rule, particularly its applicability provisions, must be accomplished through an amended proposal for public comment that includes a revised technical, economic, and environmental analysis that fully evaluates and justifies the proposed changes.

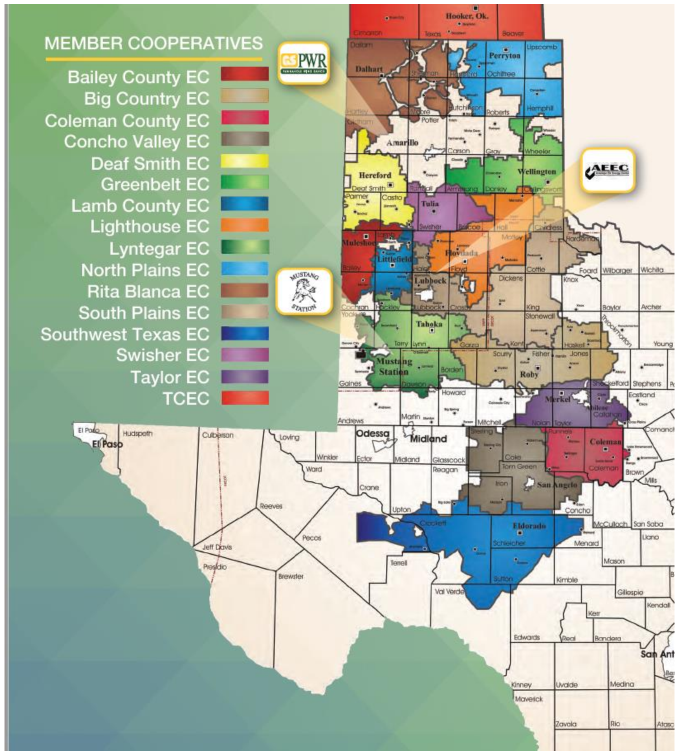
Golden Spread urges EPA to take these comments into account to fashion a final rule that is based on the facts, supports the responsible generation of reliable and affordable energy, and recognizes the critical role of natural gas generated power in ensuring a reliable electric grid with significant renewable energy penetration.

II. GOLDEN SPREAD'S GENERATION RESOURCES ARE USED TO SERVE RURAL COMMUNITIES AND ARE LOCATED IN AREAS WITH SUBSTANTIAL RENEWABLE RESOURCES.

A. Overview of Golden Spread and its Member Cooperatives

Golden Spread is a non-profit electric generation and transmission ("G&T") cooperative headquartered in Amarillo, Texas. Its purpose is to supply reliable wholesale electric power at the lowest feasible cost to its 16 non-profit distribution cooperative members ("Member Cooperatives" or "Members") while abiding by all applicable regulatory requirements. Golden Spread Members provide power to approximately 318,000 retail electric meters serving Member-Consumers (i.e., members of a cooperative and retail electric customers) located over an expansive area, including the South Plains, Edwards Plateau, and Panhandle regions of Texas (covering 24 percent of the state), portions of Southwestern Kansas and Southeastern Colorado, and the Oklahoma Panhandle. Golden Spread owns and operates power plants in both the Electric Reliability Council of Texas ("ERCOT") and the Southwest Power Pool ("SPP"). Figure 1 shows the location of Golden Spread's electric generating units and its Member Cooperatives' service territories.

Figure 1. Golden Spread Electric Generating Units and Members' Service Territories



B. <u>Federal Policy Supporting Electric Cooperatives</u>

Non-profit electric cooperatives such as Golden Spread and its Member Cooperatives are part of the essential infrastructure of rural America. They have played a central role in rural economic development since passage of the Rural Electrification Act ("REA") in 1936 which provided funding for rural electrification. Before the REA, electricity was commonplace in cities but not so in rural areas. Rural America was largely ignored as the focus was on more densely populated areas with higher expected revenues. The REA gave rise to the non-profit, community owned and operated electric cooperative model that is still the backbone of many rural communities today. Now with over 42 million customers nationwide, non-profit electric cooperatives have generated the electricity that has powered the economic development of rural America and supported a way of life and standard of living admired the world over.

The central role of rural America in Federal policy is recently reflected in President Biden's Executive Order ("EO") 13985 of January 20, 2021, *Advancing Racial Equity and Support for Underserved Communities Through the Federal Government*.[1] EO 13895 expressly identifies "persons who live in rural communities" as deserving of specific attention by Federal policymakers to ensure equitable treatment, including specific direction that Federal agencies consult and engage with underserved communities.

[1] 86 Fed. Reg. 7009 (Jan. 25, 2021).

Nationally, cooperatives serve 92% of the nation's persistent poverty counties,[2] and the sparsely populated and primarily residential communities powered by electric cooperatives are often the country's most expensive, hardest-to-serve areas. Of the 79 counties served by Golden Spread Members, 58 are entirely or in part designated as a disadvantaged community.[3]

EPA should heed long-standing policies supporting affordable and reliable rural electrification, as well as EO 13985's directive, and ensure equitable treatment of rural electric cooperatives and the communities they serve in the final rule. The elements of the Proposed Rule that would decrease reliability, curtail the use of renewable energy, significantly increase the use of water, and increase the cost of electricity are inconsistent with EO 13985.

C. Golden Spread Members Serve An Area With High Wind Generation And Increasing Solar Energy Development.

As shown in Figures 1 and 2 below, Golden Spread Members serve a region with high wind and solar energy resources. This region has seen significant growth in renewable development in recent years. In Texas' ERCOT region, 28% of the energy generated in 2021 came from wind and solar (more than twice the national percentage). This penetration increased to 31% in 2022.[4] In SPP, 37.5% of the generation produced in 2022 came from wind.[5]

As a state, Texas leads the nation in wind-powered electricity generation, producing more than one-fourth of the nation's total wind power.[6] Texas generates about 66% more than Oklahoma, the second highest generating state.[7] In the first quarter of 2023, the installed wind capacity in Texas was 40,555 MW, representing 28% of the total installed wind capacity in the country.[8] Texas also has the second largest percentage share of total utility-scale solar electricity generation at 15%.[9]

Wind generation development in Texas and the region is not expected to slow down. Forces driving the growth of wind generation facilities in Texas include favorable wind resources and

---

2 National Rural Electric Cooperative Association. Electric Co-op Facts and Figures. April 13, 2023.

3 U.S. Climate Resilience Toolkit: Climate and Economic Justice Screening Tool. Available at: Climate and Economic Justice Screening Tool | U.S. Climate Resilience Toolkit (https://toolkit.climate.gov/tool/climate-and-economic-justice-screening-tool#:~:text=The%20Climate%20and%20Economic%20Justice,are%20faced%20with%20significant%20burdens.)

4 ERCOT. Fuel Mix Report: 2023. Available at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.ercot.com%2Ffiles%2Fdocs%2F2022%2F02%2F08%2FIntGenbyFuel2022.xlsx&wdOrigin=BROWSELINK.

5 Southwest Power Pool 2022 Annual Report. Available at: https://storymaps.arcgis.com/stories/18725105e46943b5bfe7c77202a4737d

6 DOE's Office of Energy Efficiency & Renewable Energy. U.S Installed and Potential Wind Power Capacity and Generation. Available at *https://windexchange.energy.gov/maps-data/321*

7 *Id.*

8 *Id.*

9 U.S. Energy Information Administration . Solar explained: Where solar is found. Available at*:* *https://www.eia.gov/energyexplained/solar/where-solar-is-found.php*

land availability. Texas has twice the amount of wind power capacity than the state with the second highest wind power capacity potential.[10]

Figure 2. NREL U.S Annual Average Wind Speed at 30 m, February 21, 2012

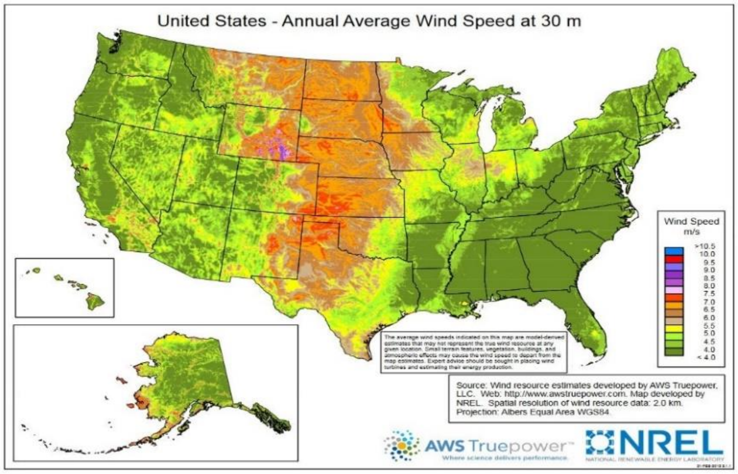
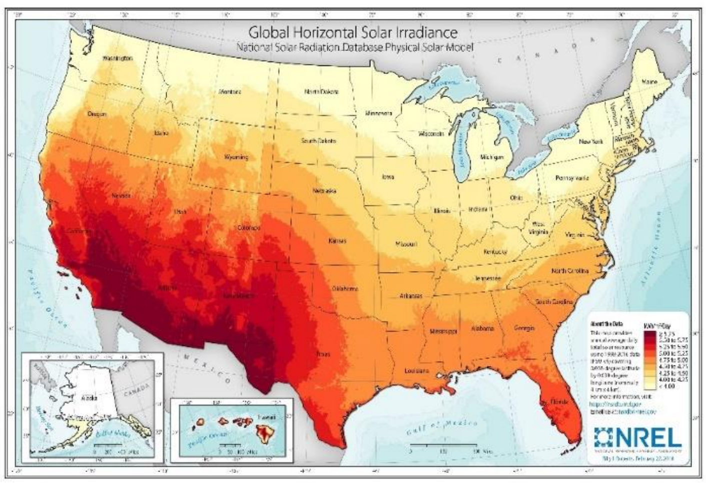


Figure 3. NREL Global Horizontal Solar Irradiance, February 22, 2018



With an expected increase in the reliance on wind energy, the risk of sudden losses of generation necessarily rises with it. Because wind power has a significant role in the region's power generation portfolio, which is anticipated to only increase, alternative generation resources must be in place to maintain grid stability and serve load when weather conditions are not conducive to wind energy production. While steps have been taken to mitigate the risk of intermittent resources like wind, there are startling recent reminders of what can happen when the wind does not behave as one might

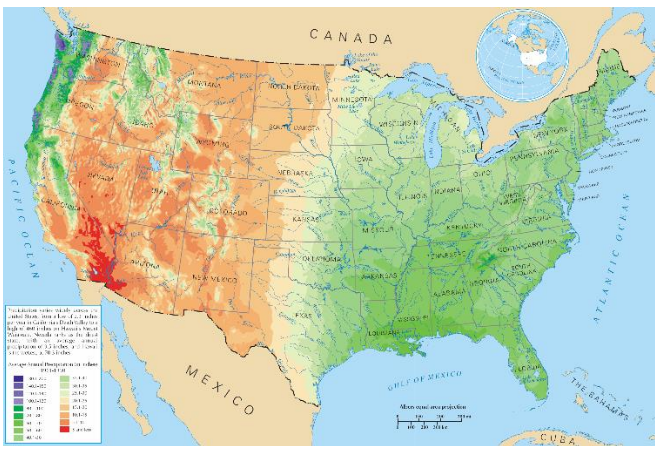
10 Department of Energy. U.S. Installed and Potential Wind Power Capacity and Generation. Available at: https://windexchange.energy.gov/maps-data/321

expect.[11] The risk of sudden losses of generation necessarily rises with the expansion of renewables. Therefore, non-wind energy sources must be available to quickly make up for the loss in wind energy production to maintain the continued viability and growth of renewables and grid reliability. As discussed below, NGSCs play an essential role in reliably integrating renewable generation.

D. Golden Spread Has Limited Water Resources.

While the region in which Golden Spread operates has abundant wind, solar, and land resources, water resources are limited. The region has historically suffered from persistent drought conditions and surface water is scarce due in part to low precipitation as shown in Figure 4. Additionally, the Ogallala Aquifer, which underlies much of the High Plains region where Golden Spread operates, is critical to the economy of the area. For example, approximately 95 percent of the groundwater withdrawn from the Aquifer is used for agricultural irrigation. That, combined with long-term drought conditions, makes the availability of water a critical factor in the design and operation of energy infrastructure in the area. The NGSC units operated by Golden Spread offer significant water efficiency advantages over other resources including natural gas combined-cycle ("NGCC") units. Indeed, one of the reasons CCS and hydrogen co-firing are not technically or economically feasible for Golden Spread is because of water paucity.

Figure 4 Annual Precipitation from 1961 to 1990 by National Atlas of the United States



E. Golden Spread's Electric Generating Resources

Over the past 20 years, Golden Spread has invested more than one billion dollars to build and maintain generation to serve its Member Cooperatives' growing demand and need for electric power supply needs. Due in part to the high wind and solar penetration (and potential for more) in its service area, Golden Spread has pursued a strategy to invest primarily in natural-gas fired "fast start" NGSC as the best resource to support the growing renewable generation and limited water resources in the region.

[11] NERC Quick Reference Guide: Inverter-Based Resource Activities. June 2023. "Panhandle Wind Disturbance" and "2022 Odessa Disturbance." Available at: https://www.nerc.com/pa/Documents/IBR_Quick%20Reference%20Guide.pdf.

Golden Spread's assets include (1) a NGCC unit[12] and three NGSC units[13] located at its Mustang Station in Denver City, Texas; (2) 18 reciprocating internal combustion engines ("RICE") and three fast-starting NGSC units[14] located at its Antelope Elk Energy Center ("AEEC") in Abernathy, Texas; and (3) 34 wind generators located at Golden Spread Panhandle Wind Ranch near Wildorado, Texas. The approximate location of these electric generating units is shown in Figure 1 on page 3 of these Comments. Golden Spread does not own or operate any coal or oil-fired electric generating units. As part of its corporate goal to meet its Members' energy needs, Golden Spread regularly evaluates whether and when it needs to develop new resources.

III. EPA'S PROPOSAL TO DECREASE THE OPERATING THRESHOLD FOR LOW LOAD UNITS FROM 33% TO 20% IS NOT SUPPORTED BY THE ADMINISTRATIVE RECORD AND WOULD ADVERSELY AFFECT THE RELIABILITY OF THE GRID AND INTEGRATION OF RENEWABLE GENERATION.

EPA's proposal to artificially limit low load combustion turbines (i.e., NGSCs) to a 20% capacity factor has no basis in the record and ignores their continuing importance to the reliability and efficiency of the nation's grid, particularly given the increase in renewable energy development. NGSC units play an important and established role in the support of intermittent renewable generation because of their "fast start" and ramping capabilities. That role is anticipated to become more critical as wind generation is increasing at unprecedented levels throughout the country, particularly in wind rich regions like Texas.

Contrary to EPA's analysis in its *Simple Cycle CT Technical Support Document* ("EPA NGSC TSD"),[15] the important role of NGSCs in the integration of renewable generation is not "hypothetical" and "unclear."[16] A potential flaw in EPA's assessment appears in part to be because the EPA NGSC TSD evaluates NGSCs on a generic fleetwide basis and does not accurately consider the significant variability of renewables penetration in different regions. The critical role that NGSCs play in making the growth of renewables possible is not only reflected in Golden Spread's direct experience but has also been widely discussed on a national level.

As recognized by the Energy Information Administration ("EIA")—the agency responsible for providing impartial energy information to promote sound policy making—and is unambiguous about the role played by NGSCs to support renewables:

> "Electric grid operators can use SCGT [simple cycle gas turbine] power plants to respond quickly to fluctuating demand for electricity. The need for more electric grid support during the day is growing as the share of electricity generation from intermittent renewables grows. SCGT power plants can meet demand if there is a lull in wind or solar output. SCGT power plants can best provide grid support because they can produce

[12] 463 MW unit subject to 40 CFR Part 60, Subparts GG and Db.

[13] 152 to 158 MW units subject to 40 CFR Part 60, Subpart KKKK.

[14] 191 to 195 MW units subject to 40 CFR Part 60, Subpart TTTT.

[15] *Simple Cycle CT Technical Support Document*, U.S. EPA (March 2023), Docket ID No. EPA-HQ-OAR-2023-0072.

[16] EPA Simple Cycle Stationary Combustion Turbine EGUs Technical Support Document at pp. 7-8.

electricity quickly to immediately fill gaps in electricity output on the grid, and they can ramp down just as quickly. Other natural gas-fired electricity generators, such as CCGT or steam boiler plants, can take two to three times longer than SCGT power plants to start and ramp up to full load."[17]

EPA also incorrectly assumes that the role of natural gas-fired generation will decrease over the next 10 to 20 years, even as significantly more renewables are anticipated to come online, more coal units are retired, and electricity demand increases (particularly with the planned replacement of internal combustion engines with electric vehicles). EPA offers no factual support for these assumptions. Indeed, the EIA data discussed by EPA in its proposal contradicts EPA's conclusion as it shows that natural gas utilization has continued to increase as more renewables come one line[18]:

> "Moreover, the share of fossil generation supplied by coal-fired EGUs [electric generating units] fell from 46 percent in 2010 to 23 percent in 2021 while the share supplied by natural gas-fired EGUs rose from 23 to 37 percent during the same period. In absolute terms, coal-fired generation declined by 51 percent while natural gas-fired generation increased by 64 percent. This reflects both the increase in natural gas capacity as well as an increase in the utilization of new and existing gas-fired EGUs."[19]

EPA's NGSC TSD also incorrectly seems to attribute any increases of NGSC capacity factors to variables such as changes in natural gas prices, ignoring their growing role in supporting intermittent renewable generation. Again, those conclusions are contradicted both by Golden Spread's direct experience as well as by EIA who acknowledges the role of NGCC in support of intermittent renewable energy. EIA states, for example, that the average monthly capacity factor for NGSC units has grown annually since 2020 and that it surpassed 20% for two consecutive summer months in 2022.[20]

Though EPA's proposal does not evaluate NGSCs' essential role in supporting renewables, EPA nonetheless concedes that such backups are necessary. Without acknowledging that certain sources currently provide backup to intermittent resources (e.g., NGSCs), EPA speculates that necessary backup in the future will be provided by battery storage. This speculation is not supported by the administrative record. First, the use of NGSCs as the primary backup for renewables continues to grow. Second, the record does not demonstrate that technically adequate and cost-effective battery storage will be available in the volumes necessary by the deadlines established by EPA.

---

17 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Available at: https://www.eia.gov/todayinenergy/detail.php?id=55680#:~:text=Electric%20grid%20operators%20can%20use,generation%20from%20intermittent%20renewables%20grows

18 88 Fed. Reg. at 33278 ("As discussed in section IV.F.2 of this preamble and in the accompanying RIA, the post-IRA 2022 reference case projects that natural gas-fired combustion turbines will continue to play an important role in meeting electricity demand. However, that role is projected to evolve as additional renewable and non-renewable low-GHG generation and energy storage technologies are added to the grid.").

19 88 Fed. Reg. at 33256.

20 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Available at: https://www.eia.gov/todayinenergy/detail.php?id=55680

The North American Electric Reliability Corporation ("NERC") recently laid out the necessary interdependence between natural gas electric generating units and renewables, and the growing but still insufficient role of battery storage, as a "key finding" in its "2022 State of the Reliability Report."[21] NERC observed that CTs were "necessary balancing resources for reliable integration of the growing fleet of variable renewable energy resources," noting the importance of ensuring "uninterrupted delivery of natural gas to these balancing resources, particularly in areas where penetration levels of renewable generation resources are highest."[22] NERC has also raised concerns regarding the aggregate impact of inverter based (i.e., batteries) resources, noting that it was analyzing "large-scale grid disturbances involving common mode failures in inverter-based resources that, if not addressed, could lead to catastrophic events in the future," and that "the aggregate impact of these resources must be considered when developing policies, regulations, and requirements."[23] In its 2022 Report, NERC concluded:

> "Until storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain essential to providing the grid's rapidly increasing flexibility needs. Improvements in the mutual understanding of electricity and natural gas interdependencies enable operators in both industries to enhance reliability across energy delivery systems and reduce end-use customer exposure to energy shortfalls during extreme weather events."[24]

NERC's report demonstrates the complexity of this interdependence, the importance of planning and coordination by those with the experience and authority to manage the grid, and the consequences to consumers if these issues are not successfully managed.

The Proposed Rule does not consider the full gravity, complexity, and importance of the grid capacity, reliability, and affordability issues described by NERC that will be affected by this rulemaking. EPA is not merely proposing CO_2 emission standards. Rather, it is proposing a rule that will significantly affect the structure and operation of the grid, including the interdependency of key elements of the grid necessary to provide reliable and affordable electricity to the public, based on assumptions about the availability, interoperability and affordability of power generation and storage technology about which it has little expertise or experience. In so doing, EPA is stepping over its traditional jurisdictional lines and venturing into the "major question" zone on which it foundered in *West Virginia vs. EPA*.[25]

NGSC units are an integral and critical element of the efficient use of renewable energy, precisely the type of resources EPA seeks to significantly expand with this rulemaking. Restricting the use of NGSC units by imposing an artificial 20% capacity limit will disrupt the relationship between

---

21 NERC. 2022 State of Reliability Report. July 2022. Available at: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

22 *Id*. at p. viii.

23 NERC. Inverter-Based Resource Performance Issues. March 14, 2023. Available at: NERC Alert IBR Performance (https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf).

24 NERC. 2022 State of Reliability Report. July 2022. P. 45. Available at https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

25 *West Virginia v. EPA*, 142 S.Ct. 2587 (2023).

natural gas and renewable electric generating units, may actually be limiting renewable generation, and in some cases increase—not decrease—emissions due to curtailment of renewables.

IV. GOLDEN SPREAD OPPOSES EPA'S BSER DETERMINATION FOR NATURAL GAS COMBUSTION TURBINES.

A. Hydrogen Co-firing And CCS Are Not BSER For Natural Gas Combustion Turbines.

EPA acknowledges that there is no commercial scale electric generating unit in the United States currently operating with CCS technology or co-firing with so-called "green hydrogen" in any meaningful volumes. Nonetheless, EPA asserts that both of these commercially unproven and undemonstrated technologies (in the power generation sector) are BSER.

EPA's imposition of these technologies with the expectation that they will designed, installed, and operating by 2035[26] does not meet the criteria established by *Portland Cement v. Ruckelshaus*, which allows EPA to consider technologies that "may fairly be projected for the regulated future, subject to "the restraints of reasonableness," without "crystal ball speculation," and dependent on a showing of "achievability."[27] The Supreme Court observed, in the recent seminal case on Section 111(d), that "has been adequately demonstrated…imposes meaningful constraints" including that the "best system has a "proven track record."[28]

It is undisputed that there is no "proven track record" of CTs implementing CCS or hydrogen co-firing in any meaningful way, nor does the administrative record contain the necessary evidence or data to make EPA's assumptions any more than "crystal ball speculation."[29] EPA must not impose such speculative and draconian controls in the face of well-established data demonstrating that the nation's grid is already stressed, stresses that will increase as coal-fired units continue to shut down, while at the same time the demand on the grid is projected to increase.

Golden Spread adopts in full the detailed comments of the NRECA on the technical and economic challenges and barriers to the installation and operation of CCS and "green" hydrogen co-firing at CTs on the schedule proposed by EPA, and will not repeat those here. In addition, Golden Spread has specific knowledge regarding the infeasibility of CCS for its NGCCs.

---

26 The initial 2035 deadline is deceiving. As a practical matter, the technology must be designed, proven and available long before 2035 if the investments are to be made and the engineering and construction completed, such that when the switches are turned on in 2035 electricity will continue to be reliably and efficiently delivered in the quantities demanded by the public.

27 *Lignite Energy Council v. U.S. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (citing *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973)).

28 *West Virginia v. EPA*, 142 S.Ct. at 2629 (Kagan dissenting).

29 For example, EPA relies on Duke Energy's 2022 Climate Report to support the proposition that only hydrogen-burning peaking CTs will be constructed after 2040. 88 Fed. Reg. at 33255, n. 72. However, Duke's report provides absolutely no data or technical basis to support this assumption. EPA also cites NextEra's Energy Zero Carbon Blueprint, which contains similar aspirational projections regarding the future use of hydrogen to fuel natural gas power plants, but these projections are not accompanied by economic, technical and environmental data and studies. Aspirational projections contained in corporate strategy documents that are unsupported by any data or meaningful technical or economic evaluation are not evidence of a "proven track record" for purposes of establishing BSER.

Golden Spread's Mustang NGCC facility was the subject of a CCS feasibility study conducted by the University of Texas and funded in part by the Department of Energy.[30] In 2022 this study concluded that CCS was not feasible at the Mustang Station because, among other things, the limited availability of water and the high percentage of renewables in Golden Spread's service area. The study concluded that the "ideal site" factors for installing CCS at a CT facility included a service area with low renewables, CTs operating at a high capacity, and plentiful water. Thus, CCS is not a feasible option in Golden Spread's service area precisely because the already high penetration of renewables supported by Golden Spread's CTs. Regardless of the technology EPA speculates might be available, some of these decisive factors will never change for Golden Spread: water will not be plentiful (and continued drought is more likely), and the significant reliance on renewals is only going to increase, not decrease.

The technical and cost barriers set forth in NRECA's comments and demonstrated in the Golden Spread Mustang study apply with even greater force to NGSCs, such as Golden Spread's, that operate in regions with high renewable generation. The technical and cost barriers set forth in NRECA's comments and demonstrated in the Golden Spread Mustang study apply with even greater force to NGSCs, such as Golden Spread's, that operate in regions with high renewable generation and limited water availability. Thus, EPA's proposal to impose CCS (or hydrogen co-firing) on any NGSC that exceeds 20% capacity, or that batteries will be available to replace NGSCs on the scope and scale contemplated in the Proposed rule, is not BSER.

B. <u>Restricting The Availability Of Low Load NGSCs Will Have Adverse Environmental, Reliability, And Efficiency Consequences.</u>

Restricting the availability of low load NGSCs will force operators to rely on less efficient alternatives that could result in curtailments of renewable power and even increased emissions (relative to expectations). "Intermediate" load NGSCs will not fill that gap because EPA's proposed BSER (combinations of CCS and hydrogen co-firing), which is not economically or technically feasible for CTs generally, is even more infeasible for peaking NGSCs that run at less than 33% capacity. Thus, if low load NGSCs are restricted to units operating at less than 20% capacity, the primary practical alternative will be NGCC units, which are not well suited to fill in for NGSCs.[31] EPA is also considering equipping intermediate load NGSCs with steam injection, in addition to the economically and technically infeasible CCS/hydrogen co-firing, which EPA concedes would in part transform them into NGCC units.[32]

NGCC units require approximately two and one half hours (or even longer) to be at full load and optimum heat rate, from a cold state, and the boiler is adversely impacted by frequent cycling. Therefore, NGCC units are not well suited to efficiently and consistently backup intermittent generation such as wind and solar. The frequent cycling and ramping up and down of NGCC units causes thermal stresses on plant equipment and components, which increases maintenance costs and decreases the overall efficiency of the unit. NGSC units equipped with heat recovery

---

[30] University of Texas at Austin. Piperazine Advanced Stripper FEED Study. DE-FE0031844.

[31] As discussed elsewhere in these Comments and other public comments, EPA has not demonstrated that battery technology has a "proven track record" to be installed on the scope and schedule contemplated in this proposal to be a meaningful alternative to NGSCs and, if the use of low load NGSCs is significantly diminished, to NGCCs.

[32] 88 Fed. Reg. at 33324, n. 490.

steam generators ("HRSG") for purposes of steam injection face similar complexities.

NGCC units can practically supplement intermittent energy sources only if they are brought on-line and held at a minimum load on stand-by because they cannot start quickly from a cold state. However, doing so can limit the amount of renewable electricity generated, resulting in an overall increase in emissions. This result is because it is necessary at times to curtail wind generation, for example, due to excess generation, so that resources with slower start times (e.g., NGCC units or intermediate load NGSCs with steam injection) can stay online at minimum output and dispatched, to be readily available when the wind drops off. When NGCC units are operating, at any capacity, their power must and will be dispatched according to grid operating rules and protocols. As a result, if there is excess generation, dispatching power from NGCCs operating at stand-by capacity requires that power from some other source, e.g., wind, be curtailed.

This relationship between demand and available renewable generation capacity, coined the "duck curve" by CAISO, was first unveiled by NREL in 2008 and has been exacerbated by the increase in renewables capacity.[33] This phenomenon is not unique to California and is increasingly occurring in other parts of the country such as Texas and around the world where intermittent generation from renewables is increasing compared with generation from conventional sources.

As explained by ERCOT's Independent Market Monitor:

> "The prediction of the future shape of this curve once a large quantity of solar has entered has been referred to as the "duck curve" or, in Texas, the "dead armadillo curve." This curve indicates that conventional [thermal] resources will have to ramp rapidly each evening as the sun goes down and the solar resources' output falls sharply. Similarly, shifting weather patterns can cause wind output to fall rapidly and the timing of these decreases can be difficult to predict."[34]

Kenan Ogelman, Vice President of Commercial Operations in ERCOT, has stated:

> "The basic way to envision it is that load is still rising in the evening as people are returning home and increasing their electricity usage, but solar is dropping, so there is a need for a rapid increase in production of electricity. The contingency reserve service is designed to fill that need by having units capable of responding in 10 minutes or less to meet the additional demand."[35]

Thus, if the Proposed Rule is finalized as proposed and new NGSCs would have to operate at less than 20% of capacity, operators would be forced to keep less-flexible alternatives, such as NGCCs,

---

33 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Available at: *https://www.eia.gov/todayinenergy/detail.php?id=56880*

34 Potomac Economics, 2021 State of the Market Report for the ERCOT Electricity Markets at 2 (May 2022) ("2021 SOM Report"). Available at: https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-theMarket-Report.pdf.

35 State Energy Plan Advisory Committee, Report to the 87th Legislature, September 1, 2022 P. 58, available at: State Energy Plan Advisory Committee Report - Final.docx (competitivepower.org) p. 57 (https://competitivepower.org/wp-content/uploads/2022/09/State-Energy-Plan-Advisory-Committee-Report-Signed-Final.pdf).

running and available to prepare for the loss of solar and wind in the evening, as illustrated by the "duck curve." Using these alternatives that are less flexible than low load NGSCs has the unintended consequence of forcing curtailments of renewable energy and potentially increasing CO_2 emissions.

For NGCCs to effectively serve as back up and support for large amounts of renewable capacity, they must be kept at minimum load since they do not have the ability to start up quickly from a cold state. At minimum load, fuel is still being spent and energy is still being produced. This scenario can result in overall higher emissions since the renewable energy that could have otherwise served load with zero associated emissions must be curtailed to make room for NGCC.[36] Thus, in areas with high wind capacity (such as the region served by Golden Spread), reducing the availability of low load NGSC turbines and relying more on NGCCs can decrease generation by renewables and cause an increase, rather than a decrease, of expected CO_2 emissions. The fast-start flexibility provided by NGSC turbines on a grid-wide basis results in greater integration of renewable resources into the grid.

NGSC units that are available to quickly and economically operate at capacities greater than 20% are an essential part of operating an electric grid with significant renewable energy penetration and will be for the foreseeable future. NGCCs (and intermediate load NGCCs) are not economically or environmentally suitable alternatives to low load NGSCs. Further, the record does not support EPA's assumption that this role can be technically or economically assumed by battery power on anything approaching the scale and schedule contemplated in the Proposed Rule.

C. <u>New NGCCs And Co-firing Of Hydrogen Are Not Feasible In Water Scarce Regions.</u>

Incentivizing development of new water-intensive technologies such as NGCC, steam injected NGSCs,[37] or hydrogen co-firing is particularly problematic in water-starved areas such as Texas. In parts of the country with arid climates that are particularly susceptible to drought conditions, excessive reliance on these technologies may not be feasible or a desirable option. As is the case with Texas, these are also often regions with ample wind and solar resources.

The lack of rain and insufficient surface water in the geographic areas served by Golden Spread's Members have required reliance on the Ogallala Aquifer, which lies beneath the same area. EPA's adoption of a rule encouraging the development of more NGCC (or steam injected NGSCs) units to replace the use of NGSC units, would result in a large increase in water use. If EPA adopts such an approach, it will have serious implications to surface water and groundwater supply and can carry significant risks to the reliability of the grid. As discussed below, co-firing with hydrogen is even more demanding on water resources.

This impact to already scarce water resources in many areas, including Texas, is an issue that EPA is required to consider in the promulgation of an NSPS standard. Section 7411 of the Clean Air Act requires that EPA consider "any nonair quality health and environmental impacts" when promulgating a "standard of performance." In particular, the D.C. Circuit Court in *Sierra Club*

---

[36] Docket ID: EPA-HQ-OAR-2013-0495. Comments of Golden Spread Electric Cooperative. March 18, 2019. Available at: Regulations.gov

[37] The EPA solicited comment on the use of steam injection on intermediate load combustion turbines. 88 Fed. Reg. at 33324.

v. Costle stated that the NSPS Best System of Emission Reduction ("BSER") must reflect and balance other environmental considerations such as water usage.[38]

NGSC units are more water efficient than NGCC units, an important factor in wind generation areas such as Texas and the Southwest, where water is a scarce and sometimes decreasing resource. NGCC is a relatively water-intensive technology that can consume hundreds of millions gallons of fresh water per year. An NGCC power plant can consume more than 270 gallons per MWh of cooling water on an annual basis, whereas a NGSC unit typically consumes only 41 gallons per MWh.[39]

For Golden Spread, the water level in the local aquifers near AEEC has declined over the last several years and is becoming scarce. Consequently, technology evaluations must consider the future availability and value of water among the various selection criteria. Considering Golden Spread's need for operational flexibility to startup and shutdown multiple times daily, and water resource availability issues, the selection of additional NGCCs may not be technically feasible.

NGSC units equipped with steam injection are water intensive, as they effectively incorporate water-based steam technology into their operation. This makes them similarly unsuitable for arid regions of the country, regions which frequently have high potential for renewable energy.

Hydrogen production and related co-firing is also a water and energy intensive process as described by EPA in its proposal:

> "New combustion turbine models designed to combust hydrogen, and those potentially being retrofit to combust hydrogen, may be co-located with electrolyzers that produce the hydrogen the facility will use. In such instances, water scarcity could be exacerbated in some areas by the freshwater demands of electrolytic hydrogen production, which could pose a particular challenge for vulnerable communities. As such, electrolyzer siting will need to take water availability into account."[40]

Modeling tools made available by turbine manufacturers illustrate both the water and energy intensity of hydrogen co-firing for NGSCs. One of these models calculates that co-firing a 190 to 200 MW NGSC with 90% hydrogen would consume approximately 33,000 gallons and 35 MW of parasitic load per hour, while co-firing with 30% hydrogen would use

---

[38] 657 F.2d 298 (D.C. Cir. 1981) ("For example, an efficient water intensive technology capable of 95 percent removal efficiency might be "best" in the East where water is plentiful, but environmentally disastrous in the water-scarce West where a different technology, capable of only 80 percent reduction might be "best." . . . The standard is, after all, a national standard with long-term effects.").

[39] Alternative cooling technologies that have been considered for NGCCs (e.g., air cooled condensers, or ACC), but they result in significant efficiency losses and decreased in net output. According to a study conducted by EPRI, "dry cooling imposes a heat rate and lost-capacity penalty on a plant that can range up to 25% during the hottest hour of the year and exceed 8% for over 1,000 hours at a hot, arid site. On an annual basis, plant output is reduced by about 2%."[39] Thus, the ACC equipped NGCC plant will burn more fuel and generate more air emissions to produce the same net power produced by a NGCC unit using a traditional evaporative cooling tower. Furthermore, demand for energy typically peaks during hot temperatures, so this loss of efficiency would be significant and more pronounced.

[40] 88 Fed. Reg. at 33414.

approximately 5,158 gallons and 5.5 MW of parasitic load per hour.[41] Putting this in context, at an approximately 50% capacity factor—without hydrogen co-firing—such a unit might typically consume approximately 6.1 million gallons per year of water. The same unit with 30% hydrogen co-firing would increase its water consumption to approximately 23.5 million gallons per year, and 90% hydrogen co-firing would require approximately 150 million gallons per year.

While EPA acknowledges that the water consumption associated with co-firing hydrogen may be an issue for vulnerable communities, the only solution EPA proposes is the potential future use of sea water,[42] which is not an option for regions such as Golden Spread's service area. Hydrogen co-firing itself does not have a proven track record for CTs, and the feasibility and affordability of widespread use of reclaimed seawater to support hydrogen co-firing in the energy generation sector has not been demonstrated by EPA in the administrative record.

V. THE PROPOSED ALLOWANCE FOR SYSTEM EMERGENCIES MUST BE CLARIFIED OR REVISED.

EPA's proposal includes a provision that exempts electricity sold during a "system emergency" from counting towards applicable subcategorization capacity thresholds (e.g., the 20% threshold for low capacity CTs). EPA states that this allowance is necessary to maintain system reliability and minimize overall costs by not imposing the CCS/hydrogen co-firing requirements when CTs exceed the 20% cap due to emergencies. This exemption will not achieve its intended goal and cannot be depended on as a tool to ensure system reliability, particularly when combined with EPA's proposal to decrease the low-capacity threshold to 20%, a limit which is inconsistent with the use of NGSCs as an integral element of the renewable energy infrastructure.

The exemption would preclude a low load unit from being categorized as intermediate or peaking unit due solely to increased capacity use during a system emergency. However, this exemption does not protect an operator from other potential associated air emission violations that might occur during a system emergency.

Under EPA's proposal, for example, a new "low load" simple cycle would be permitted to operate at no more than 20% capacity factor. Such an air permit would also establish maximum allowable emissions for other pollutants (e.g., NOx, SOx, particulates) based on that same enforceable 20% cap. If the unit operates at 23% capacity one year, with 5% of that capacity attributable to system emergencies, the unit would still be classified as a low load unit for purposes of the greenhouse gas emission standards established by this rulemaking. However, the generator would have potentially violated its permitted emissions of other pollutants which were based on the permitted 20% capacity factor. EPA's proposed exemption for purposes of regulating greenhouse gas emissions will not provide operators any protection from enforcement actions associated with excess emissions of other pollutants emitted during such a system emergency.

---

41 GE Gas Power: Hydrogen and CO2 Emissions Calculator. Accessed August 2023. Available at: https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines/hydrogen-calculator

42 *Id.*

The proposed exemption would also decrease rather than enhance grid reliability. Regional Transmission Organizations and Independent System Operators use a market tool called a Reliability Unit Commitment ("RUC") to require an electric generating unit to participate in the wholesale market during operating reserve supply shortage. Generators are required to respond to an RTO/ISO's RUC instructions.[43] Golden Spread's units regularly receive RUC instructions aimed at maintaining grid stability and reliability. However, at the same time, Golden Spread will not dispatch a unit if there is a potential for an air permit violation, putting the company in an impossible position. Golden Spread assumes that other generators have similar policies. The combination in the Proposed Rule of an incorrect 20% cap on low-capacity units, and the mirage of an exemption from that cap for system emergencies, will not provide operators with regulatory relief nor the grid with reliability.

EPA can correct this problem by maintaining the current 33% capacity limit such that the likelihood of exceeding the low-capacity threshold is significantly decreased, and clarifying and modifying the system emergency exemption such that system emergency allowances provide meaningful protection applicable to all air emission limits, not just greenhouse gas limits.

VI. THE PROPOSED RULE'S APPLICABILITY MUST BE ON A GENERATING UNIT, NOT PLANT-WIDE, BASIS.

The discussion of applicability of the standards to existing CTs in the Proposed Rule, and the economic and environmental projections associated with it, is based on individual generating unit capacity, with 300 MW being the primary cut-off size for existing CTs. However, without any meaningful public notice, EPA on June 7, 2023, after the commencement of the public comment period, submitted an undated memorandum into the docket titled *Integrated Proposal Modelling and Updated Baseline Analysis – Memo to the Docket*. Within the Memo, EPA included the following statement:

> "[W]hile the proposed rulemaking applied that threshold on a unit-level basis, and all of the modeling performed to date does the same, comments from stakeholders to date have led the EPA to also consider applying the threshold on a plant-level basis. EPA is considering the appropriate MW threshold for such a plant-level approach and whether such an approach should also include a unit-level MW threshold."[44]

Thus, while EPA concedes that the Proposed Rule and all its modeling to date has been based on unit-level applicability decisions, it nonetheless states that it is considering an entirely different plant-level approach to applicability that is not part of the Proposed Rule. This change likely would constitute a massive expansion of the final rule, significantly increasing the number of existing CTs that would be subject to the rule. This expansion would require additional analysis by EPA to determine how many existing natural gas power plants are composed of CTs with under 300 MW capacity that would not be subject to the rule as proposed but would be subject to the rule if capacity were evaluated on a plant-wide basis.

---

[43] In SPP, for example, a RUC is defined as: SPP process to assess resource and Operating Reserve adequacy for the Operating Day, commit and/or de-commit resources as necessary, and communicate resource commitments or de-commitments to the appropriate Market Participants, as necessary.

[44] Memo to the Docket at p. 5.

Finalizing a plant-level approach to bring existing CTs into a final rule would violate the APA. EPA admits that it did not propose such an applicability test, and that none of its modeling to date evaluated this approach. This concept is revealed in a few sentences in an undated *Memo to the Docket* focusing on technical modeling issues filed with no meaningful public notice after the public comment period opened. EPA has not made any specific proposal that the public can evaluate or on which it can comment. Since EPA has not modeled a plant-wide applicability approach, it does not know the economic or environmental consequences of such an approach, or whether it is feasible. Such a significant change in any final rule, based on a few sentences in an undated memo to the docket about modeling filed in the docket after the commencement of the comment period, could not reasonably be considered a "logical outgrowth" of the Proposed Rule.

Golden Spread opposes the concept of making applicability determinations in this rulemaking for existing CTs on a plant-wide basis. However, if EPA is considering such an approach, it must re-propose the rule with a specific proposal on the applicability issue, and accompany that proposal with the necessary economic, technical, and environmental data and modeling supporting the proposal. To do otherwise would violate the APA.

VII. CONCLUSION

If EPA moves forward with the Proposed Rule, Golden Spread urges EPA to do the following:

- Retain the existing capacity factor of 33% for CTs as the threshold for low-load CTs.
- Decline to impose CCS and "green" hydrogen co-firing as BSER for CTs, particularly for NGSCs.
- Revise the "system emergency" capacity allowance to provide meaningful regulatory and enforcement protection to generators.
- Decline to adopt a plant-wide approach to applicability determinations.

Golden Spread urges the EPA to consider the critical and integral role that NGSCs serve in the existing and growing renewable power infrastructure. It is not reasonable to evaluate and regulate NGSCs on a generic and nationwide basis as power generation units (i.e., the "average NGSC" across the nation) without regard to the varying roles that NGSCs play in the grid. The extent to which the grid depends on renewable energy, and thus the significance of the contribution of NGSCs, varies considerably around the country. Failing to take these variabilities into account will obscure the crucial and growing role NGSCs play in the renewables infrastructure, and result in regulatory outcomes inconsistent with EPA's stated goal of increasing the nation's reliance on renewable energy. Thus, EPA should give significant weight to Golden Spread's Comments, based on its experience in a vast geographic service area where renewable generation penetration is the highest in the country (twice the national average), and whose NGSCs play an integral role in supporting this success story.

Golden Spread appreciates the opportunity to submit input on the Proposed Rule. Should you have any questions please contact Ruth Calderon, Legislative, Regulatory & Policy Manager at rcalderon@gsec.coop or (806) 349-5205.

Iowa Utilities Board

Erik M. Helland, Chair
Joshua J. Byrnes, Board Member
Sarah M. Martz, Board Member

July 25, 2023

Michael S. Regan
Administrator
United States Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20004

RE: EPA-HQ-OAR-2023-0072

Dear Administrator Regan,

The Iowa Utilities Board (IUB) and the Iowa Consumer Advocate hereby submit the following comments in regard to the Environmental Protection Agency's proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (the proposed rules).

The proposed rules establish new restrictions that must be imposed by states for carbon dioxide (CO_2) emissions from electric generating units (EGU). The new restrictions differentiate based upon the fuel type, retirement date, and the annual capacity factor of the facility. For example, a coal EGU that will not commit to retirement by 2040 must implement carbon capture and storage and reduce CO_2 emissions by 88.4%. The proposed rules are driven by concerns about air quality impacts from continued operation of coal and natural gas units but are entirely unconcerned with the negative impacts of a lack of electricity in the bulk power system. The proposed rules remove state flexibility to keep dispatchable generating facilities available and significantly impact the reliability of the nation's bulk electric grid.

It is deeply concerning that the proposed rules are being promulgated in a regulatory vacuum without any real engagement on the issue of their actual impact on the reliable and cost-effective delivery of electricity to the American public. Concern transforms into disbelief given that a mere two months before the U.S. Environmental Protection Agency (EPA) released these proposed rules, the EPA announced the Joint Memorandum on Interagency Consultation on Electric Reliability between the EPA and U.S. Department of Energy (DOE). In releasing this agreement, which is alleged to ensure due and proper communication and consideration of electric system reliability in the United States, EPA Administrator Regan declared, "A reliable electric power system is essential to our national security, continued economic growth and the protection of public health."[1] While we wholeheartedly agree with this statement, "essential" doesn't mean what Administrator Regan apparently thinks it means.

[1] EPA and DOE joint press release, March 9, 2023.

"Essential" means indispensable, basic, or necessary.[2] The proposed rules treat reliability as merely one of many considerations, and do a poor job in making that consideration. The North American Electric Reliability Corporation, one of several entities tasked with ensuring the reliability of our bulk power system, has correctly stated that electricity is a key component in the fabric of modern society and that our bulk power supply has faced increasing and unprecedented challenges arising from our transition to renewable energy, increased storm intensity and frequency, cyber attacks, physical attacks, and volatility in the energy fuel markets.[3] A continuous reliable electric supply within very tight frequency boundaries is a critical element to the continued existence of the United States.[4] It is necessary for sustaining water supplies, production and distribution of fuel, communications and everything else that is a part of our economy. Blackouts over a few days in Texas in February 2021 were reported by the State of Texas to have caused 246 deaths.[5] That is what "essential" means.

It defies belief that in the mere two months between the EPA announcing its agreement to work with DOE and the publication of the proposed rules that the EPA duly consulted and considered the significant impact on the essential service of literally keeping the lights on. The proposed rules are rushed, the record does not meaningfully consider the impact of this truly essential service, and EPA myopically pursues a narrow goal at the expense of larger societal benefits like life, heat, and jobs.

The policy question at issue with the proposed rules is how to control air pollution without compromising how to best protect the national security, public health, and our economy by ensuring a reliable bulk electric system. Who is to answer this major question? The Clean Air Act gives us clear direction in regard to the first element. Air pollution prevention (that is, the reduction or elimination, through any measure, of the amount of pollutants produced or created at the source) and air pollution control at its source are the primary responsibility of States and local governments.[6] The proposed rules seem to have missed that key concept; instead, the EPA is seeking to aggregate to itself the authority to impose its own preferences. If Congress intends to shift that responsibility to the EPA, a decision of such magnitude and consequence rests with Congress itself, or an agency acting pursuant to a clear delegation from that representative body.[7]

The EPA seems to subscribe to the unique theory that it can expand its jurisdiction by losing cases before the Supreme Court.[8] Perhaps a better theory would be to let those who have been lawfully assigned oversight exercise that oversight.

In regard to the key issues of resource adequacy, grid reliability, and the appropriate generation mix to ensure a reliable bulk electric system to protect national security, public health, and our economy, the room is already quite crowded. State public utility boards and commissions, state energy offices, regional transmission planning organizations or independent system operators,

---

[2] Merriam-Webster, 11th edition.
[3] NERC 2022 State of Reliability, July 2022.
[4] Report of the Commission to Assess the Threat to the United States from Electromagnetic Pulse Attack, p.17 (April 2008)
[5] February 2021 Winter Storm-Related Deaths – Texas. Texas Department of State Health Services. (12/31/2021)
[6] 42 U.S.C. 7401(a)(3)
[7] See West Virginia v. EPA, 142 S.Ct. 2587, at 2616 (2022)
[8] See Massachusetts v. EPA (2007), Utility Air Regulatory Group v. EPA (2014), Michigan v. EPA (2015), West Virginia v. EPA (2021)

local balancing authorities, local electric utilities, the North American Electric Reliability Corporation and its component entities, the Federal Energy Regulatory Energy Commission and the larger umbrella of the US Department of Energy, all have critical and overlapping roles to play in these determinations. As the EPA's agreement with DOE shows, the EPA does not have the expertise to effectively engage in these issues. But that seemingly did not slow down the freight train of regulatory overreach represented by the proposed rules. The EPA should have meaningfully consulted, sought, and provided input with those of us who are tasked with supporting this essential service before leaping into an area where many wisely fear to tread.

The consequences of a wrong decision can kill people and cripple economies, and less arrogance and more humble inquiry is necessary. Again, if Congress intends to shift responsibility for these major questions to the EPA, it needs to clearly say so. If any of the responsible entities feel they need EPA assistance to decide how to best keep the lights on, we will ask. But more relevantly, the EPA should ask these responsible entities how to not cause death and economic catastrophe in seeking to implement its relatively narrow jurisdictional responsibilities. The EPA must be mindful of the bigger picture and not get myopically lost in forever seeking minor incremental benefits irrespective of the costs or impacts.

In regard to the general propriety of the proposed rules as the establishment of best demonstrated technology (BDT) within the limitations described by the Supreme Court in *West Virginia v. EPA*, we will largely leave that issue for state environmental agencies, utilities, and other stakeholders. Perhaps mandating expensive emerging technologies and limiting capacity factors based upon retirement dates for dispatchable electric generation sources is somehow fundamentally different than the EPA's prior effort to force transition to renewables regardless of impact to the bulk power system, which was rejected by the Supreme Court just last year.

In the context of reliability, we are primarily concerned about the use of capacity factors and retirement dates in the identification of affected EGUs in the proposed rules. The assignment of capacity factors and the determination of prudent retirement dates must be driven by actual production ability, the need to meet customer electric demand, and the prudency of the operation of each generation type under differing times and conditions. Factors such as weather, transmission availability, demand, fuel availability and countless other considerations go into these decisions, which are at the core of maintaining a reliable electric system in the United States. The availability of dispatchable power on demand, instead of being reliant solely on intermittent generating resources like wind and solar, is essential to ensuring that the North American grid continues to serve the 400 million consumers in the USA and Canada, since electricity is generated and consumed simultaneously. These daily momentous decisions require real data in real time, balancing a constantly changing dynamic system that people dedicate their lives to understanding a small portion of and which has been described as the largest and most complex machine in the world.[9] Through the proposed rules, the EPA is not just meddling in reliability determinations that are outside of its expertise, the EPA is incentivizing misinformation in regard to actual prudent retirement dates and actual ability to generate power, throwing a regulatory monkey wrench into an already-stressed machine.

Numerous state and federal incentives and the demands of customers are driving the growth of renewable energy in America. Iowa now has more than 12,000 MW of renewable generation

[9] Multiple sources. This should get EPA started: https://www.popularmechanics.com/science/energy/a44067133/how-does-the-power-grid-work/

with additional wind and solar projects being added at a rapid rate. The Midwest Independent System Operator, the electric grid operator for much of Iowa, reported a best-int-the-nation average of 333,012 GWh of renewable generation for the fourth quarter of 2022[10] — all while keeping the lights on and moving at a pace of adoption and integration into the grid that manages reliability concerns.

Those entities responsible for maintaining the continued reliable electric supply need the ability to decide the appropriate mix of renewable and dispatchable electric generation. The rules proposed in EPA-HQ-OAR-2023-0072 will infringe upon and impede the ability to make those decisions and will negatively impact the essential reliability of the bulk electric system in Iowa.

The EPA has failed to consult or consider the wider impacts of its regulation. We therefore oppose the regulations and request the rulemaking be terminated.

Sincerely,

/s/ Jon Tack

Jon Tack
General Counsel
Iowa Utilities Board

/s/ Lanny L. Zieman

Lanny L. Zieman
Consumer Advocate
Office of Consumer Advocate

[10] US Renewables Tracker, S & P Global (3/03/2023)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2023–2024 Winter Reliability Assessment

November 2023

WRA Infographic | WRA Video

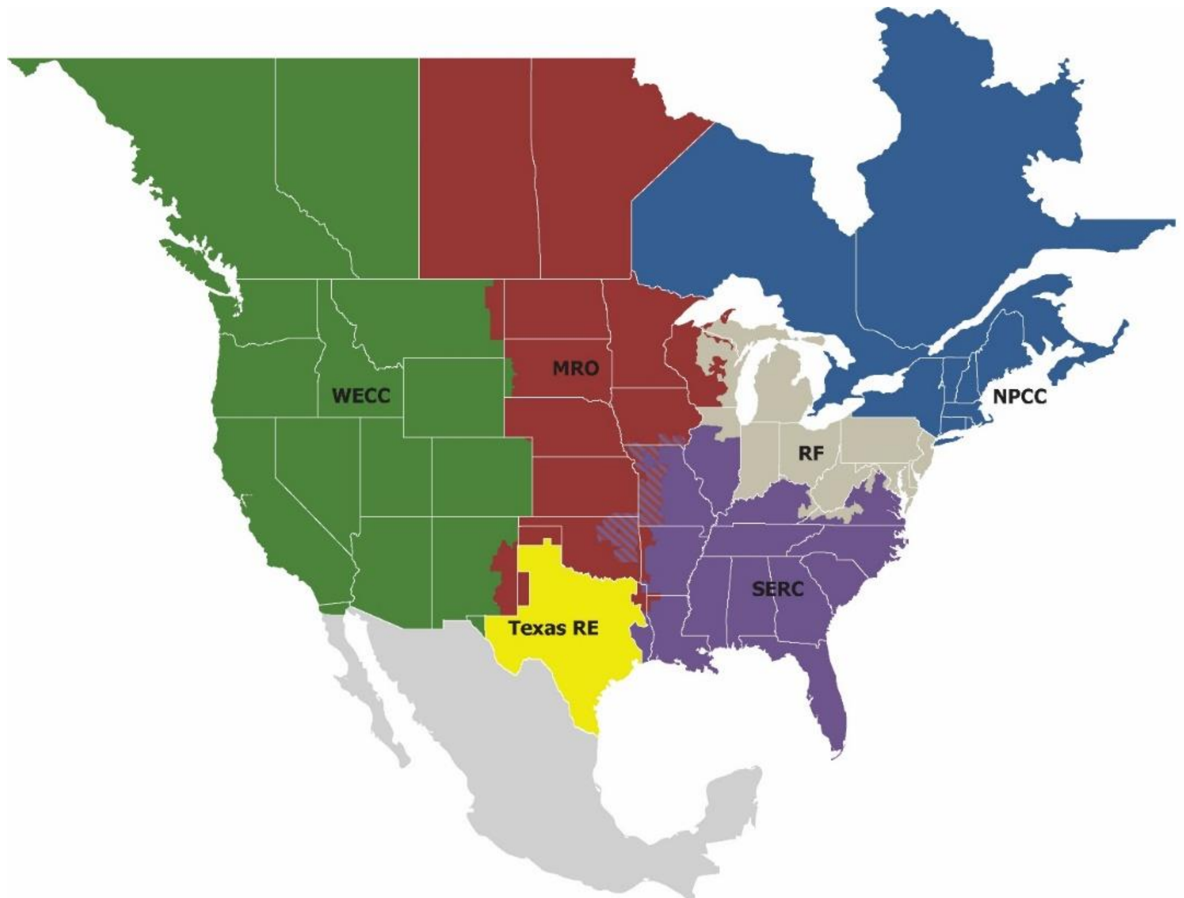
Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2023–2024 Winter Reliability Assessment (WRA)* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

This reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter:

1. **A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions** (**Figure 1**). Prolonged, wide-area cold snaps threaten the reliable performance of BPS generation and the availability of fuel supplies for natural-gas-fired generation. As observed in recent winter reliability events, over 20% of generating capacity has been forced off-line when freezing temperatures extend over parts of North America that are not typically exposed to such conditions. When electricity supplies become constrained, BPS system operators can face a simultaneous sharp increase in demand as electric heating systems consume more power in cold temperatures. These areas (see **Figure 1)** are at greatest risk for electricity supply shortfalls this winter:

    - **Midcontinent ISO (MISO):** New wind and natural-gas-fired generation and the extension of some older fossil-fired plants have increased available resources this winter by over 9 GW from 2022. Recently, MISO implemented a seasonal resource adequacy construct that more effectively values risks and resource contributions that vary by time of year. Like prior years, an extreme cold-weather event that extends into MISO's southern areas can cause high generator outages from inadequate weatherization or insufficient natural gas fuel supplies.

    - **MRO-SaskPower:** Reserve margins have fallen this winter by eight percentage points when compared to the previous winter due to increased peak demand projections, the retirement of a natural-gas-fired unit (95 MW), and planned generator maintenance. High numbers of forced generator outages or wind turbine cold temperature cutouts can lead to operating reserves shortfalls at peak winter demand levels.

    - **NPCC-Maritimes:** Peak demand growth has been offset by additional resource capacity and import agreements for the upcoming winter, causing reserve margins to rise by over two percentage points compared to 2022. Demand levels at the forecasted peak can still strain the area's firm supplies and lead to operating mitigations or energy emergencies.

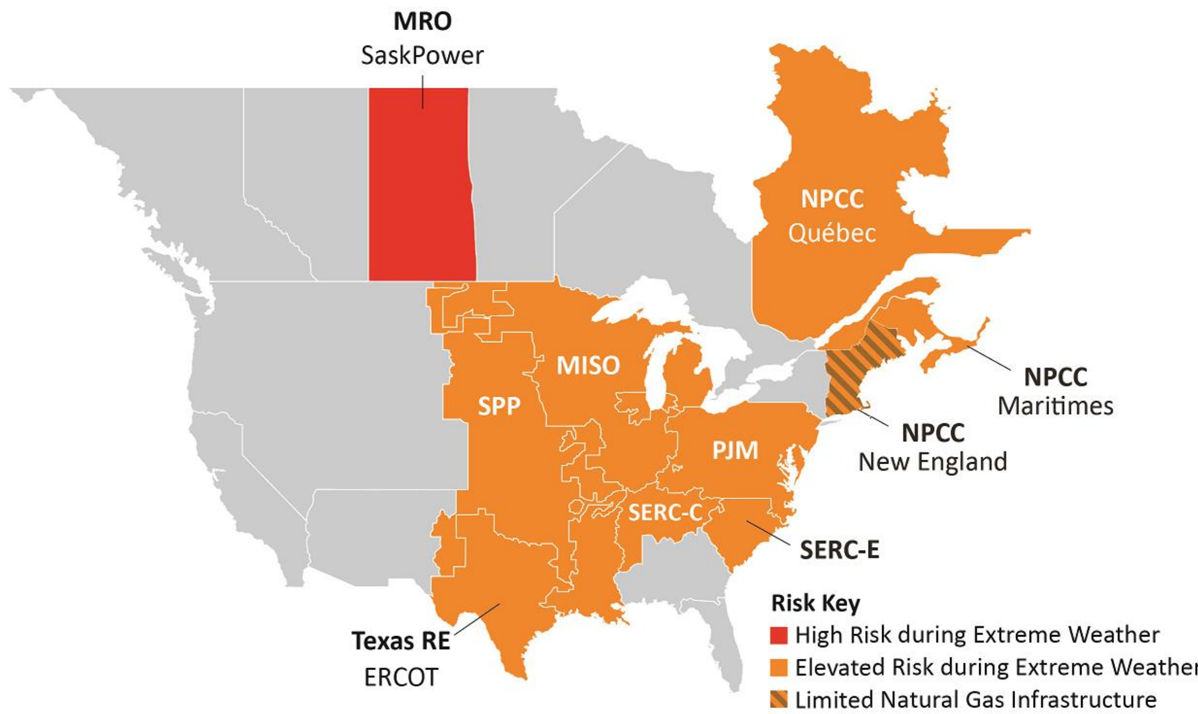


Figure 1: Winter Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

    - **NPCC-New England:** The capacity of natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs. Potential constraints on the fuel delivery systems and the limited inventory of liquid fuels may exacerbate the risks for fuel-based generator outages and output reductions that result in energy emergencies during extreme weather. ISO-New England (ISO-NE) introduced the Inventoried Energy Program this year as an interim measure to address energy security concerns. The program provides compensation for generators that maintain inventoried energy for their assets during extreme cold periods. The program is also planned for 2024–2025 winter while ISO-NE develops more comprehensive energy security measures for regulatory approval.

- **NPCC-Québec:** An increase in forecasted peak demand and additional firm export commitments have resulted in lower reserve margins for the upcoming winter. Despite having reliable performance from hydroelectric generation in winter, non-firm imports may be needed to meet operating reserve requirements if demand levels exceed the forecasted peak.
- **PJM, SERC-East, and SERC-Central:** A severe cold weather event that extends to the Southern United States can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have changed little in these areas since Winter Storm Elliot caused energy emergencies across the area in 2022. PJM and SERC have adequate resources for normal winter conditions; however, their generators are vulnerable to derates and outages in extreme conditions.
- **Southwest Power Pool (SPP):** The Anticipated Reserve Margin (ARM) of 38.8% is over 30 percentage points lower than last winter; this is driven by higher forecasted peak demand and less resource capacity. While the reserve margin is adequate for normal forecasted peak demand and expected generator outages, higher demand levels and outages that have occurred during extreme cold weather result in shortfalls that can trigger energy emergencies. The vast wind resources in the area can alleviate firm capacity shortages under the right conditions; however, energy risks emerge during periods of low wind or forecast uncertainty and high electricity demand.
- **Texas RE-ERCOT:** Like other assessment areas in the Southern United States, the risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. The risk of reserve shortage is greater than last winter due primarily to robust load growth that is not being met by corresponding growth in dispatchable resources. ERCOT is taking steps to procure additional capacity ahead of winter that can reduce the likelihood of energy emergencies. Additionally, ERCOT implemented a new firm fuel supply service in its market that is expected to partially offset the lost generation capacity that can occur when natural gas supplies are limited. Electricity demand in Texas rises sharply as extreme cold temperatures add to winter operating challenges and energy shortfall risks.

2. **Generator fuel supplies remain at risk during extreme, long-duration cold weather events.** Fuel assurance is vitally important to meeting winter electricity demand across North America. Natural-gas-fired generator availability and output can be threatened when natural gas supplies are insufficient or when the flow of fuel cannot be maintained. During Winter Storm Elliott, natural gas production rapidly declined with the onset of extreme cold temperatures, contributing to wide-area electricity and natural gas shortages.

Currently, natural gas production, transportation, storage, and a significant portion of the BPS link together to form a single interconnected energy delivery system that extends from the natural gas wellhead to end-use electricity and natural gas customers. The operation of this interconnected energy system can be disrupted when natural gas fuel supplies are not available for electricity generation as well as when electricity is not available to operate electricity-driven compressors and other critical infrastructure components in the natural gas supply chain. Recent extreme cold weather events have shown that energy delivery disruptions can have devasting consequences for electric and natural gas consumers in impacted areas.

Winter Storm Elliott demonstrated the wide-area consequences for BPS reliability that can result from reduced natural gas production during periods of extreme cold weather. In addition to wellhead impacts on production, natural-gas-fired generating units that lacked firm supply or transportation contracts to meet their winter peak electrical output faced challenging and often insurmountable fuel procurement issues when natural gas supply and available pipeline capacity became scarce. During Winter Storm Elliott, natural-gas-related fuel outages occurred alongside generator outages, derates, and failures to start that resulted from freezing issues and mechanical/electrical issues that are closely correlated with falling temperatures.

The joint *FERC-NERC-Regional* Entity *Joint Inquiry into Winter Storm Elliott* made the following recommendations related to adequate fuel supply assurance and other matters:[1]

- Establishing reliability rules for natural gas infrastructure
- Improving communication and business practices between industries
- Assessing Balancing Authority (BA) reliability commitment processes for addressing potential capacity shortages during forecasted cold weather events

To enhance situational awareness across impacted interconnected energy delivery systems, the FERC-NERC report also included a more immediate recommendation that BPS operators and natural gas industry controllers convene to establish control room to control room operational communications protocols that can be invoked when extreme cold weather approaches and that these protocols remain in place over the duration of the event.

[1] FERC Winter Storm Elliott Report

Coal is also an important fuel for electricity generation in winter. Generator owners report fewer coal supply issues compared to last winter. Normal rail transportation services are available and coal stocks are at a high level compared to historical averages. Some coal fired generation that relies on barge shipments in inland waterways could be impacted by drought restrictions that limit barge loading.

3. **Load forecasting in winter is growing in complexity. Underestimating demand is a risk to reliability in extreme cold temperatures.** Extreme cold temperatures and irregular weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar photovoltaic (PV) distributed energy resources (DER) add to the load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice; this can expose BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme winter conditions.
4. **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, Reliability Coordinators (RC) and BAs may curtail transfers for various reasons with established procedures and protocols. While the curtailments alleviate an issue in one part of the system, curtailments can contribute to supply shortages or affect local transmission system operations in another area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection. For winter 2023–2024, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MRO-SaskPower, NPCC-Maritimes, NPCC-New England, SERC-Central, and SERC-East. A wide-area cold snap that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.
5. **New cold weather Reliability Standards in place at the start of the 2023–2024 winter are aimed at improving coordination between Generator Owners/Operators and BPS Operators.** New cold weather Reliability Standards adopted by the NERC Board of Trustees (Board) in June 2021 went into effect in the United States earlier this year. Generator Owners (GO) and Generator Operators (GOP) are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, Transmission Operators (TOP), and BAs for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation.
6. **Industry responses to NERC's Level 3 Alert - Cold Weather Preparations for Extreme Weather Events–III indicate that generator winter preparations are on a positive trend, but freezing temperatures remain a concern for some generators.** In May, NERC issued a Level 3 essential actions alert to BAs, TOPs, and GOs. The alert highlighted actions to increase readiness and enhance plans to reduce risk for the upcoming winter and beyond. Additionally, recipients of the alert were required to respond to questions that support NERC's review of progress toward mitigating winter reliability risks. The responses indicate GOs have determined cold weather temperature limits for their generators and taken steps to assess and prepare critical components to operate at these temperatures. Many GOs, however, noted that generator unit and auxiliary component mechanical failures from past cold weather events remain a concern for the upcoming winter. Problem areas include improper heat tracing, frozen instrumentation and control equipment, generator circuit breaker tripping in low temperatures or low air pressures, and wind turbine blade icing.

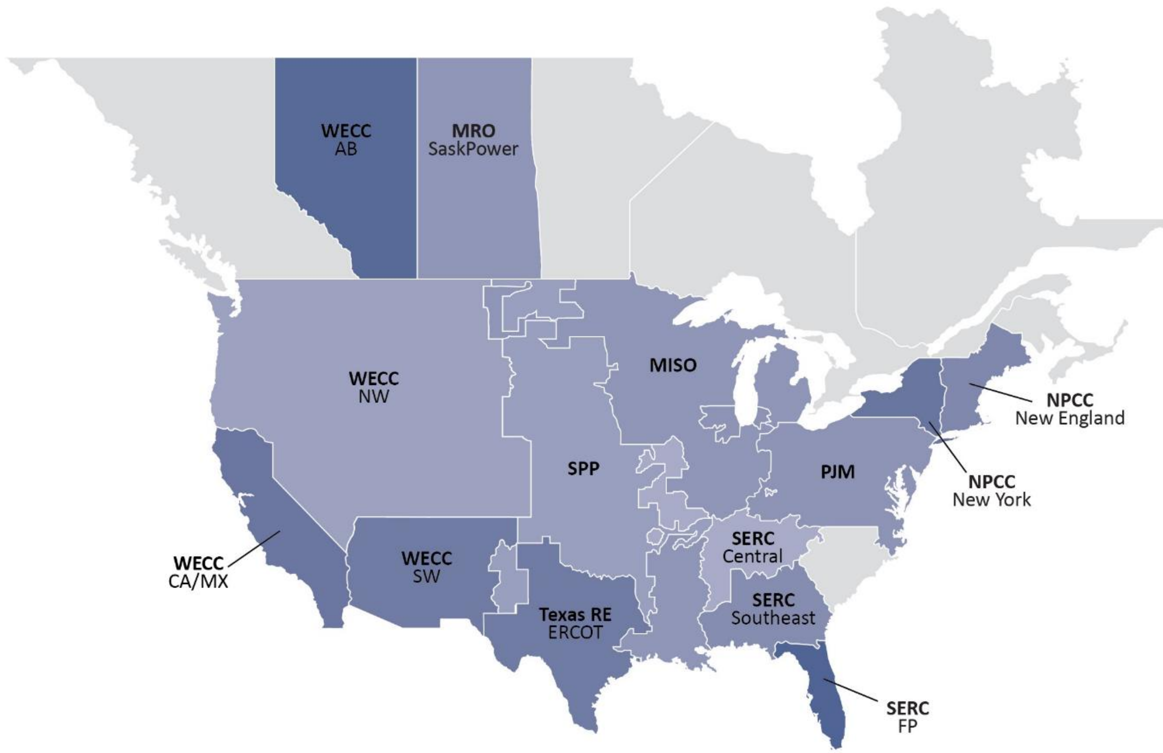
Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should be trained and familiar with manual load shedding plans prior to winter and review procedures in advance of severe winter weather.
- TOPs, BAs, and GOs should implement the essential actions identified in the NERC Level 3 alert, Cold Weather Preparations for Extreme Weather Events–III, and should take recommended weatherization steps prior to winter.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electricity and natural gas conservation.

Risk Highlights

Over the past 11 years, five cold weather events have jeopardized Bulk Electric System (BES) reliability by triggering unplanned cold weather-related generation outages. To maintain BES reliability during Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022, BES operators were required to shed firm load. During both winter storms, numerous electrical and mechanical issues rendered significant portions of the impacted areas' thermal generation fleet unavailable while natural gas supply and transportation issues prevented numerous otherwise available natural-gas-fired generators from supplying much needed electrical energy. Moreover, a significant portion of generating units failed to perform at temperatures above their own documented minimum operating temperatures.



Natural-Gas-Fired Generation

	Peak Winter Capacity	Contribution to Total Winter Resource Mix
MISO	67.5 GW	46%
MRO-SaskPower	2.1 GW	46%
NPCC-New England	17.3 GW	54%
NPCC-New York	24.5 GW	66%
PJM	84.9 GW	47%
SERC-Central	22.7 GW	44%
SERC-Florida Peninsula	50.6 GW	79%
SERC-Southeast	31.5 GW	51%
SPP	27.4 GW	41%
Texas RE-ERCOT	54.2 GW	62%
WECC-AB	11.4 GW	75%
WECC-CA/MX	39.9 GW	65%
WECC-NW	31.0 GW	39%
WECC-SW	18.2 GW	62%

All other assessment areas have less than 35% natural gas fired generation contribution to winter resource mix.

Figure 2: Natural-Gas-Fired Generation Capacity Contributions to 2023–2024 Winter Generation Mix

Generator Fuel Supply Risk

As noted in past winter reliability assessments, the performance of the thermal generating fleet is critical to winter operations. The electric and natural gas industries continue to work through the recommendations contained in the *FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South-Central United States.*[2] The final report on Winter Storm Elliott—the 2022 storm that contributed to power outages for millions of electricity customers in the Eastern half of the United States—recommends completion of cold weather reliability standard revisions stemming from 2021's Winter Storm Uri and improvements to reliability for the U.S. natural gas infrastructure.[3] What has become clear is that the natural-gas-electric system has now become fully interconnected, each requiring the other to remain reliable (i.e., impacts on one system can impact the other). These considerations should drive higher levels of coordination to ensure sustained reliable operation of this interconnected system.

Natural Gas Supply to Generators

Natural-gas-fired generation is vitally important to meeting winter electricity demand across much of North America (Figure 2). Furthermore, the natural gas industry relies on electricity to power some of its critical components. For instance, some compressors run on electricity while others are fueled by natural gas. This means that the natural gas industry depends on the delivery of electricity to run as intended, and as stated in many other places, the electric industry depends on the delivery of natural gas. This can exacerbate the scale of impacts when either industry is threatened.

[2] The February 2021 Cold Weather Outages in Texas and the South-Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

[3] FERC Winter Storm Elliott Report

Generator availability and output can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel. The BES's ability to deliver electricity was put at risk by past natural gas production declines during periods of extreme cold weather. As Winter Storm Elliott demonstrated, this is the case even in areas of North America where cold weather is common. Wide-area extreme cold events increase the likelihood of natural gas production declines and result in increased demand for natural gas by local distribution company (LDC) customers and natural-gas-fired electric generators. Wide-area events can also concurrently render multiple grid BA areas energy deficient and thus preclude an impacted BA from importing the electricity it requires to meet BA load even when transmission to support such transfers is available. Longer duration events increase the risk that the imbalances resulting from declining natural gas production and increased natural gas demand approach unsustainable levels. For areas that are pipeline constrained, high natural gas demand during extreme cold weather presents risks for generators that lack firm natural gas transportation arrangements.

Coal Transportation

While many factors that contributed to uncertain rail shipment of coal to electric generators prior to the 2022–2023 winter assessment have subsided, other transport issues could emerge for this winter. Drought conditions that impact the Missouri River and other major navigable waterways could restrict coal availability and cause units to run at a derated level to conserve coal inventory. Low water levels can also affect generators that rely on once-through cooling processes and limit the generator's capacity output.

Extreme Cold Temperatures and Demand Forecasting

Accurate load forecasting is essential for reliable operations. BAs and load-serving entities frequently update the load forecasts that serve as key inputs for long-range resource planning, seasonal outage coordination, and operational plans from day-ahead to real-time. Cold weather patterns and the temperature-correlated behavior of some end-use loads present some of the most challenging issues and complex load forecasting, adding to winter reliability risk.

Most assessment areas can experience a wide range of winter peak demand from one year to the next, largely depending upon the severity of winter conditions. Load forecasts for normal winter peak (referred to as 50/50 peak demand or net internal demand elsewhere in this report) reflect the highest expected system load for an average winter. A higher level of demand used throughout this report is the load forecast for extreme 90/10 peak demand, which generally represents the highest 10% of the winter peak demand forecast distribution.[4] Actual winter peak demand in each area is expected to be below this level most (but not all) years. Figure 3 shows these two demand levels for assessment areas where the extreme peak demand forecast is 9% or greater than the normal peak demand forecast. Year-to-year differences in winter weather conditions are key drivers of the large variation in normal and extreme demand forecasts, but changing load characteristics also contribute in many areas. ARMs, which measure resource levels above the normal 50/50 peak demand, have limited ability to identify resource adequacy risk when peak demand is highly variable from year to year.

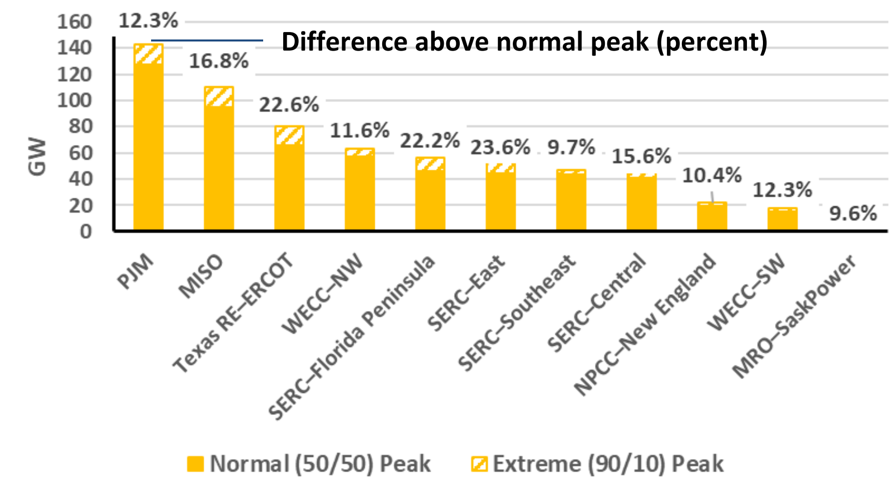


Figure 3: Normal and Extreme Peak Demand Forecasts for 2023–2024 Winter

The growing complexity in load forecasting and increasing load forecast uncertainty adds to winter reliability risks. Extreme cold temperatures and unfamiliar weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar PV DERs add to load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice, exposing BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme cold temperatures.

[4] Anticipated Reserve Margins (ARM) are calculated from this demand level. NERC assesses winter reliability risk using this extreme 90/10 peak demand level (see the risk scenario summary for each assessment area in the Regional Assessments Dashboards section).

Seasonal Risk Scenario Margins

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** section for more information about these charts.

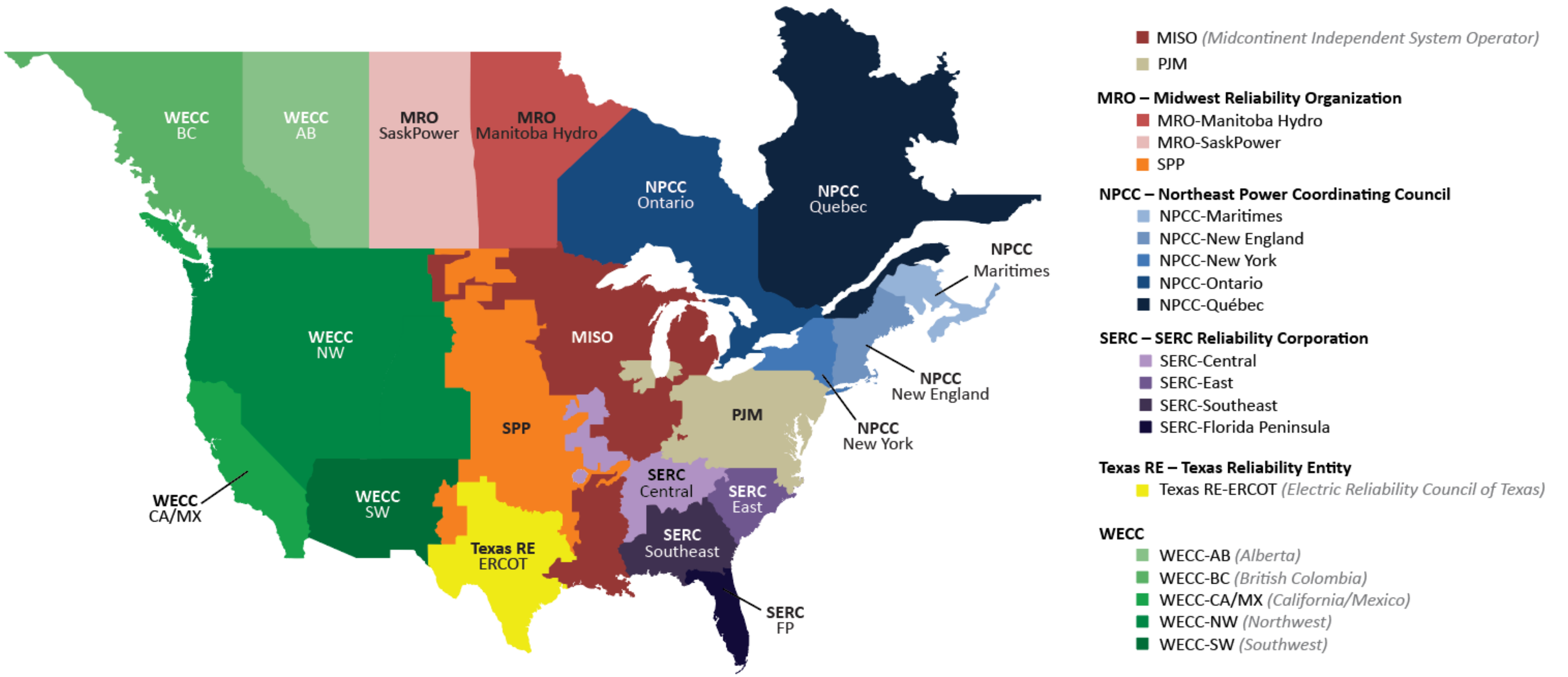
The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's ARM is shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 1: Seasonal Risk Scenario Margins

Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	55.8%	26.5%	-5.9%
MRO-Manitoba	15.3%	13.2%	6.6%
MRO-SaskPower	20.6%	6.9%	7.7%
NPCC-Maritimes	19.7%	13.5%	-0.5%
NPCC-New England	67.2%	47.3%	6.3%
NPCC-New York	76.3%	49.9%	12.4%
NPCC-Ontario	28.2%	28.2%	20.3%
NPCC-Quebec	10.5%	6.5%	-2.2%
PJM	39.8%	26.4%	4.2%
SERC-C	30.1%	22.6%	5.2%
SERC-E	24.4%	19.6%	9.3%
SERC-FP	41.0%	37.8%	12.7%
SERC-SE	41.6%	35.7%	13.7%
SPP	38.8%	14.5%	-14.1%
TRE-ERCOT	41.2%	27.3%	-6.6%
WECC-AB	27.1%	24.3%	5.5%
WECC-BC	15.1%	15.0%	-8.6%
WECC-CA/MX	65.3%	57.4%	32.2%
WECC-NW	43.5%	37.5%	-4.1%
WECC-SW	90.4%	85.1%	43.4%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the ARM compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.



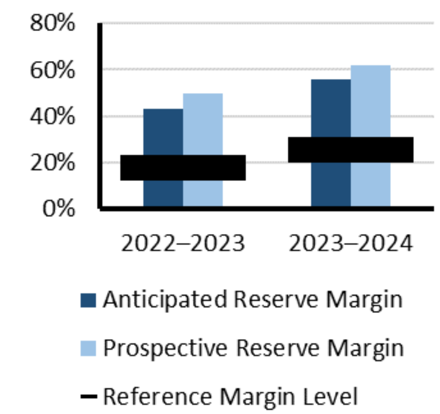
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 39 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Though some risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, reliability is expected to be maintained by the use of any number of measures, including load modifying resources, non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement for the winter but may still offer into the energy markets, or internal transfers that exceed the sub-regional import/export constraint between MISO North/Central and MISO South. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet any needs for firm or non-firm transfers to address extreme system conditions.
- The extreme cold weather of last winter is a reminder of just how critical resource adequacy and proper planning are for all seasons of the year, not just for a systems summer peak. Acknowledging this, MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO has filed and implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons. As a result, MISO has raised Reference Margin Levels for the 2023–2024 winter season. The 2023–2024 Planning Resource Auction conducted in April 2023 was the first implemented under the seasonal construct.

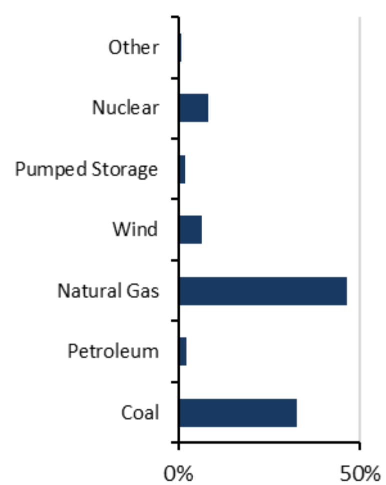
On-Peak Reserve Margin



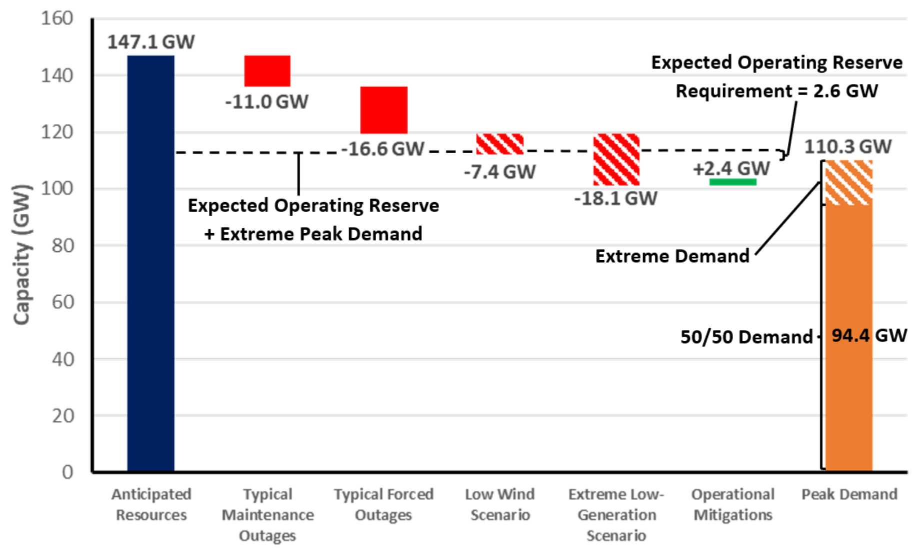
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEA). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year winter average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Low Wind Scenario: Below average wind contributions

Extreme Low-Generation: Maximum historical generation outages

Operational Mitigations: A total of 2.6 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas Manitoba Hydro provides electricity to approximately 608,500 electricity customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

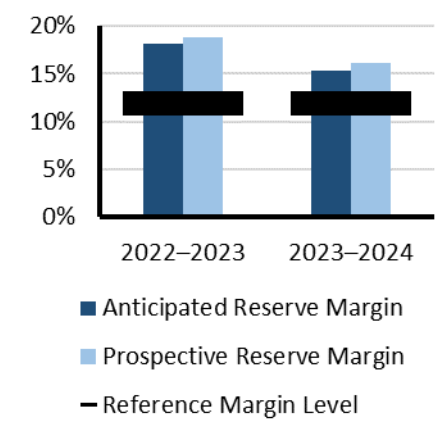
Highlights

- The ARM for winter 2023–2024 exceeds the 12% Reference Margin Level.
- No emerging reliability issues are anticipated for the upcoming winter season that are pertinent to Manitoba Hydro.
- Manitoba Hydro continues to monitor a number of issues, including extreme weather events like drought, decarbonization-driven changes to supply and demand, and asset health.
- All seven units at the Keeyask hydro station (630 MW net addition) are anticipated to be in commercial operation for winter 2023–2024.

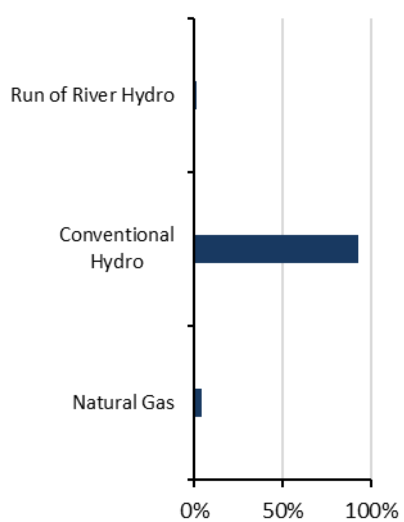
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

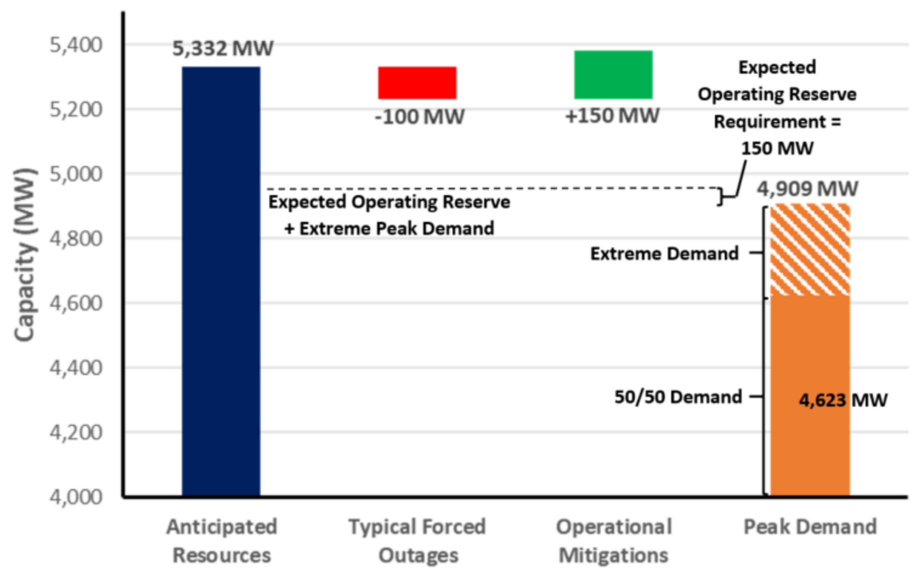
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand scales additional load experienced during all-time peak actual versus forecasted load (January 2019)

Forced Outages: Accounts for average forced outages

Operational Mitigations: Emergency Operating Procedures

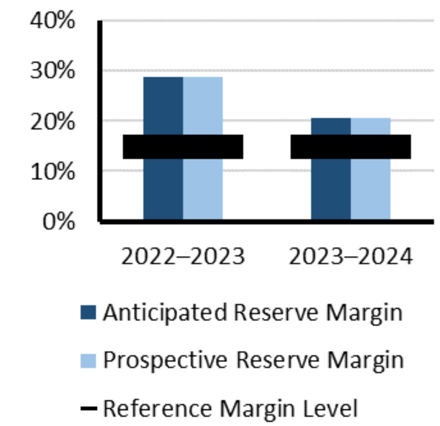
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.2 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

- Saskatchewan experiences peak load in winter because of extreme cold weather. Reserve margins have fallen this winter by about 8% when compared to the previous winter due to increased peak demand projections, the retirement of a natural gas unit (95 MW), and an increase of planned maintenance.
- The risk of operating reserve shortage or EEA during peak load times exists if a large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months.
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.

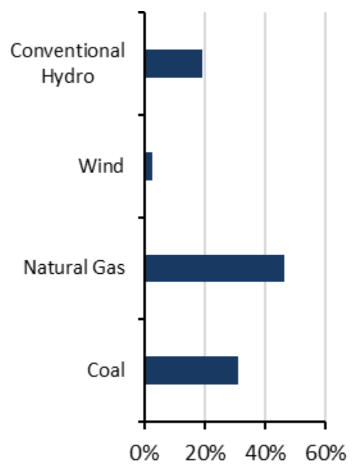
On-Peak Reserve Margin



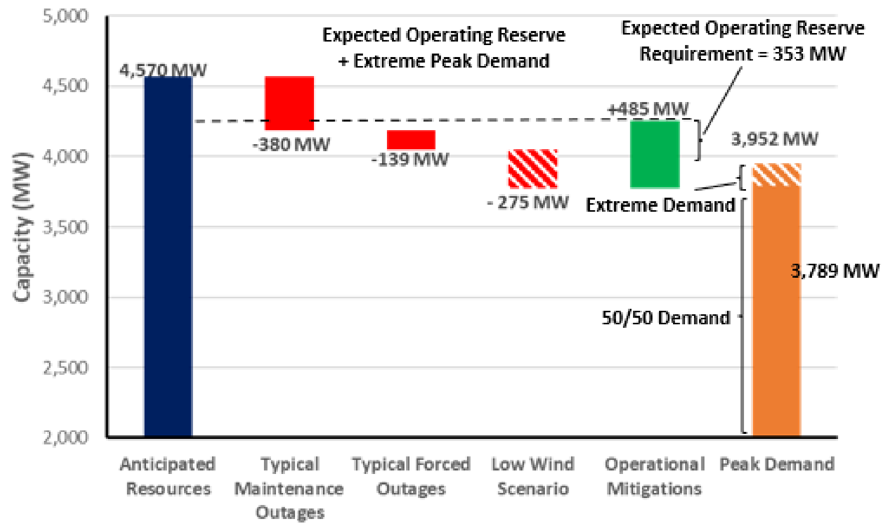
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. The risk of load shedding is low.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on potential system peak load increased by average forecast error of previous five years

Maintenance Outages: Average of planned maintenance outages for the winter months, December–February, over the past three years

Forced Outages: Estimated using SaskPower forced outage model

Low Wind Scenario: Estimated using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short term transfer capability from neighboring utilities (150 MW) and reserved generating units (135 MW) for the upcoming 2023–2024 winter. This also includes 200 MW in demand-side resources and non-firm loads that require 15 minutes to 2 hours of advanced notification.

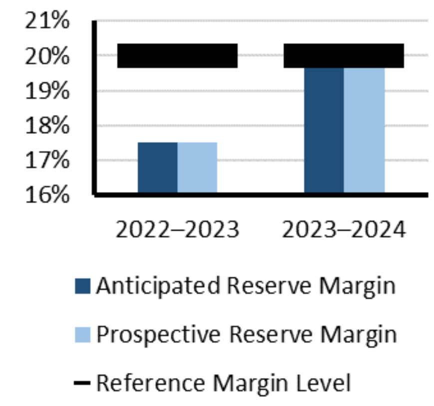
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the winter operating period.
- The Maritimes area is a winter-peaking system.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.

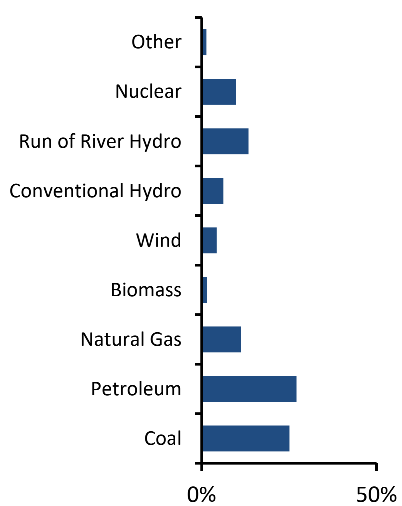
On-Peak Reserve Margin



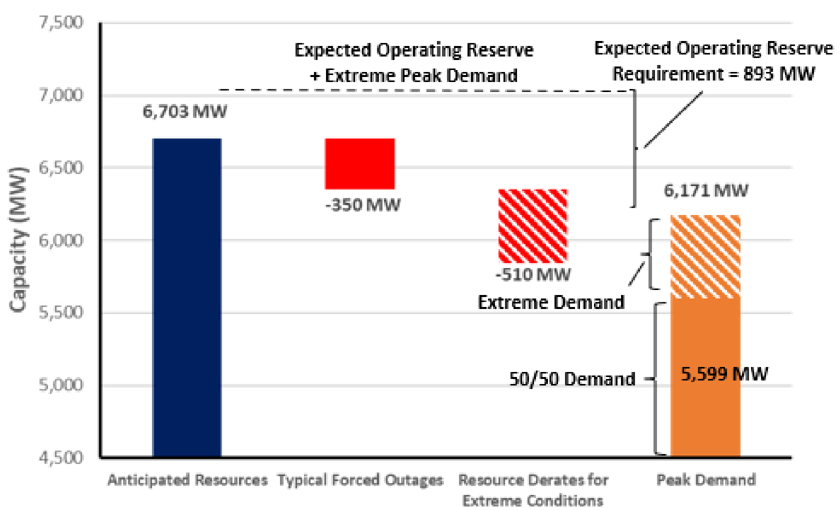
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See **Probabilistic Assessment** section.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 20 years of historical data

Forced Outages: Based on historical operating experience

Extreme Derates: A low likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

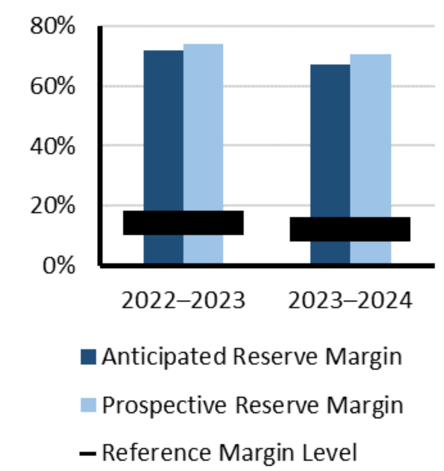
NPCC-New England

NPCC-New England is an assessment area that is served by ISO-NE, and it consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2023–2024 winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold period given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquified natural gas).
- ISO-NE is offering an interim program to compensate certain resources that provide fuel security. The Inventoried Energy Program is a voluntary, interim program designed to provide incremental compensation for participants that maintain inventoried energy for their assets during extreme cold periods when winter energy security is most stressed.
- ISO-NE expects to have sufficient capacity resources to meet the 2023–2024 90/10 winter peak demand forecast of 21,032 MW for the weeks beginning January 7, January 14, and January 21, 2024.
- ISO-NE evaluates an above 90/10 scenario, which captures the area's coldest day in the last 25 years while using both their current and future load models. The above 90/10 winter peak demand forecast is 21,746 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand however if a cold snap were to occur the area may have to rely on its external ties and emergency procedures to operate reliably.

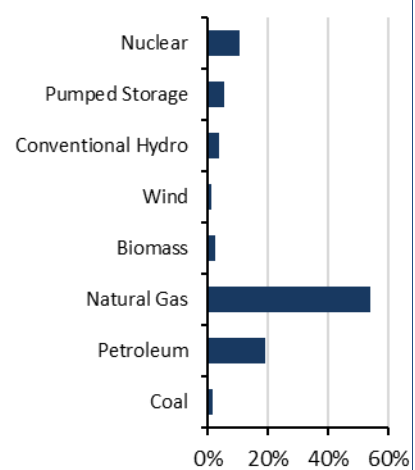
On-Peak Reserve Margin



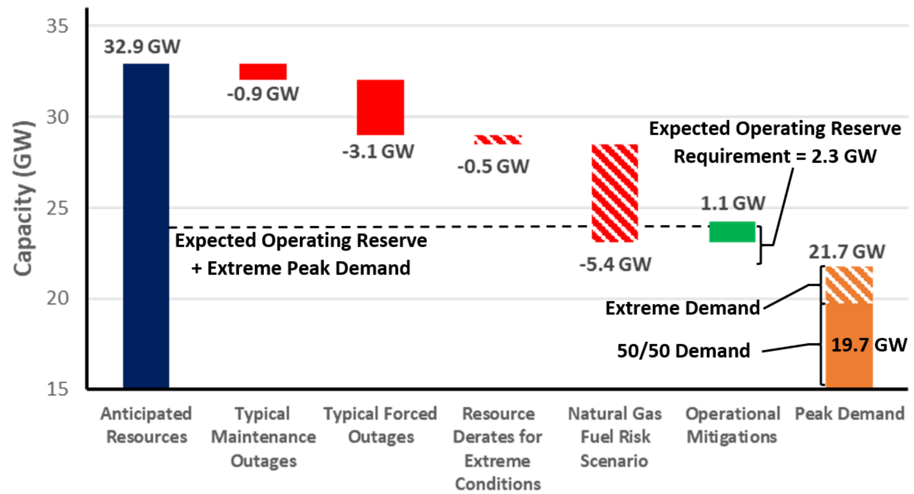
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area prolonged cold weather events. See **Probabilistic Assessment** section.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast for coldest day from the last 25 years

Maintenance and Forced Outages: Based on weekly averages

Extreme Derates and Natural Gas Scenario: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages reported by generators

Operational Mitigations: Based on ISO-NE operating procedures

NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this WRA, the established Reference Margin Level is 15%; wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2023–2024 IRM at 20.0%.

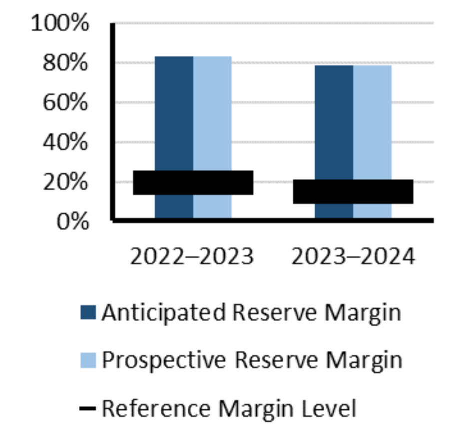
Highlights

- New York is a summer-peaking area, and no emerging reliability issues are anticipated during the 2023–2024 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.

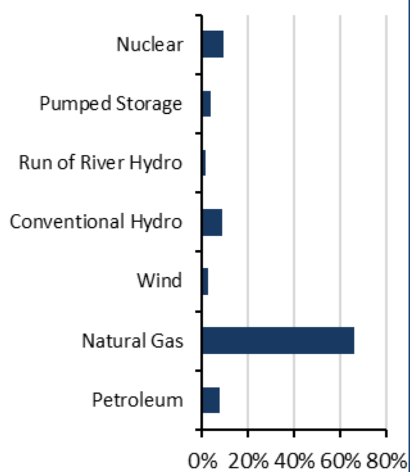
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

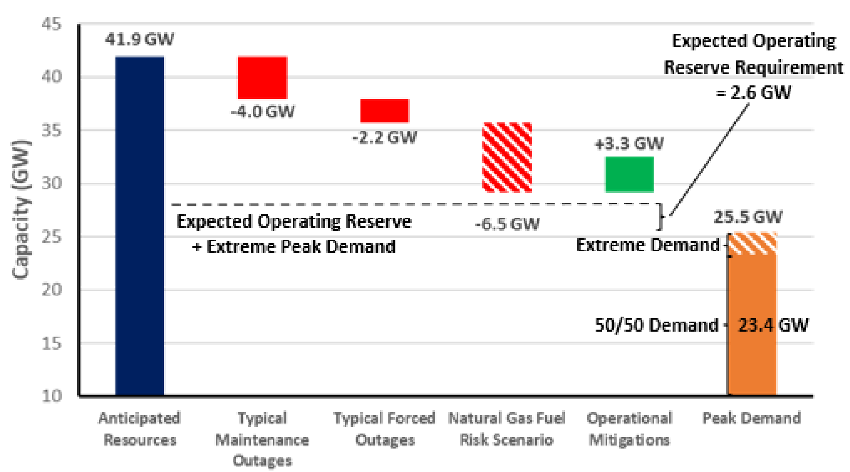
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Based on planned scheduled maintenance

Forced Outages: Five-year average of all outages that were not planned

Natural Gas Fuel Scenario: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather

Operational Mitigations: Based on NYISO operating procedures

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

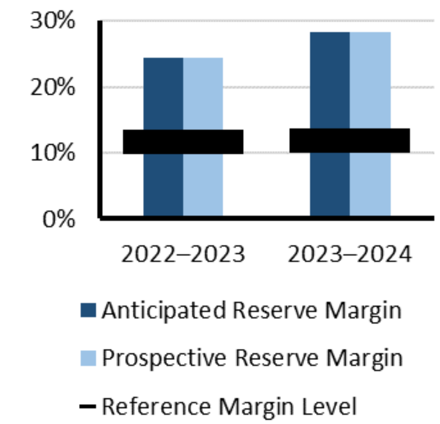
Highlights

- IESO anticipates that it will maintain reliability on its system through the winter of 2023–2024.
- Reference margins are forecast to remain at adequate levels in both normal and extreme weather scenarios.
- Ontario regularly experiences extreme cold weather; its generation fleet, transmission system, and fuel delivery infrastructure are well prepared for and adapted to such conditions.
- Unit 3 at the Darlington Nuclear Generating Station was reconnected to the provincial grid following refurbishment in July 2023, nearly six months ahead of schedule. Bruce Nuclear Generating Station's Unit 6 was returned to service following a successful refurbishment that began in January 2020.
- The IESO's December 2022 Annual Capacity Auction secured 1,160 MW of capacity for winter 2023–2024.

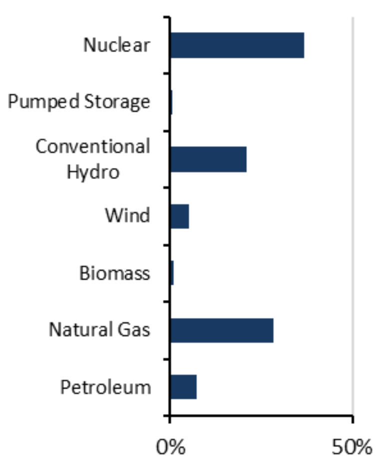
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

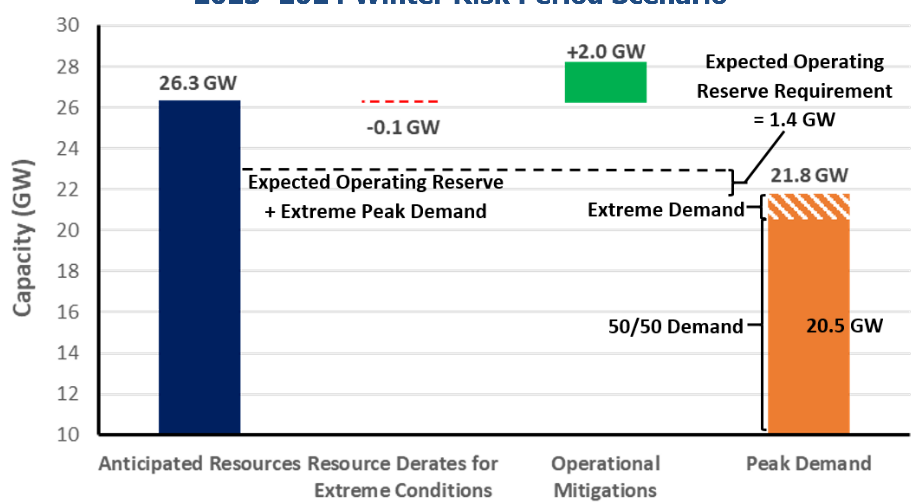
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Extreme Derates: Generation unavailability in an extreme event using temperature derates

Operational Mitigations: Imports anticipated from neighbors during emergencies

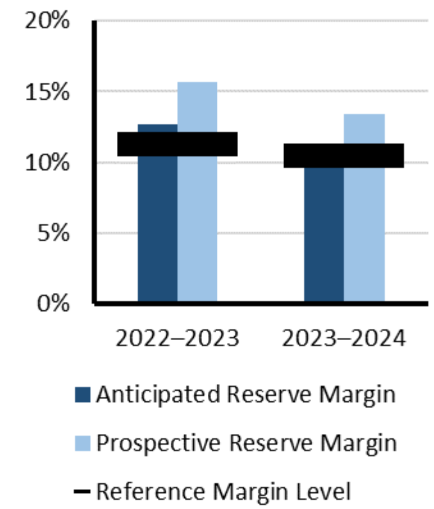
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America, and it has ties to Ontario, New York, New England, and the Maritimes that consist of either high voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- Québec predicts that it will maintain system resource adequacy this winter.
- Forecasted demand increase and additional firm export commitments have resulted in shrinking reserve margins.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2023–2024 winter assessment period.
- No changes have been made to the assessment area's winter preparedness programs.

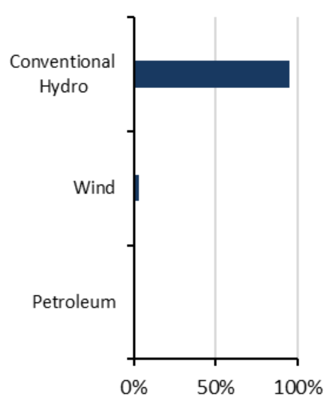
On-Peak Reserve Margin



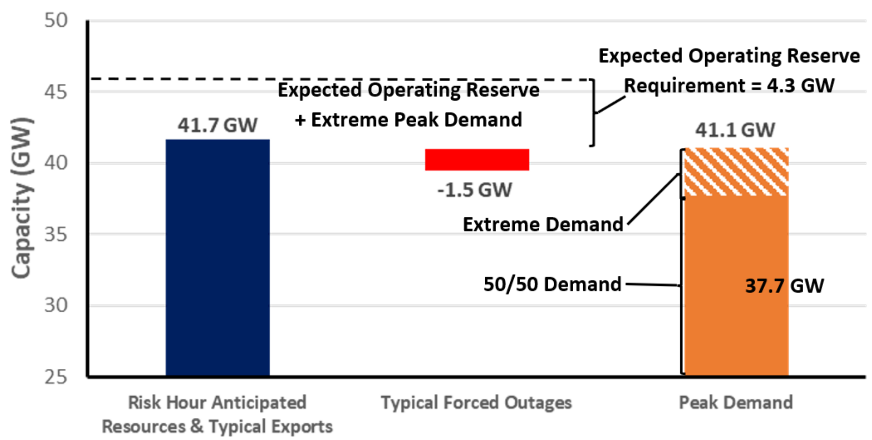
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See the Probabilistic Assessment section.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Net internal demand (50/50) and (95/5) demand forecast

Forced Outages: Rare scenario of 1,500 MW in unplanned outages

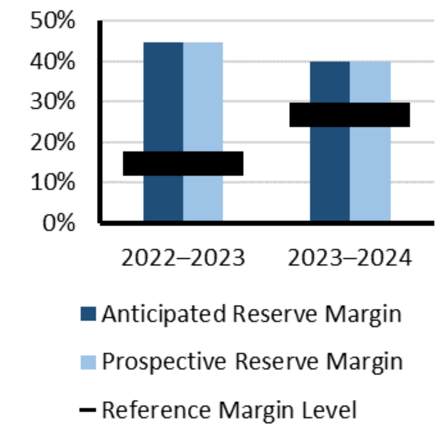
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- Installed capacity is significantly higher (13 percentage points) than PJM's Reserve Requirements. PJM does not expect to encounter resource problems for anticipated conditions over the 2023–2024 winter Peak season.
- A severe cold weather event that extends to the South can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have decreased since 2022 when Winter Storm Elliot caused energy emergencies in PJM and surrounding areas.

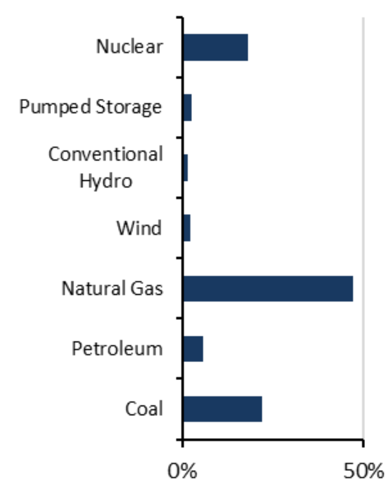
On-Peak Reserve Margin



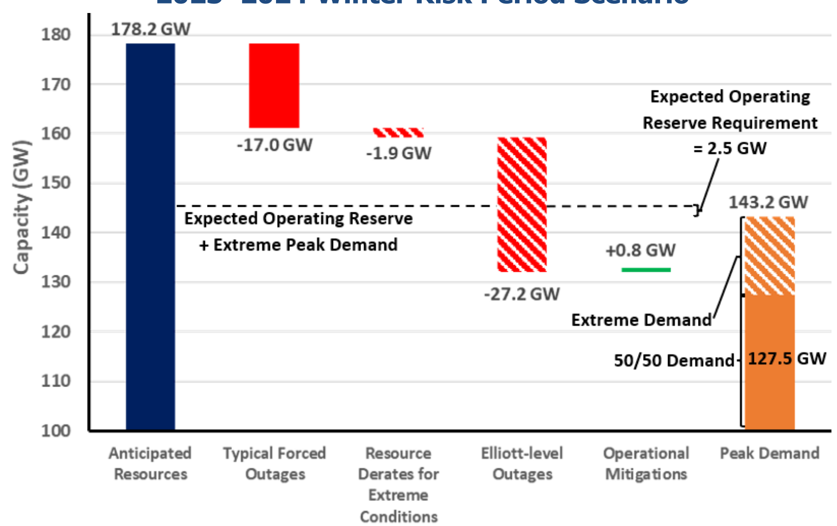
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed normal and extreme scenarios. Generator outages on a level of those experienced during Winter Storm Elliot would lead to energy emergencies.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Elliott-level Outages: Additional forced outages equal to the total MW capacity on outage due to freezing and fuel issues during winter storm Elliott in 2022.

Operational Mitigations: A total of 0.8 GW based on operational/emergency procedures

* See PJM Report *Winter Storm Elliott Event Analysis and Recommendations Report*, July 17, 2023, available here.

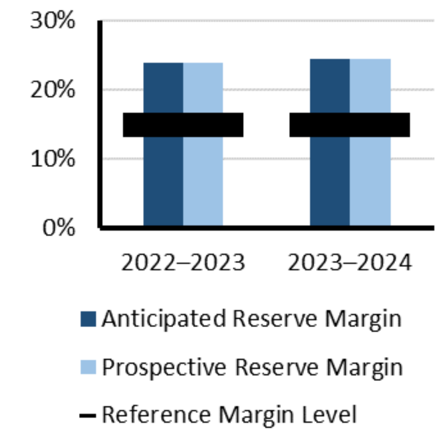
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC East assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.

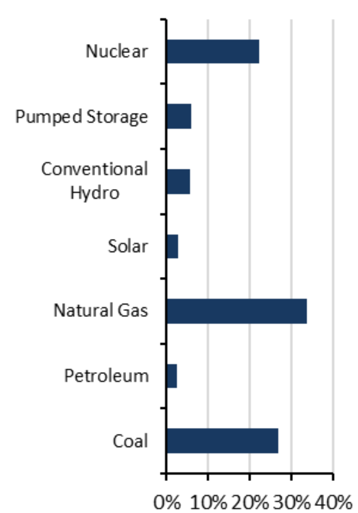
On-Peak Reserve Margin



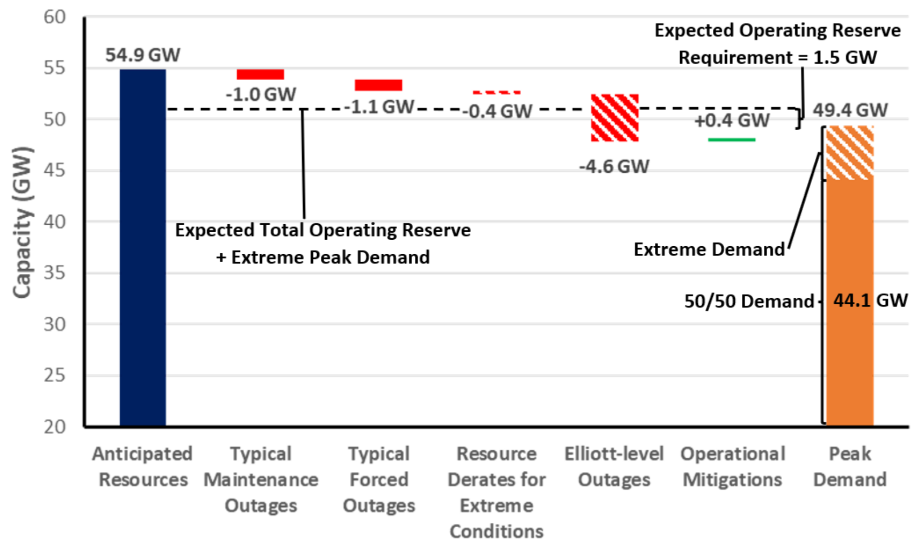
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages (excluding 2022-2023)

Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022

Operational Mitigations: A total of 0.4 GW based on operational/emergency procedures

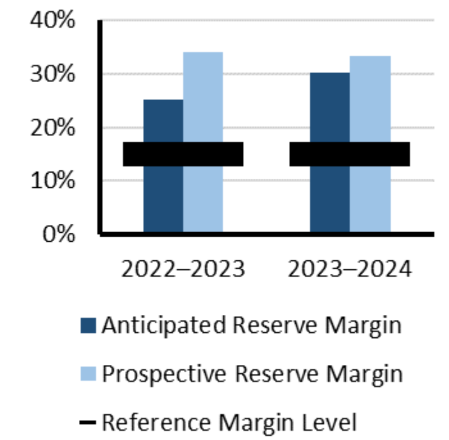
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Central assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- While short-term issues (e.g., forced outages, colder than normal temperatures, or supply issues) around neighboring systems or natural gas pipelines are possibilities, the SERC-Central assessment area expects to maintain real-time operating reserves at all times. Therefore, SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Central has extensive weatherization processes that include developed procedures specific to freezing events. SERC-Central is prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.

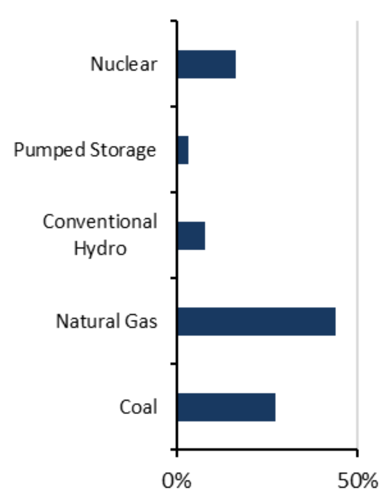
On-Peak Reserve Margin



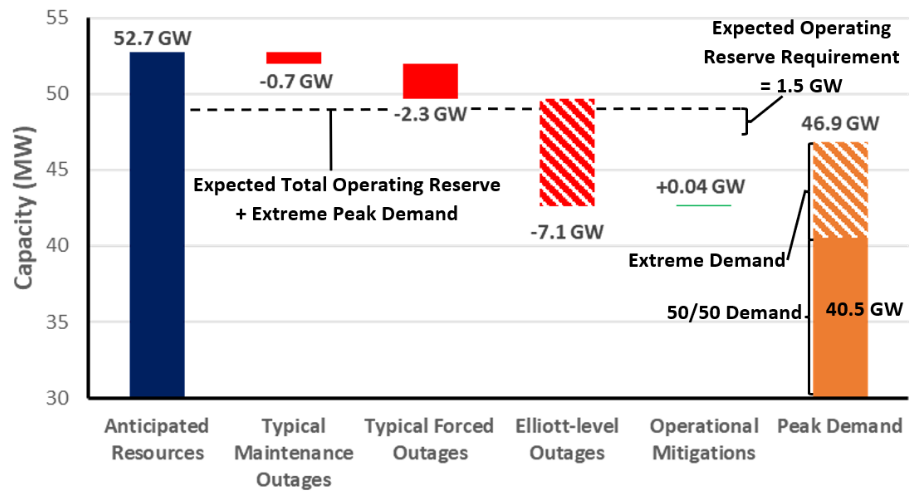
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. A severe cold weather event that extends to the South could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Includes any weighted average forced outage rates on-peak that are not factored into the anticipated resources calculation

Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022

Operational Mitigations: A total of 0.04 GW based on operational/emergency procedures

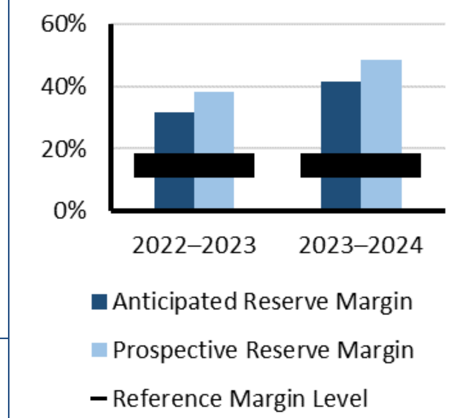
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Southeast assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unexpected, day-to-day events and coordinate with neighboring entities to promote overall system reliability.

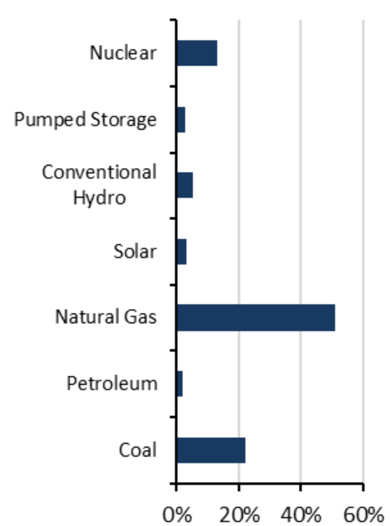
On-Peak Reserve Margin



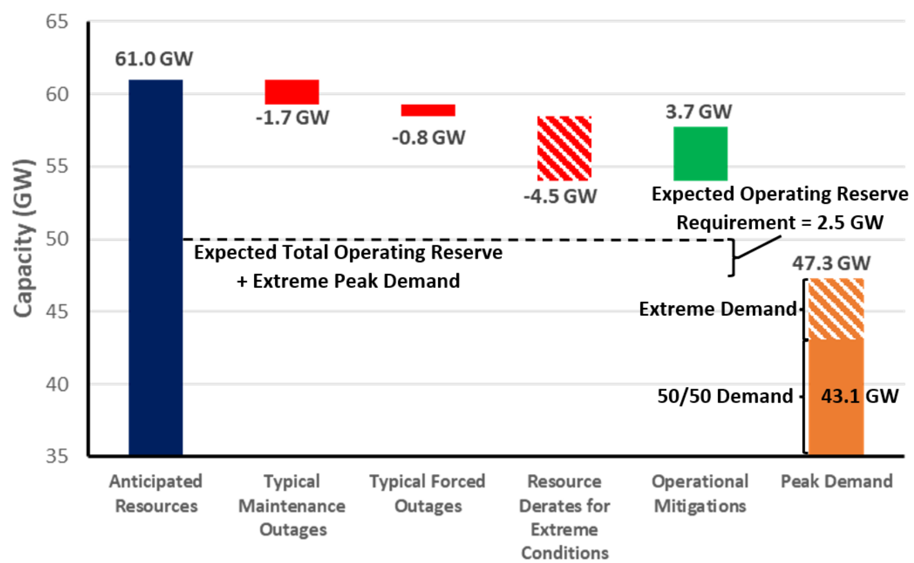
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 3.7 GW based on operational/emergency procedures

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

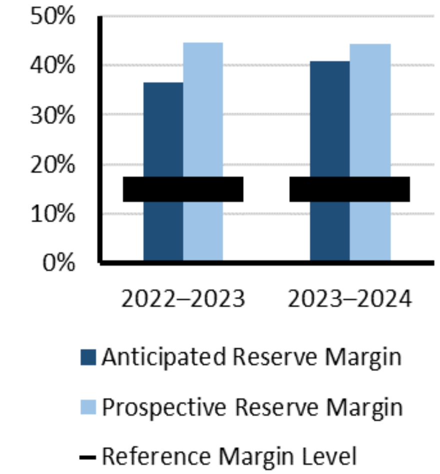
Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC Florida-Peninsula assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- Although the entities do not currently anticipate reliability impacts in the upcoming winter season, some entities have expressed concerns about the difficulty of scheduling and receiving coal deliveries on a consistent basis, which would affect unit availability.
- The entities have performed a summary review of their winterization plans as well as the coordination of generation and transmission outages through the Florida Reliability Coordinating Council (FRCC) Operations PC and RC functions.

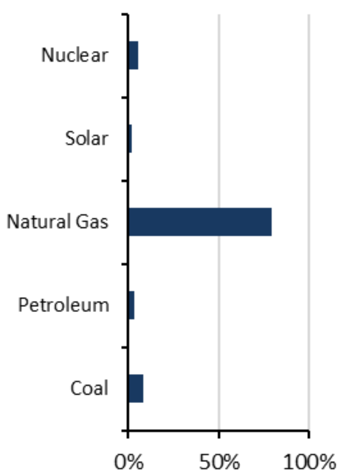
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

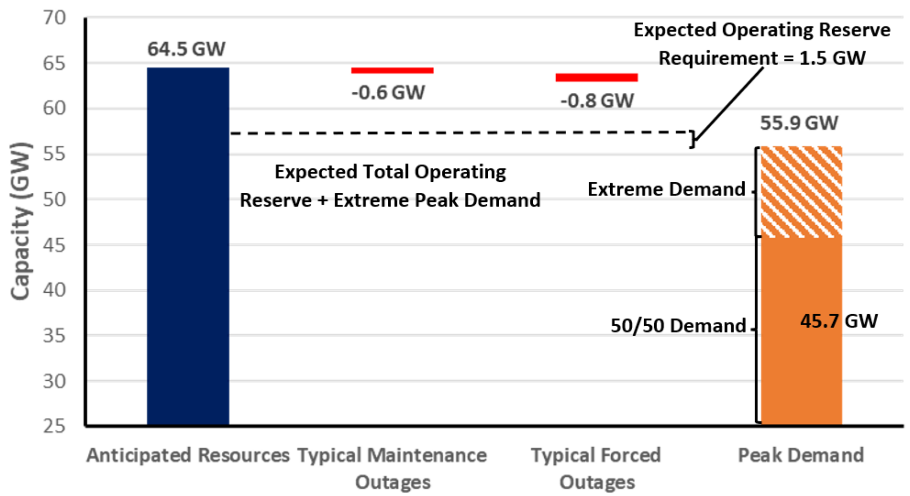
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

SPP

SPP PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and serves a population of more than 18 million.

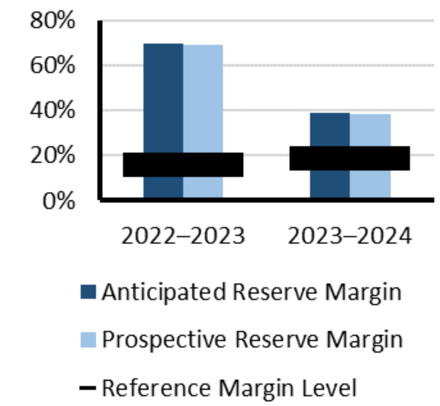
Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season. Reserve margins have fallen this winter because of increased peak demand projections and declining anticipated resources.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2023–2024 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues to work with neighboring areas to address potential electricity deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness.
- To minimize conservative operations, EEAs, and the response to mid-range forecast error uncertainty in wind forecasts, SPP created some new mitigation processes to deal with high-impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real-time reliability needs.
- SPP created a Resource and Energy Adequacy Leadership Team that is addressing numerous resource adequacy initiatives that are addressing an expected unserved energy (EUE) standard, fuel assurance, winter requirements, winter PRM, outage policies, demand response, accreditation, and other areas of impact.
- SPP hosted its winter preparedness workshop in October 2023.

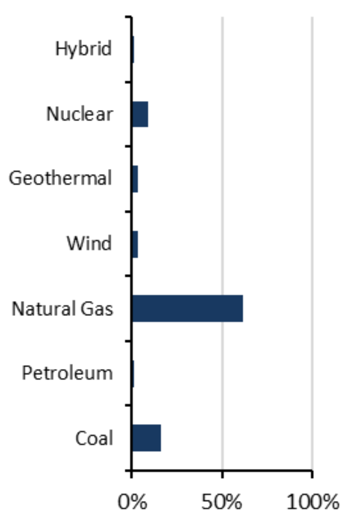
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

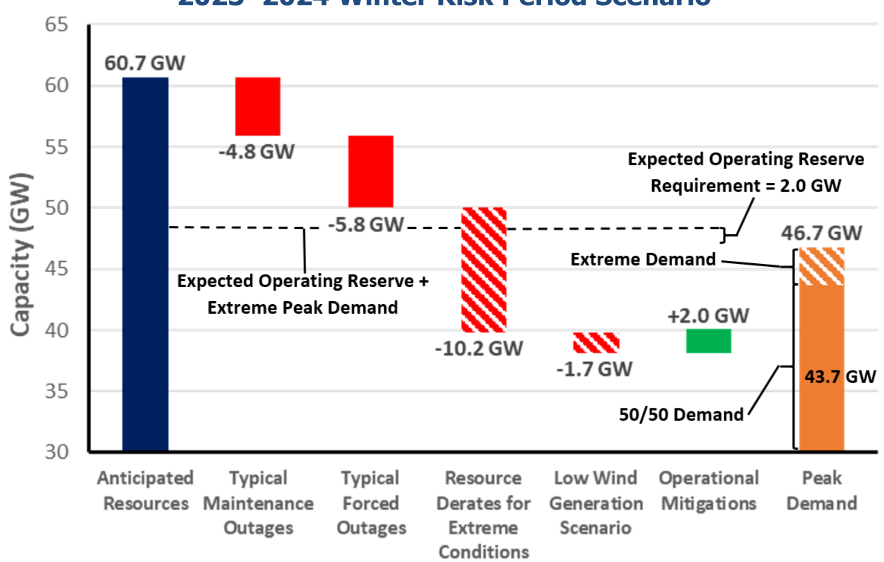
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

Extreme Derates: A capacity derate for generator performance in extreme weather based on historical data

Low Wind Scenario: 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)

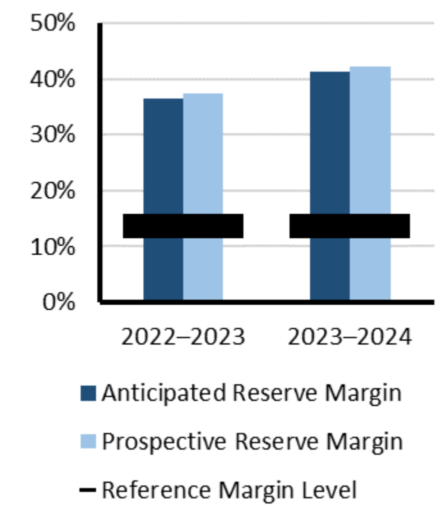
Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

Highlights

- For the upcoming winter season, Texas RE-ERCOT will face reserve shortage risks during high net load hours. In winter, solar generation is not available to serve peak demand, making the system dependent on wind generation and dispatchable resource availability to serve load.
- Reserve scarcity risks are greater than last winter due primarily to robust load growth along with insufficient new dispatchable resources to serve the higher net peak loads.
- The area has also experienced a large increase in thermal units planned to be indefinitely mothballed to operate under a summer-only availability schedule; a loss of 1,283 MW of winter-rated capacity is expected.
- The risk of reserve shortages leading to EEA declarations has increased from “low” to “elevated” for hour-ending 8:00 a.m. based on ERCOT’s probabilistic risk assessment. ERCOT is investigating the option to procure additional capacity to reduce this reserve shortage risk on a competitive basis.
- ERCOT does not expect any significant fuel supply issues for the winter. However, fuel-related outages during Winter Storm Elliott (December 22–25, 2023) indicated that natural gas-fired generators that normally experience fuel restrictions during cold weather are expected to continue to face such restrictions. ERCOT’s new Firm Fuel Supply Service was deployed during this storm and is expected to partially offset the lost generation capacity due to these natural gas restrictions.
- ERCOT has observed increasing transmission congestion from South Texas to South-Central Texas (including the San Antonio area) that will limit transfers during the winter. A transmission project that includes a new 345 kV double circuit transmission line was recommended with an expected in-service date of June 2027 to address this congestion.

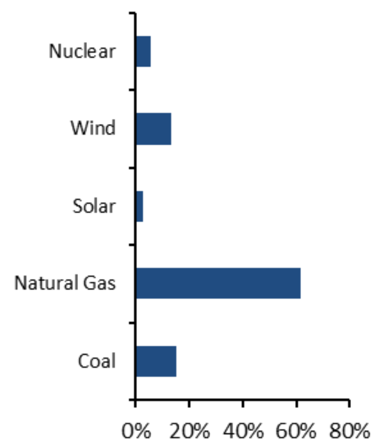
On-Peak Reserve Margin



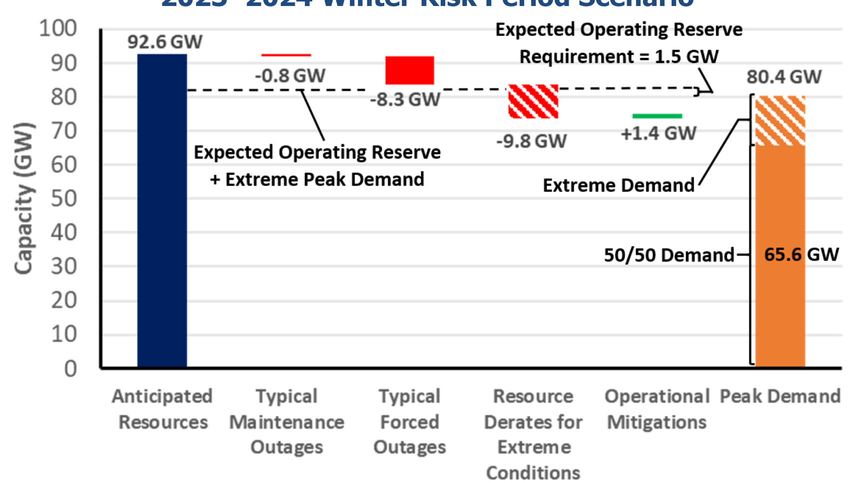
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 Winter Storm Uri peak demand

Maintenance Outages: Based on historical winter data and consideration of ERCOT’s allowed maximum system daily planned outage capacity

Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2020/2021, 2021/2022, and 2022/2023) winter seasons (Winter Storm Uri-related forced outages between February 15–18, 2021, were excluded from this calculation.)

Extreme Derates: Accounts for reduced thermal, wind, and solar PV capacity contributions due to performance in extreme conditions (uses averages from Winter Storm URI with adjustments to account for implemented weatherization improvements)

Operational Mitigations: Additional potential capacity from switchable generation and imports

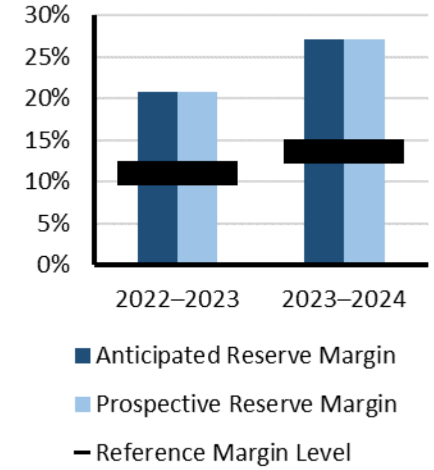
WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western U.S. states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Alberta shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports if not islanded.
- WECC- Alberta's operating reserve margins are met before imports in all scenarios except the Low Wind Scenario, which leaves a gap of 0.5 GW, and the Extreme Combined Scenario, which leaves a gap of 1.0 GW under extreme peak demand conditions. Both of these scenarios are anticipated to be able to be covered through imports. WECC-Alberta is a winter-peaking area and did see a few EEA-3s last season due to a combination of extreme demand peaks from cold temperatures, low wind, and the loss of a baseload unit.

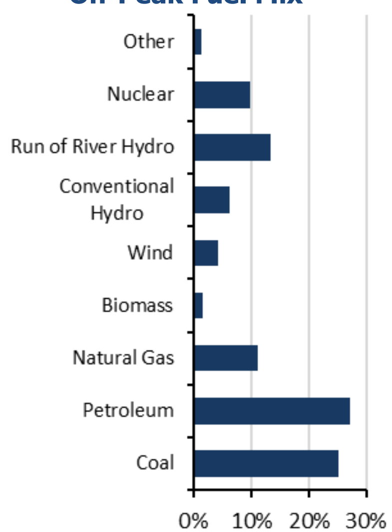
On-Peak Reserve Margin



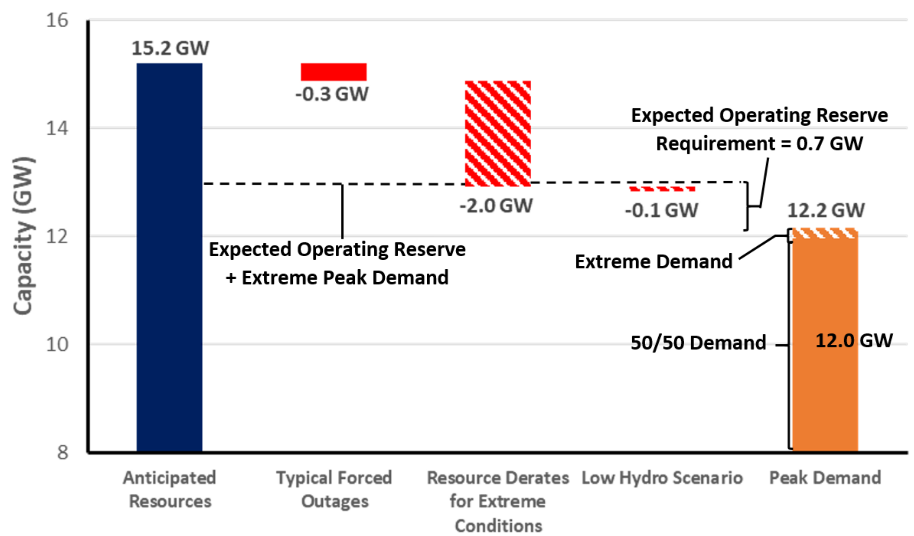
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

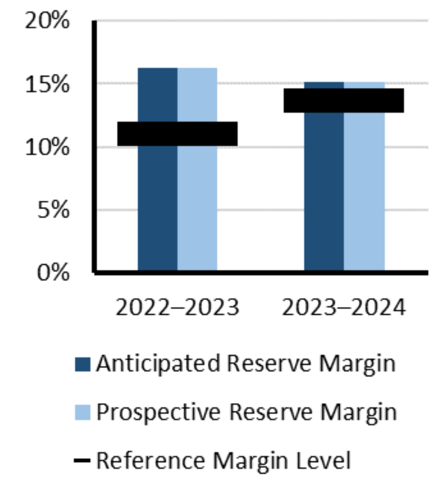
WECC-British Columbia

WECC-British Columbia is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-British Columbia has adequate resources for anticipated winter conditions. If peak demand exceeds normal forecasts or hydroelectric generation is lower than normal, non-firm imports may be needed to meet required operating reserves.
- WECC-British Columbia could require a range of import levels for extreme demand or low-resource scenarios. For expected demand, the area falls short of its operating reserve requirements if hydro output is abnormally low (low likelihood scenario). During the Extreme Peak Demand Scenario (90th percentile), operating reserve margins fall short by 0.6 GW with anticipated resources and could increase for more extreme outages or low-hydro scenarios. Sufficient imports from neighbors in the Western Interconnection are expected to be available, provided that BC does not become electrically islanded.

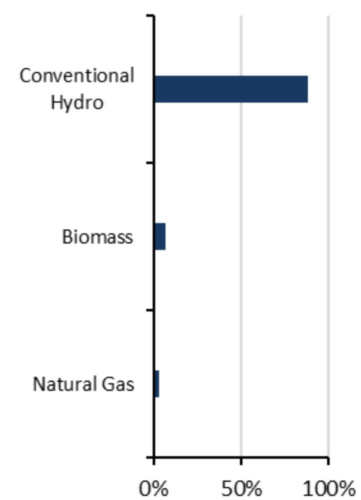
On-Peak Reserve Margin



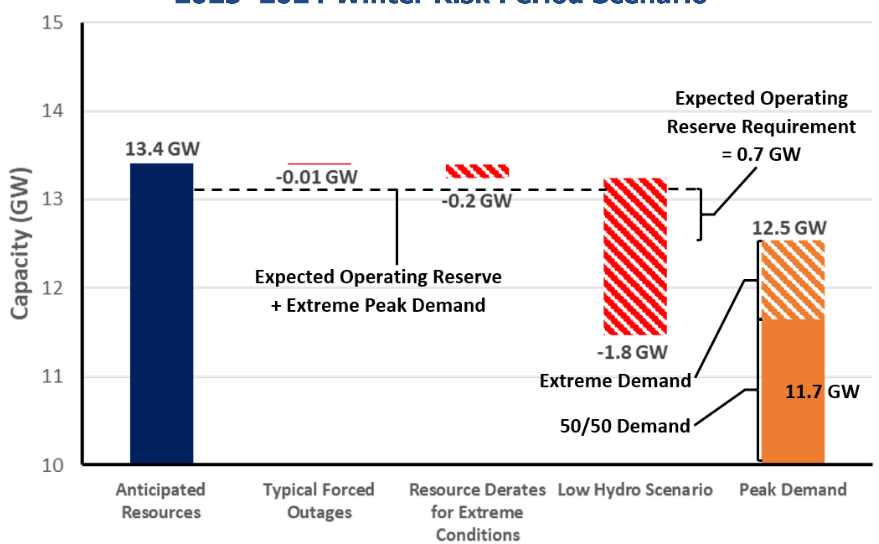
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

WECC-California/Mexico

WECC-Californica/Mexico is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

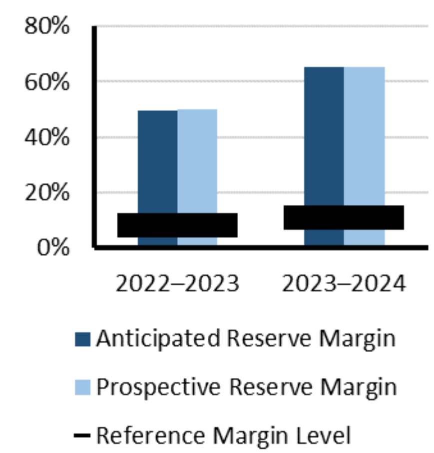
Highlights

- WECC-Californica/Mexico shows adequate energy availability under both expected and extreme scenarios.

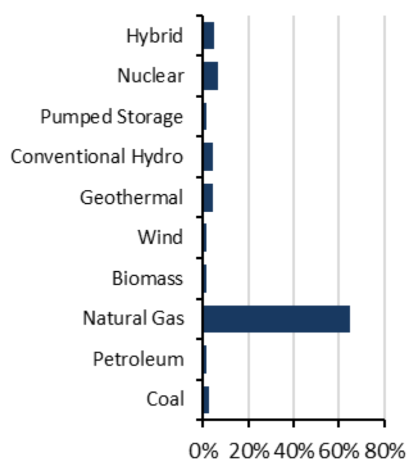
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

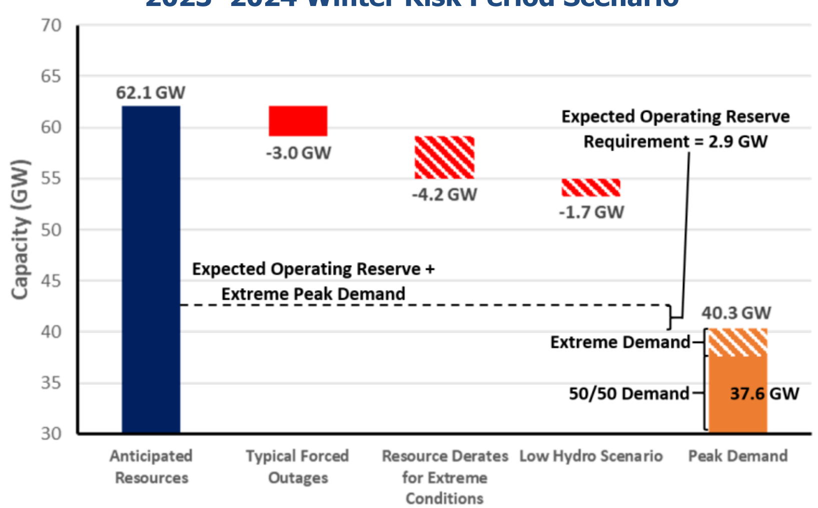
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

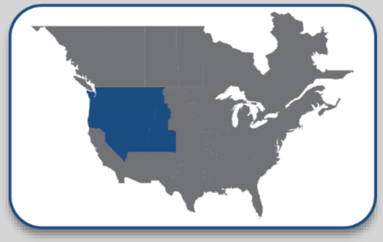
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-Northwest

WECC-Northwest is a summer-peaking assessment area in the WECC Regional Entity that includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

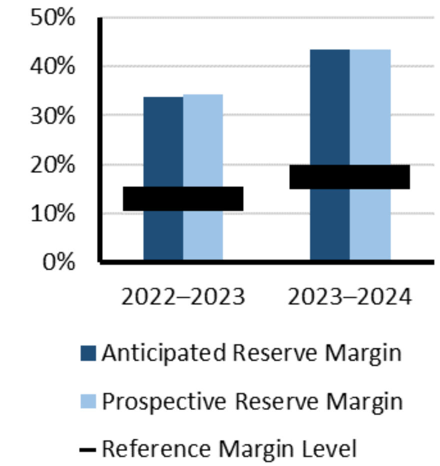
Highlights

- WECC-Northwest shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports.
- WECC-Northwest has historically been a mixed-season peaking area. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined Scenario, where 5.3 GW of imports would be needed to meet operating reserve margins at an expected peak demand (50th percentile) and 10 GW for an extreme peak load level (90th percentile). Depending on the situation in neighboring areas, imports are expected to be available to fill the gap.

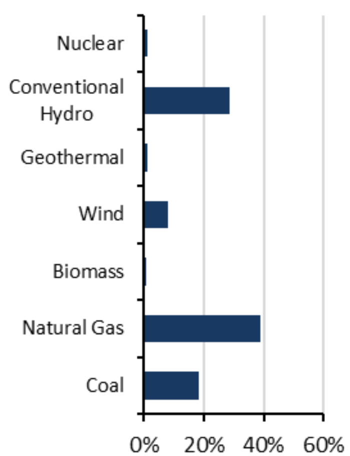
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

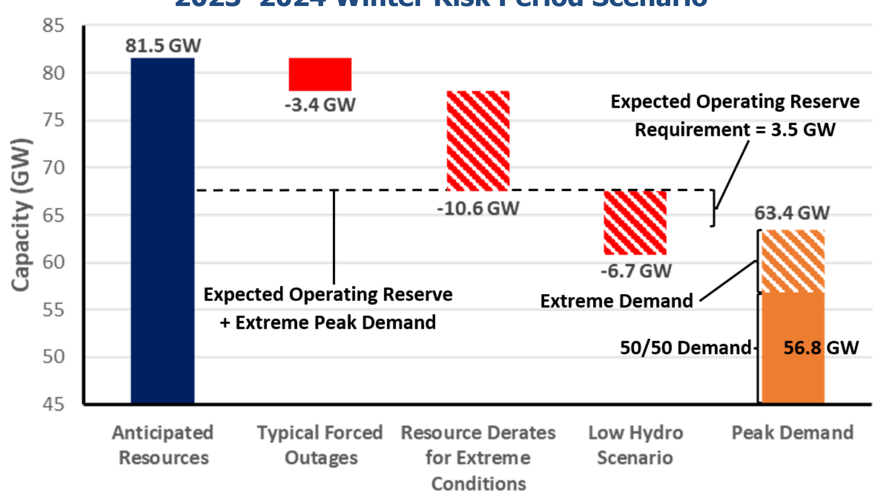
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

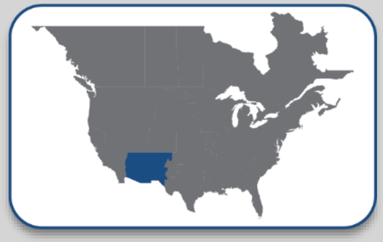
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



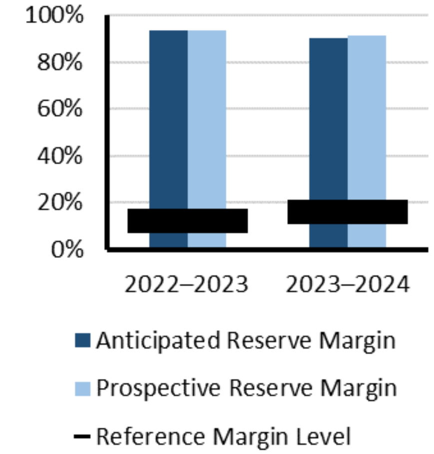
WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the WECC Regional Entity that includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Southwest shows adequate energy availability under both expected and extreme scenarios.

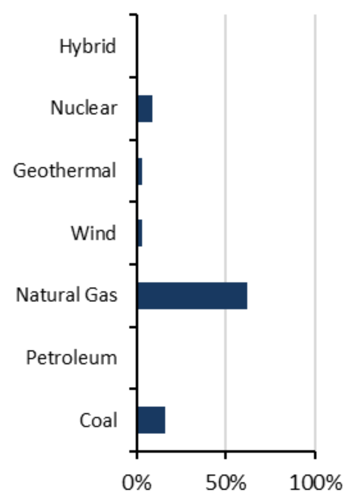
On-Peak Reserve Margin



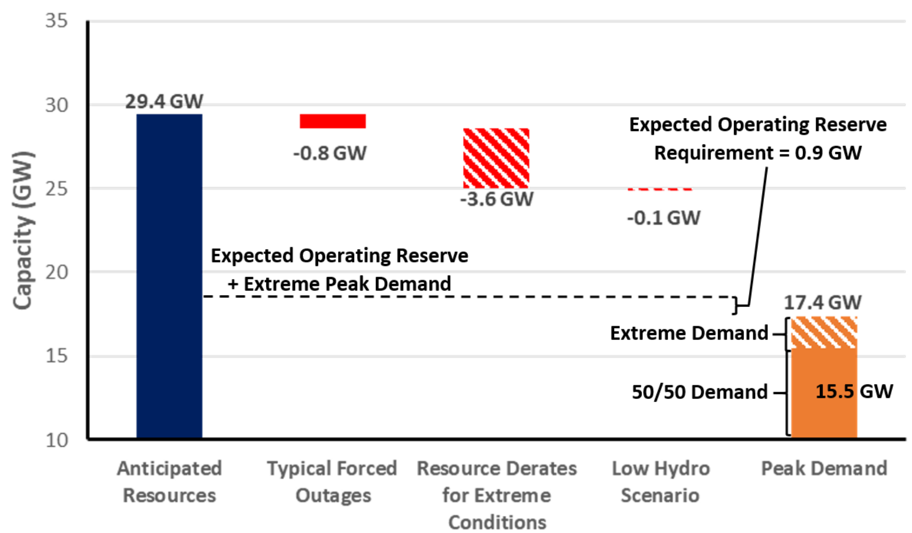
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• The reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2023 Long-Term Reliability Assessment* data has been used for most of this 2023–2024 assessment period augmented by updated load and capacity data provided by Regional Entities and assessment areas.
• A positive net transfer capability would indicate a net-importing assessment area, a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[5] or total internal demand for the summer and winter of each year.[6]
• Total internal demand projections are based on normal weather (50/50 distribution[7]) and are provided on a coincident[8] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[5] *Glossary of Terms* used in NERC Reliability Standards

[6] The summer season represents June–September and the winter season represents December–February.

[7] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[8] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: This includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme winter peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[9] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet their RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their Reference Margin Level for the 2023 winter as shown in **Figure 4**.

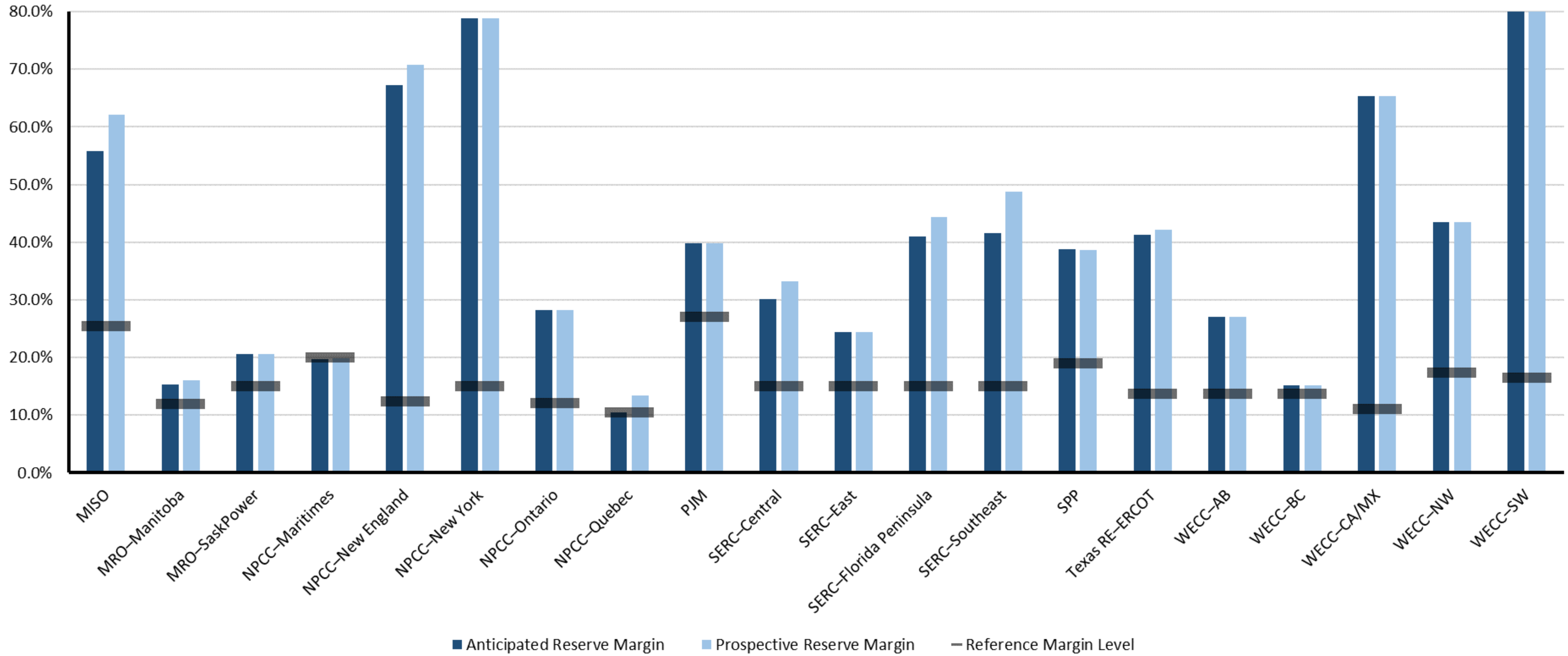
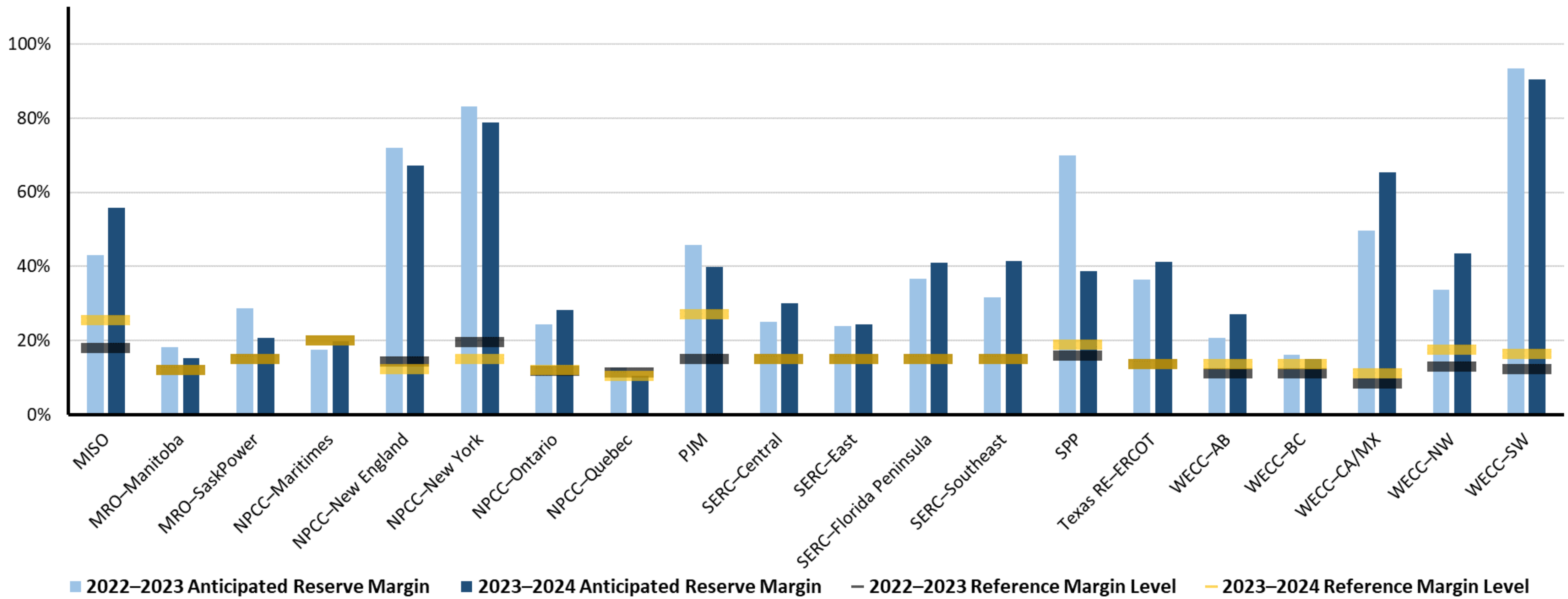


Figure 4: Winter 2023–2024 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[9] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins (ARM) from the 2022–2023 winter to the 2023–2024 winter. Note that the Reference Margin Level is unchanged for areas that don't have a 2022–2023 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC have noticeable reductions in anticipated resources between the 2022–2023 winter and the 2023–2024 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2023–2024 winter. NPCC-Québec is marginally above its Reference Margin Level. The lower ARMs for MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC do not result in reliability concerns during expected conditions for this upcoming winter. The Canadian winter-peaking systems of MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the **Data Concepts and Assumptions** section.



Note: The areas that only have one bar have the same Reference Margin Level for both

Figure 5: Winter 2022–2023 and Winter 2023–2024 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 6**.[10] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections. Most assessment areas are showing increasing demand for the upcoming winter compared with the last WRA.

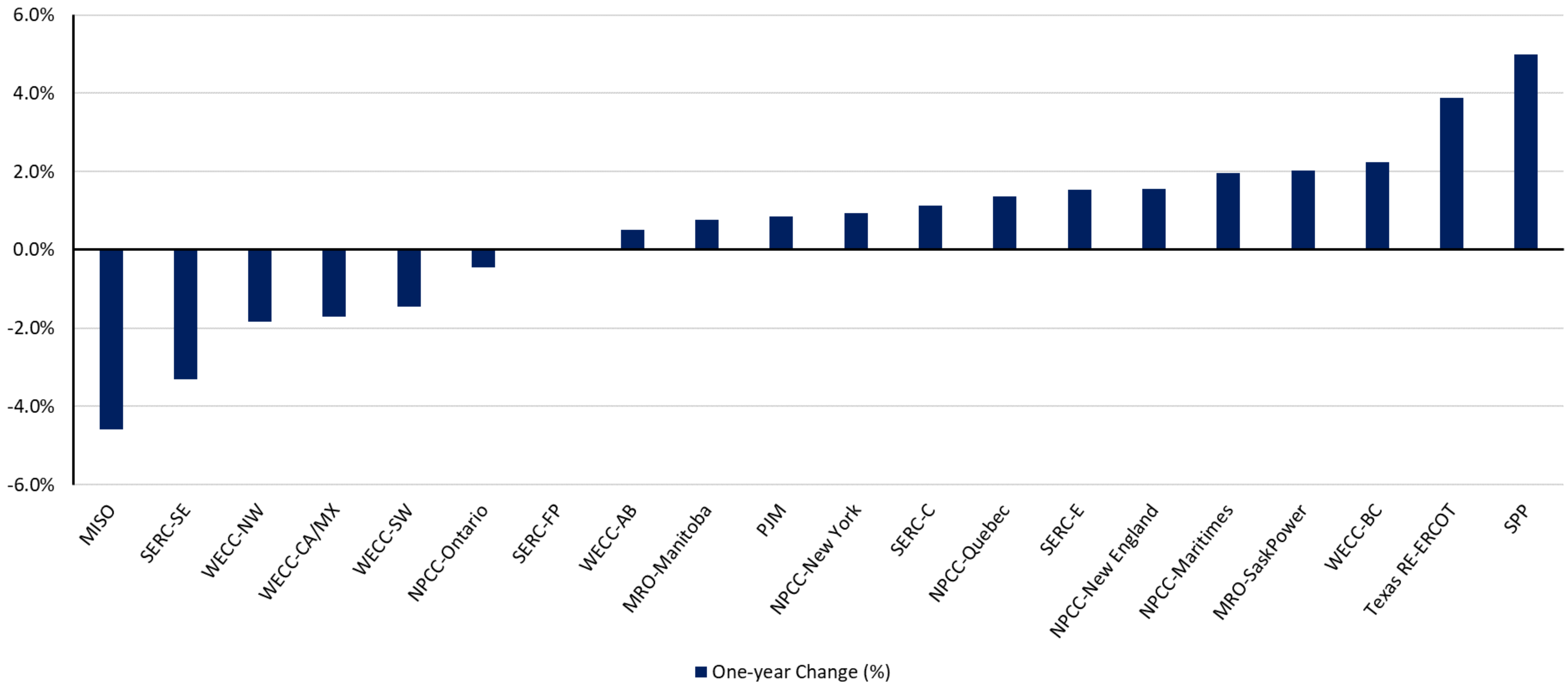


Figure 6: Change in Net Internal Demand—Winter 2022–2023 Forecast Compared to Winter 2023–2024 Forecast

[10] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,611	102,075	0.5%
Demand Response: Available	3,672	7,681	109.2%
Net Internal Demand	98,939	94,394	-4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	137,926	146,976	6.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,352	121	91.1%
Anticipated Resources	141,565	147,097	3.9%
Existing-Other Capacity	669	2,614	290.8%
Prospective Resources	148,125	153,003	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.1%	55.8%	12.7
Prospective Reserve Margin	49.7%	62.1%	12.4
Reference Margin Level	17.9%	25.5%	7.6

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,588	4,623	0.8%
Demand Response: Available	0	0	-
Net Internal Demand	4,588	4,623	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,705	5,864	2.8%
Tier 1 Planned Capacity	279	90	-67.8%
Net Firm Capacity Transfers	-566	-622	9.9%
Anticipated Resources	5,418	5,332	-1.6%
Existing-Other Capacity	33	36	9.5%
Prospective Resources	5,451	5,368	-1.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.1%	15.3%	-2.8
Prospective Reserve Margin	18.8%	16.1%	-2.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,781	3,839	1.5%
Demand Response: Available	67	50	-25.4%
Net Internal Demand	3,714	3,789	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,488	4,320	-3.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	250	-13.8%
Anticipated Resources	4,778	4,570	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,778	4,570	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.7%	20.6%	-8.1
Prospective Reserve Margin	28.7%	20.6%	-8.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,784	5,863	1.4%
Demand Response: Available	282	264	-6.4
Net Internal Demand	5,502	5,599	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,461	6,622	2.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	4	81	1925.0%
Anticipated Resources	6,465	6,703	3.7%
Existing-Other Capacity	0	0	-
Prospective Resources	6,465	6,703	3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.5%	19.7%	2.2
Prospective Reserve Margin	17.5%	19.7%	2.2
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,009	20,269	1.3%
Demand Response: Available	610	570	-6.6%
Net Internal Demand	19,399	19,699	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,129	31,795	-1.0%
Tier 1 Planned Capacity	162	187	15.2%
Net Firm Capacity Transfers	1,070	958	-10.5%
Anticipated Resources	33,361	32,940	-1.3%
Existing-Other Capacity	142	201	42.1%
Prospective Resources	33,769	33,641	-0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	72.0%	67.2%	-4.8
Prospective Reserve Margin	74.1%	70.8%	-3.3
Reference Margin Level	14.3%	12.3%	-2.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,255	21,402	0.7%
Demand Response: Available	614	853	39.0%
Net Internal Demand	20,641	20,549	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,051	26,301	1.0%
Tier 1 Planned Capacity	112	24	-78.6%
Net Firm Capacity Transfers	-500	17	-103.4%
Anticipated Resources	25,662	26,342	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	25,662	26,342	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	28.2%	3.9
Prospective Reserve Margin	24.3%	28.2%	3.9
Reference Margin Level	11.8%	12.0%	0.2

NPCC-New York			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,893	24,220	1.4%
Demand Response: Available	695	803	15.5%
Net Internal Demand	23,198	23,417	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,393	39,697	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,097	1,589	-24.2%
Anticipated Resources	42,490	41,285	-2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,490	41,285	--2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	83.2%	76.3%	-6.9
Prospective Reserve Margin	83.2%	76.3%	-6.9
Reference Margin Level	15.0%	15.0%	-4.6

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,699	40,642	2.4%
Demand Response: Available	2,759	2,914	5.6%
Net Internal Demand	37,217	37,728	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	42,113	42,423	0.7%
Tier 1 Planned Capacity	255	0	-100.0%
Net Firm Capacity Transfers	-417	-726	74.1%
Anticipated Resources	41,951	41,697	-0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	43,051	42,797	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.7%	10.5%	-2.2
Prospective Reserve Margin	15.7%	13.4%	-2.3
Reference Margin Level	11.3%	10.5%	-0.8

PJM			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,980	132,667	-0.2%
Demand Response: Available	6,583	5,189	-21.2%
Net Internal Demand	126,397	127,478	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	185,102	179,060	-3.3%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	-726	-872	20.1%
Anticipated Resources	184,376	178,188	-3.4%
Existing-Other Capacity	0	0	-
Prospective Resources	184,376	178,188	-3.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.9%	39.8%	-6.1
Prospective Reserve Margin	45.9%	39.8%	-6.1
Reference Margin Level	14.9%	27.0%	12.1

SERC-East			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,648	45,044	0.9%
Demand Response: Available	1,180	912	-22.7%
Net Internal Demand	43,468	44,132	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	53,287	54,226	1.8%
Tier 1 Planned Capacity	75	55	-26.6%
Net Firm Capacity Transfers	513	624	21.6%
Anticipated Resources	53,875	54,905	1.9%
Existing-Other Capacity	3	3	0.0%
Prospective Resources	53,877	54,907	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.9%	24.4%	0.5
Prospective Reserve Margin	23.9%	24.4%	0.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,745	42,282	1.3%
Demand Response: Available	1,671	1,753	4.9%
Net Internal Demand	40,074	40,529	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,008	50,196	-1.6%
Tier 1 Planned Capacity	0	1,386	-
Net Firm Capacity Transfers	-868	1,145	-231.9%
Anticipated Resources	50,140	52,727	5.2%
Existing-Other Capacity	3,601	1,255	-65.1%
Prospective Resources	53,741	54,002	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	30.1%	5.0
Prospective Reserve Margin	34.1%	33.2%	-0.9
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,582	48,470	-0.2%
Demand Response: Available	2,870	2,753	-4.1%
Net Internal Demand	45,712	45,717	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,987	62,472	0.8%
Tier 1 Planned Capacity	237	1475	522.2%
Net Firm Capacity Transfers	250	509	103.6%
Anticipated Resources	62,474	64,455	3.2%
Existing-Other Capacity	3,618	1,562	-56.8%
Prospective Resources	66,092	66,017	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.7%	41.0%	4.3
Prospective Reserve Margin	44.6%	44.4%	-0.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,513	45,101	-3.0%
Demand Response: Available	1,954	2,018	3.3%
Net Internal Demand	44,559	43,083	-3.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,097	59,638	-0.8%
Tier 1 Planned Capacity	1,102	2,265	105.6%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,674	60,990	3.9%
Existing-Other Capacity	2,895	3,090	6.8%
Prospective Resources	61,569	64,081	4.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.7%	41.6%	9.9
Prospective Reserve Margin	38.2%	48.7%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,650	43,996	5.6%
Demand Response: Available	13	278	2006.1%
Net Internal Demand	41,637	43,718	5.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,131	61,173	-9.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-359	-498	-3.3%
Anticipated Resources	70,772	60,676	-9.1%
Existing-Other Capacity	0	0	-
Prospective Resources	70,496	60,630	-8.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	70.0%	38.8%	-31.2
Prospective Reserve Margin	69.3%	38.7%	-30.6
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	66,436	70,451	6.0%
Demand Response: Available	3,302	4,868	47.4%
Net Internal Demand	63,134	65,583	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	85,478	92,387	8.1%
Tier 1 Planned Capacity	644	228	-64.6%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	86,142	92,635	7.5%
Existing-Other Capacity	0	0	-
Prospective Resources	86,710	93,203	7.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.4%	41.2%	4.8
Prospective Reserve Margin	37.3%	42.1%	4.8
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,901	11,961	0.5%
Demand Response: Available	0	0	-
Net Internal Demand	11,901	11,961	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,144	13,694	4.2%
Tier 1 Planned Capacity	1,234	1511	22.5%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,378	15,205	5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	14,378	15,205	5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.8%	27.1%	6.3
Prospective Reserve Margin	20.8%	27.1%	6.3
Reference Margin Level	11.1%	13.7%	2.6

WECC-BC			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,395	11,651	2.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,395	11,651	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,223	13,166	-0.4%
Tier 1 Planned Capacity	20	134	574.4%
Net Firm Capacity Transfers	0	110	-
Anticipated Resources	13,243	13,410	1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	13,243	13,410	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.2%	15.1%	-1.1
Prospective Reserve Margin	16.2%	15.1%	-1.1
Reference Margin Level	11.1%	13.7%	2.6

WECC-CA/MX			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	38,978	38,328	-1.7%
Demand Response: Available	749	755	0.9%
Net Internal Demand	38,230	37,573	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,287	56,405	2.0%
Tier 1 Planned Capacity	1,943	5400	177.9%
Net Firm Capacity Transfers	0	315	-
Anticipated Resources	57,231	62,120	8.5%
Existing-Other Capacity	0	0	-
Prospective Resources	57,326	62,136	8.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.7%	65.3%	15.6
Prospective Reserve Margin	50.0%	65.4%	15.4
Reference Margin Level	8.4%	11.0%	2.6

WECC-NW			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	58,605	57,408	-2.0%
Demand Response: Available	707	578	-18.3%
Net Internal Demand	57,898	56,829	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,477	77,389	1.2%
Tier 1 Planned Capacity	988	2188	121.4%
Net Firm Capacity Transfers	0	1,964	-
Anticipated Resources	77,465	81,541	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	77,730	81,558	4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.8%	43.5%	9.7
Prospective Reserve Margin	34.3%	43.5%	9.2
Reference Margin Level	13.1%	17.4%	4.3

WECC-SW			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	16,004	15,743	-1.6%
Demand Response: Available	318	285	-10.6%
Net Internal Demand	15,686	15,458	-1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,799	28,306	-5.0%
Tier 1 Planned Capacity	553	1129	104.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	30,352	29,435	-3.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,352	29,587	-2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	93.5%	90.4%	-3.1
Prospective Reserve Margin	93.5%	91.4%	-2.1
Reference Margin Level	12.2%	16.4%	4.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. In many areas, winter demand peaks in the early morning hours or other times of darkness, resulting in little or no electrical resource output from solar PV resources. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	26,082	9,683	37%	2,559	130	5%	4,884	4,688	96%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	6,220	5,548	89%
MRO-SaskPower	615	124	20%	0	0	0%	851	797	94%
NPCC-Maritimes	1,207	261	22%	42	0	0%	1,312	1,180	90%
NPCC-New England	1,463	397	27%	107	1	1%	3,565	2,472	69%
NPCC-New York	2,720	870	32%	154	13	9%	6,731	5,067	75%
NPCC-Ontario	4,943	1,433	29%	0	0	0%	8,985	5,185	58%
NPCC-Québec	3,820	1,375	36%	-	10	-	40,307	32,974	82%
PJM	11,992	3,695	31%	0	0	0%	3,027	3,027	100%
SERC-Central	28	8	28%	774	230	30%	4,967	3,315	67%
SERC-East	0	0	0%	6,245	1,483	24%	3,064	3,013	98%
SERC-Florida Peninsula	0	0	0%	3,499	1,264	36%	-	-	0%
SERC-Southeast	0	0	0%	5,234	1,889	36%	3,288	3,288	100%
SPP	33,120	6,856	21%	351	118	34%	5,465	4,996	91%
Texas RE-ERCOT	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC-AB	4,931	2,221	45%	0	0	0%	894	416	47%
WECC-BC	747	111	15%	0	0	0%	16,519	10,124	61%
WECC-CA/MX	9,443	848	9%	0	0	0%	13,957	4,606	33%
WECC-SW	3,121	994	32%	2,494	103	4%	1,202	844	70%
WECC-NW	20,697	6,319	31%	0	0	0%	41,860	22,752	54%
EASTERN INTERCONNECTION	120,404	35,318	29%	26,673	7,676	29%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,820	1,375	36%	-	10	-	40,307	32,974	82%
TEXAS INTERCONNECTION	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC INTERCONNECTION	38,940	10,494	27%	2,494	103	4%	74,432	38,742	52%
INTERCONNECTION TOTAL:	201,137	59,098	29%	45,579	10,337	23%	167,618	114,771	68%

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in the table below. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The annual probabilistic statistics for model year 2024 for the 2022 Probabilistic Assessment (ProbA) show: • Base Case: 29 MWh per year of EUE • Risk Scenario (10th percentile water flow conditions): 477 MWh per year of EUE An expected unserved energy in the 29 to 477 MWh range is a reasonable estimate for the winter 2023–2024 based on the 2022 NERC ProbA Base Case for the year 2024 given comparable loads and resources, and that water flow conditions are, as of late summer 2023, below average but still above the 10^{th} percentile.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023–2024 winter season is 0.31 hours. The estimated probability of having generation forced outages of 350 MW or greater in the winter season is 11.2%. A Risk of supply shortfall exists when generation forced outages at this level coincide with periods of high demand.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring. Preliminary results are included in this table. NPCC will publish final probabilistic assessment results in December. [11]	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this winter and a low risk of disconnecting load. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below. The assessment evaluates the probabilistic indices of LOLE, LOLH and EUE.
NPCC-Maritimes		NPCC's assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (10.6 MWh) over the November–March winter period. The Maritimes area low likelihood resource case assumed that wind capacity would be de-rated by half (1,200 to 600 MW) for every hour in December through February to simulate icing conditions and a 50% natural gas capacity curtailment (610 to 305 MW) to simulate a reduction in gas supply for December through February (dual fuel units assumed reverting to oil) and reduced transfer capabilities.

[11] Based on October 2023 revised results. The final NPCC 2023–2024 Winter Reliability Assessment be available in December 2023.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New England		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period, for all the scenarios modeled. The New England Area low likelihood resource case assumed 500 MW of additional maintenance outages, ~4,817 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties (i.e., 1,850 MW total). The NPCC Probabilistic Assessment did not evaluate a prolonged, extreme cold weather event that threatens to exhaust stored liquid fuels.
NPCC-New York		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Ontario		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Québec		NPCC's assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (92.7 MWh) over the November–March winter period. The Québec Area low likelihood resource case assumed: 1,000 MW of generation reductions.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 40% installed reserve margin, well above the target of 27%. The RRS analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages and ambient derations. The RRS report was also influenced by the extreme weather experienced in December of 2022. NERC assesses an elevated risk of energy shortfall for the upcoming winter due to the potential for a weather event on the scale of Winter Storm Elliott to cause similar generation outages from fuel and winterization issues.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Regional Entity. The base case did not include high-outage conditions similar to those experienced during Winter Storm Elliott.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	There is a 11.6% probability that ERCOT will declare an EEA1 during the highest-risk hour ending at 8:00 am. The Probabilistic Reserve Risk Model, which performs Monte Carlo simulations, determines the probability that capacity available for operating reserves for a seasonal peak load day is at or below the various EEA risk thresholds.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When wind output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When hydroelectric generation output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-CA/MX		WECC-CA/MX is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.
WECC-NW		WECC-NW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. In a scenario involving high thermal generation outages, low wind output, and low hydroelectric generation output, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-SW		WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.

August 8, 2023

President Joseph R. Biden, Jr.
The White House
1600 Pennsylvania Ave, NW
Washington, DC 20500

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20460

Dear President Biden and Administrator Regan:

Thank you for proposing standards to cut carbon pollution from existing coal and new and existing gas plants. Fossil fuel-fired power plants are responsible for almost a quarter of the climate pollution generated by the U.S. For too long, they have been allowed to dump carbon pollution into our air without limit. In recognition of the urgent threat of climate change, we encourage the U.S. Environmental Protection Agency (EPA) to finalize a stronger standard than the current proposal to achieve greater emissions reductions from more sources on the fastest possible timelines. The administration must also take action for community protections and input, including rigorous monitoring and verification of carbon emissions and co-pollutants, enforcement against violations, and meaningful engagement with communities, on the state planning process and on individual projects.

Extreme weather disasters are costing us on average more than $5,000 a second. As severe heat waves, drought, wildfires, sea level rise, severe storms, and coastal and inland flooding become more frequent, communities across the country are feeling the effects of climate change firsthand. Climate change also affects our health, causing increased incidences and/or severity of respiratory illnesses, heat-related illnesses, cardiovascular illnesses, infectious diseases, adverse birth outcomes, mental health impacts, and even injury and premature death. These health impacts and climate burdens can be even more severe in communities of color and low-income communities.

Finalizing strong carbon pollution standards for power plants is one of the best tools this administration has to get us on track to meet President Biden's goal of cutting climate pollution in half by 2030. EPA has this authority under Section 111 of the Clean Air Act and Congress recently reaffirmed this authority in the Inflation Reduction Act (IRA).

We have a moral responsibility to act now to protect the well-being of our children and future generations. Strong EPA standards for fossil fuel power plants will be an important step to cut the climate pollution causing dangerous and costly climate change. We urge you to move quickly to finalize these important standards by April 2024. Our climate can't wait.

Sincerely,

Accelerate Neighborhood Climate Action (ANCA)
Action for the Climate Emergency (ACE)
Alaska Environment
Alliance of Nurses for Healthy Environments
American Sustainable Business Network (ASBN)
Arizona Climate Action Coalition
Arizona Interfaith Power & Light
Arizona Wildlife Federation
Arizonans for Community Choice
Asthma & Allergy Foundation of America - Michigan Chapter
Asthma and Allergy Foundation of America
Battle Born Progress
Black Millennials 4 Flint
Blue Future
C40 Cities
California PIRG (Public Interest Research Group)
California PIRG Students
Center for American Progress
Change the Chamber*Lobby for Climate
Chesapeake Climate Action Network Action Fund
City of Laconia NH
Clean Energy for America
Clean Water Action
CLEO Institute
Climate Action Campaign
Climate Action PA
Colorado PIRG
Connecticut PIRG
Conservation Voters of PA
Dayenu: A Jewish Call to Climate Action
Defend Our Future
Dream.org
EARTHDAY.ORG
Earthjustice
Elders Climate Action
Elders Climate Action - AZ

Elected Officials to Protect America
Endangered Species Coalition
Environment America
Environment Arizona
Environment California
Environment Colorado
Environment Connecticut
Environment Florida
Environment Georgia
Environment Illinois
Environment Iowa
Environment Maine
Environment Maryland
Environment Massachusetts
Environment Michigan
Environment Minnesota
Environment Missouri
Environment Montana
Environment Nevada
Environment New Hampshire
Environment New Jersey
Environment New Mexico
Environment New York
Environment North Carolina
Environment Ohio
Environment Oregon
Environment Rhode Island
Environment Texas
Environment Virginia
Environment Washington
Environmental Defense Fund
Environmental Law & Policy Center
Environmental Protection Network
Evangelical Environmental Network
Evergreen Action
Faith in Action Nevada
Faith in Place
First Focus on Children
Florida PIRG
Georgia Interfaith Power and Light
Georgia PIRG
Grand Rapids Climate Coalition
Green the Church Louisiana
GreenLatinos

Group Against Smog & Pollution
Health Care Without Harm
Healthy Climate Wisconsin
Healthy Environment Alliance of Utah (HEAL Utah)
Illinois Association of School Nurses
Illinois PIRG
Information Network for Responsible Mining
Institute for a Progressive Nevada
Iowa PIRG
League of Conservation Voters
Maryland PIRG
Massachusetts PIRG
Medical Society Consortium on Climate and Health
Michigan Clinicians for Climate Action (MiCCA)
Michigan League of Conservation Voters
Michigan Sustainable Business Forum
Missouri PIRG
Moms Clean Air Force
Moms Clean Air Force Arizona
Moms Clean Air Force Colorado
Moms Clean Air Force Iowa
Moms Clean Air Force Michigan
Moms Clean Air Force Montana
Moms Clean Air Force Nevada
Moms Clean Air Force New Mexico
Moms Clean Air Force Ohio
Moms Clean Air Force Pennsylvania
Moms Clean Air Force Texas
Montana PIRG
Mormon Environmental Stewardship Alliance
National Medical Association
National Parks Conservation Association
National Wildlife Federation
Nevada Conservation League
Nevada Wildlife Federation
New Hampshire PIRG
New Jersey PIRG
New Mexico Environmental Law Center
New Mexico PIRG
NH Healthcare Workers for Climate Action
North Carolina PIRG
Northern Arizona University
Ohio PIRG
Oregon Student PIRG

PennEnvironment
PennEnvironment
PennFuture
Pennsylvania PIRG
People First Economy
Physicians for Social Responsibility
Physicians for Social Responsibility Pennsylvania (PSR PA)
Poder Latinx
Public Interest Research Group in Michigan (PIRGIM)
Rail Pollution Protection Pittsburgh (RP3)
Rep GA Institute Inc
Respiratory Health Association
Rhode Island PIRG
Sierra Club
Society of Latinx Nurses
Southern Alliance for Clean Energy
SOWEGA Rising
Texas PIRG
The Climate Reality Project
The United Methodist Church - General Board of Church and Society
Three Rivers Waterkeeper
U.S. PIRG
UnidosUS
Union for Reform Judaism
Union of Concerned Scientists
US Partnership for Education for Sustainable Development
Voices for Progress
Voters of Tomorrow
Washington PIRG
West Michigan Environmental Action Council
Wisconsin Environment
Wisconsin PIRG
Young Evangelicals for Climate Action
ZERO TO THREE

Congress of the United States
Washington, DC 20515

July 31, 2023

The Honorable Michael S. Regan Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue N.W.
Washington, DC 20460

Dear Administrator Regan:

We write to commend the Environmental Protection Agency (EPA) for proposing standards to cut carbon pollution from fossil fuel-fired power plants and to thank you for your leadership on efforts to cut climate pollution and protect public health. We believe EPA's proposal is a critically important step forward, and we encourage the agency to achieve greater emissions reductions from more sources on the fastest possible timelines in recognition of the threat and growing costs of climate change. We urge you to move swiftly to finalize the strongest possible carbon pollution standards for power plants by early 2024.

EPA's recent proposals address carbon pollution from existing coal plants and existing and new natural gas-fueled power plants to tackle the stark threat that climate pollution poses to Americans' health and welfare.[1] EPA has the authority and the obligation under Section 111 of the Clean Air Act (CAA) to protect Americans from pollution sources that cause, or significantly contribute to, air pollution that endangers public health or welfare—such as carbon pollution from power plants. Congress reaffirmed this authority in the Inflation Reduction Act (IRA) by explicitly providing funding and direction for EPA to regulate power plants' carbon pollution using existing authorities, which include those in Section 111. Congress was clear: EPA can and must use its CAA authority to establish carbon pollution standards for power plants.[2]

To cut pollution as sharply as is necessary to avoid the worst impacts of climate change, we must reduce the climate pollution that comes from burning fossil fuels. The power sector is responsible for more than one quarter of U.S. greenhouse gas emissions.[3] Achieving reductions in this sector is a necessity if we are to cut climate pollution in half by 2030, as President Biden has committed to doing. Furthermore, it is key to decarbonizing other high-polluting sectors of our economy that are increasingly electrifying—including transportation and construction.[4]

As your agency works to finalize these rules, we encourage robust engagement with impacted workers and unions, as well as the communities that have experienced the most harm from our fossil fuel economy and are on the frontlines of the climate crisis. These standards must include a strong commitment to advancing environmental justice and monitoring and verifying facility compliance. In addition, EPA should move swiftly to update requirements outside of clean air authorities to ensure such facilities are held to the highest health and safety standards in order to protect frontline communities. Beyond the EPA, departments and agencies with jurisdiction over other aspects of these facilities and any control technologies employed should also improve safeguards to protect frontline communities. We are also looking for the administration to recommit to its new investment programs in good, union, clean energy jobs, including and especially through the Interagency

1 https://www.catf.us/work/power-plants/coal-pollution/

2 https://earthjustice.org/article/what-does-west-virginia-v-epa-mean-for-climate-action

3 https://www.c2es.org/content/regulating-power-sector-carbon-emissions/

4 https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

Working Group on Coal and Power Plant Communities and Revitalization to help communities navigate the energy transition that is already well underway.

Promulgating strong carbon pollution standards for power plants is one of the most effective tools President Biden's administration has to tackle climate change. It is critical that these proposed rules be strengthened and finalized by no later than March 2024. We look forward to supporting the EPA in its crucial work to address climate pollution and ensure healthier air, with these standards and beyond.

Sincerely,

Kathy Castor
Member of Congress

Mike Levin
Member of Congress

Mike Quigley
Member of Congress

Doris Matsui
Member of Congress

Paul D. Tonko
Member of Congress

Jerrold Nadler
Member of Congress

Maxine Waters
Member of Congress

Deborah K. Ross
Member of Congress

Adriano Espaillat
Member of Congress

Nanette Diaz Barragán
Member of Congress

Ted W. Lieu
Member of Congress

Yvette D. Clarke
Member of Congress

Mark DeSaulnier
Member of Congress

Eleanor Holmes Norton
Member of Congress

Emanuel Cleaver, II
Member of Congress
Ranking Member, Subcommittee on Housing, Community Development, and Insurance

Katie Porter
Member of Congress

Kevin Mullin
Member of Congress

Earl Blumenauer
Member of Congress

Jennifer L. McClellan
Member of Congress

Henry C. "Hank" Johnson, Jr.
Member of Congress

Jan Schakowsky
Member of Congress

Chellie Pingree
Member of Congress

Donald M. Payne, Jr.
Member of Congress

Julia Brownley
Member of Congress

Gerald E. Connolly
Member of Congress

Betty McCollum
Member of Congress

Barbara Lee
Member of Congress

Seth Magaziner
Member of Congress

Bennie G. Thompson
Member of Congress

Veronica Escobar
Member of Congress

Raúl M. Grijalva
Member of Congress

Dwight Evans
Member of Congress

Greg Casar
Member of Congress

Bonnie Watson Coleman
Member of Congress

Mark Pocan
Member of Congress

André Carson
Member of Congress

Summer Lee
Member of Congress

John P. Sarbanes
Member of Congress

Jill Tokuda
Member of Congress

Debbie Dingell
Member of Congress

Zoe Lofgren
Member of Congress

Teresa Leger Fernández
Member of Congress

Mark Takano
Member of Congress

Ritchie Torres
Member of Congress

Jamie Raskin
Member of Congress

Melanie Stansbury
Member of Congress

Suzanne Bonamici
Member of Congress

Glenn Ivey
Member of Congress

Donald S. Beyer Jr.
Member of Congress

James P. McGovern
Member of Congress

Alexandria Ocasio-Cortez
Member of Congress

Tony Cárdenas
Member of Congress

David J. Trone
Member of Congress

Steve Cohen
Member of Congress

Dina Titus
Member of Congress

Ann McLane Kuster
Member of Congress

C. A. Dutch Ruppersberger
Member of Congress

Juan Vargas
Member of Congress

Nydia M. Velázquez
Member of Congress

Jared Huffman
Member of Congress

Cori Bush
Member of Congress

Adam B. Schiff
Member of Congress

Dan Goldman
Member of Congress

Sydney Kamlager-Dove
Member of Congress

Frederica S. Wilson
Member of Congress

Jesús G. "Chuy" García
Member of Congress

Jimmy Gomez
Member of Congress

Matt Cartwright
Member of Congress

Mary Gay Scanlon
Member of Congress

Joe Neguse
Member of Congress

Salud Carbajal
Member of Congress

Andy Kim
Member of Congress

Darren Soto
Member of Congress

Al Green
Member of Congress

Valerie P. Foushee
Member of Congress

Diana DeGette
Member of Congress

Mike Thompson
Member of Congress

Shri Thanedar
Member of Congress

Robert Garcia
Member of Congress

Sara Jacobs
Member of Congress

Pramila Jayapal
Member of Congress

Terri A. Sewell
Member of Congress

Bradley Scott Schneider
Member of Congress

Maxwell Alejandro Frost
Member of Congress

Josh Gottheimer
Member of Congress

Danny K. Davis
Member of Congress

Lori Trahan
Member of Congress

Robert C. "Bobby" Scott
Member of Congress

Gabe Vasquez
Member of Congress

Adam Smith
Member of Congress

Brendan F. Boyle
Member of Congress

Lois Frankel
Member of Congress

Grace Meng
Member of Congress

Andrea Salinas
Member of Congress

Nikema Williams
Member of Congress

John Garamendi
Member of Congress

Ruben Gallego
Member of Congress

Rashida Tlaib
Member of Congress

Jamaal Bowman, Ed.D.
Member of Congress

Raja Krishnamoorthi
Member of Congress

Comments of the Attorneys General of New York, Arizona, California, Connecticut, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Mexico, North Carolina, Oregon, Pennsylvania, Rhode Island, Vermont, Washington, Wisconsin, and the District of Columbia, and the Chief Legal Officers of the City and County of Denver, and the Cities of Boulder (CO), Chicago, Los Angeles, New York, and Philadelphia

on

the U.S. Environmental Protection Agency's Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Generating Units; and
Repeal of the Affordable Clean Energy Rule,
88 Fed. Reg. 33,240 (May 23, 2023)
EPA-HQ-OAR-2023-0072

August 8, 2023

Table of Contents

EXECUTIVE SUMMARY

The undersigned Attorneys General of New York, Arizona, California, Connecticut, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Mexico, North Carolina, Oregon, Pennsylvania, Rhode Island, Vermont, Washington, Wisconsin, and the District of Columbia, and the chief legal officers of the City and County of Denver, the Cities of Boulder (CO), Chicago, Los Angeles, New York, and Philadelphia (together, "Attorneys General") submit these comments on the Environmental Protection Agency's proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (May 23, 2023) (Proposed Rule).

The Proposed Rule comes at a critical time. The United States, like much of the world, is experiencing climate change impacts on a daily basis: from sweltering temperatures in our cities, to severe droughts, damaging wildfires, poor air quality, and lethal flash floods. The elements of our infrastructure—roads, bridges, sewer and stormwater systems, and, of particular relevance to this rulemaking, electrical grids—are under near constant stress from extreme weather, driven in part by the emission of carbon dioxide (CO_2) and other greenhouse gas pollutants. And although many of our states have made significant strides in reducing CO_2 emissions from power plants, nationwide carbon pollution limits on the power sector are necessary as part of a worldwide commitment to address climate change if we are to avoid ever-worsening climate change impacts.

Fortunately—and unlike in 2015, the last time that EPA made a serious attempt to limit power plant CO_2 pollution—Congress has enacted legislation to put the U.S. on a path to substantially reduce carbon emissions from the power sector. That legislation, the Inflation Reduction Act, is a game-changer for EPA's rulemaking here, in two fundamental ways: First, by enacting generous tax credits for technologies such as carbon capture and sequestration (CCS) that power plants can use to significantly reduce CO_2, Congress dramatically reduced the costs of compliance with emission reduction requirements based on such technologies, one of the factors EPA must consider in establishing emission limits under section 111 of the Clean Air Act. Second, by expressly directing EPA to use its existing authority under section 111 to ensure that power plants cut their carbon pollution, Congress made clear that it expects EPA to use that authority to promulgate meaningful CO_2 emission reductions necessary to help us confront the climate crisis.

The Proposed Rule is firmly grounded in these two aspects of the Inflation Reduction Act. EPA's proposed emission limits for coal-fired and gas-fired power plants reflect the changed economics for pollution control technologies brought about by the legislation. In addition, EPA has used its existing authority to propose meaningful limits on these two large sources of carbon pollution. The agency further based these emission limits on the type of source-specific approaches that fit comfortably within the four corners of the Supreme Court's decision last year in *West Virginia v. EPA*. Indeed, the Proposed Rule's emission limits are based on the use of pollution control systems, such as CCS and co-firing with hydrogen, that many of the states that were petitioners in *West Virginia* have embraced. Relatedly, we fully support EPA's proposed repeal of the Trump Administration's Affordable Clean Energy (ACE) rule, which had multiple legal defects and did nothing to require power plants to reduce their greenhouse gas emissions.

Although we are largely supportive of the Proposed Rule, there are areas in which EPA should modify and strengthen it:

- ***Pollution limits on new gas-fired combustion turbines***. EPA should select one best system of emission reduction for new, modified, and reconstructed base load natural gas electric generating units. We further urge EPA to identify a single standard of performance for these units—with phased stringency as necessary—based on EPA's determination of the single best system of emission reduction. EPA should also consider finalizing more stringent emission limits for new peaking units.

- ***Pollution limits on existing gas-fired combustion turbines***. As suggested above regarding new base load combustion turbines, EPA should similarly select one best system and set one presumptive emission limit for existing gas-fired units subject to the final rule. Next, EPA should expand coverage of the Proposed Rule's emission limits by lowering the capacity factor and size requirements. Increasing the scope of the rule's emission reduction requirements is both economically justified and necessary in order to protect against climate change harms. We further urge EPA to promptly undertake a supplemental rulemaking to establish emission limits for low-load "peaking" units. These inefficient units, which could see increased use while they are exempt from section 111 requirements, are often located in communities that have experienced a disproportionate share of pollution relative to other areas. As a result, promptly addressing their emissions should be an environmental justice priority.

- ***Pollution limits on existing coal-fired electric generating units.*** EPA should move up by two years (to January 1, 2038) the date on which coal-fired generating units are categorized as long-term units, and thereby required to achieve an emission limit of 90 percent CO_2 capture. The agency should also consider more closely approaches that imminent-term and near-term generating units can take to further limit their CO_2 emissions, especially for those units located in communities that have already experienced a disproportionate share of power plant pollution.

Next, EPA should improve its analysis of the potential environmental justice impacts of the rule. The statute's "nonair quality health and environmental impact" language authorizes EPA to evaluate cumulative impacts, including in frontline and downwind communities, in determining the best system of emission reduction that has been adequately demonstrated. EPA therefore should expand the scope of its Environmental Justice Impacts analysis included with the Proposed Rule to fully assess cumulative health and environmental impacts of the Proposed Rule on underserved communities.[1]

Finally, we generally support the Proposed Rule's provisions regarding state plan requirements for regulating existing coal-fired and natural gas-fired electric generating units. EPA appropriately proposes to allow state plans to include emissions trading and averaging, provided that such approaches will achieve at least equivalent emission reduction as applying EPA's best system of emission reduction. EPA should make clear that states may use an existing or future trading program developed independently of the rule in such state plans, so long as the trading program provides at least the aggregate level of emission control as EPA's emissions guidelines for affected sources, taking into account any standards

[1] "Underserved communities" refers to populations sharing a particular characteristic, as well as geographic communities, that have been systematically denied a full opportunity to participate in aspects of economic, social, and civic life, such as Black, Latino, and Indigenous and Native American persons, Asian Americans and Pacific Islanders and other persons of color; members of religious minorities; lesbian, gay, bisexual, transgender, and queer (LGBTQ+) persons; persons with disabilities; persons who live in rural areas; and persons otherwise adversely affected by persistent poverty or inequality. *See* Executive Order 13,985, Advancing Racial Equity and Support for Underserved Communities Through the Federal Government, 86 Fed. Reg. 7009 (Jan. 25, 2021).

imposed through application of remaining useful life and other factors. Recognizing that addressing existing source pollution can sometimes result in disproportionate pollution and related impacts, we support requiring that state plans include provisions for robust and meaningful engagement with any communities affected by these power plants. We also support EPA's approach to state plans applying "remaining useful life and other factors" under section 111(d): namely that in situations in which the agency's presumptive standard of performance is not reasonably achievable for a particular source, the state plan should still impose the most stringent standard of performance feasible under the circumstances. Relatedly, states contemplating a less stringent standard of performance for an electric generating unit based on remaining useful life should have to consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the source.

The body of our comments is organized as follows: Section I is an introduction that contains a discussion of (A) recent scientific reports on climate change harms, (B) a summary of threats that our states and cities are facing from climate change, (C) a description of efforts our states and cities have undertaken to reduce carbon dioxide emissions from the electricity generating sector, (D) background on environmental justice, (E) key statutory concepts, (F) relevant litigation background, and (G) a discussion of the clean electricity program in the Inflation Reduction Act. In Section II, we discuss EPA's proposed repeal of the ACE rule. In Section III, we address EPA's proposed performance standards for new natural gas combustion turbines under section 111(b) of the Clean Air Act and the proposed emission limitations for existing natural gas combustion turbines under section 111(d) of the Act. Section IV sets forth our comments on EPA's proposed emission guidelines under section 111(d) of the Act for states to set limits on greenhouse gas emissions from existing coal-fired power plants. Section V discusses environmental justice considerations that should inform EPA's rulemaking. In Section VI, we provide our comments on the state plan section of the rulemaking. Finally, we offer some concluding thoughts.

I. INTRODUCTION

A. Recent Evidence of Climate Change

The March 2023 report by the Intergovernmental Panel on Climate Change (IPCC) states that human activities, principally through emissions of greenhouse gasses, have unequivocally caused global warming.[2] Based on the annual report from National Oceanic and Atmospheric Administration's (NOAA's) Global Monitoring Lab, global average atmospheric carbon dioxide was 417 parts per million in 2022, a new record high.[3] The global surface temperature has increased faster since 1970 than in any other 50-year period over at least the last 2000 years.[4] For the last 8 consecutive years, annual global temperatures have reached at least 1°C above pre-industrial levels, with the temperature reaching 1.15 °C above the pre-industrial levels in 2022.[5] So far, 2023 is even warmer. A new report shows that the week of July 3, 2023 was the hottest ever recorded globally.[6] Temperatures are also getting higher earlier in the year; according to NOAA, April 2023 ranked as the world's fourth-warmest April on record.[7]

Droughts and Fires

A warming climate can contribute to the intensity of heat waves by increasing the chances of very hot days and nights. A recent study found that droughts that stretched across three continents in summer 2022—drying out large parts of Europe, the United States and China—were made 20 times more likely by

---

[2] Intergovernmental Panel on Climate Change (IPCC), "Climate Change 2023 Synthesis Report," (IPCC 2023 Synthesis Report) *www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_LongerReport.pdf.*

[3] Nat'l Oceanic and Atmospheric Admin., "Climate Change: Atmospheric Carbon Dioxide," https://www.climate.gov/news-features/understanding-climate/climate-change-atmospheric-carbon-dioxide#:~:text=The%20global%20average%20carbon%20dioxide,was%20before%20the%20Industrial%20Revolution.

[4] IPCC 2023 Synthesis Report at 6.

[5] World Meteorological Organization, "Past Eight Years Confirmed to Be the Eight Warmest on Record," (Jan. 11, 2023), https://public.wmo.int/en/media/press-release/past-eight-years-confirmed-be-eight-warmest-record#:~:text=The%20average%20global%20temperature%20in,all%20datasets%20compiled%20by%20WMO.

[6] The Guardian, "Monday Was Hottest Day for Global Average Temperature on Record, as Climate Crisis Bites," (July 4, 2023), https://www.theguardian.com/world/2023/jul/04/monday-was-hottest-day-for-global-average-temperature-on-record-as-climate-crisis-bites.

[7] Nat'l Oceanic and Atmospheric Admin., "Global climate summary for April 2023," https://www.climate.gov/news-features/understanding-climate/global-climate-summary-april-2023#:~:text=April%202023%20was%20the%20fourth,months%20have%20occurred%20since%202010.

climate change.[8] This analysis was done by using the warming the climate has already experienced so far, 1.2 °C. Climate change-driven droughts are now expected to happen every year throughout the Northern Hemisphere. Another study that examined 152 extreme heat events from around the globe concluded that climate change made 93 percent of the events more likely or more severe.[9] These events include Siberia's heatwave of 2020, the Pacific north-west "heat dome" event of 2021, and Europe's record-breaking summer of 2021. And 37 percent of warm-season heat-related deaths across 43 countries between 1991 and 2018 can be attributed to anthropogenic climate change, and that increased mortality is evident on every continent.[10]

Climate warming also increases evaporation on land, which can worsen drought and create more favorable conditions for wildfires and a longer wildfire seasons. Scientific evidence shows that around the world, fire regimes (the characteristic pattern of fire established over time and space) are being altered due to climate change. A recent report from the United Nations found that, although the impact of climate change on fire behavior in the future is complex, current models suggest that some areas, such as the Arctic, are very likely to experience a significant increase in burning by the end of the century. Areas of tropical forest in Indonesia and the southern Amazon are also likely to see increased burning if greenhouse gas emissions continue at their current rate. There will also be significant changes in the number of hectares of land burned in landscapes that currently experience burning.[11] Most recently, Canada's 2023 wildfire season is breaking records. With more than two months still to go in the country's fire season, the 9 million hectares already burned has outstripped the fire season of 1989, the

---

[8] PBS, "Climate Change Made Global Summer Droughts 20 Times More Likely" (Oct. 5, 2022), https://www.pbs.org/newshour/science/climate-change-made-global-summer-droughts-20-times-more-likely.

[9] Carbon Brief, "Mapped: How Climate Change Affects Extreme Weather around the World" (Aug. 4, 2022), https://www.carbonbrief.org/mapped-how-climate-change-affects-extreme-weather-around-the-world/.

[10] *Id.*

[11] UNEP - UN Environment Programme, "Spreading like Wildfire: The Rising Threat of Extraordinary Landscape Fires" (Feb. 22, 2022), https://www.unep.org/resources/report/spreading-wildfire-rising-threat-extraordinary-landscape-fires.

previous worst on record—with significant impacts on air quality throughout North America.[12]

Rainfall and Flooding

Flooding from heavy rainfall events is a dangerous phenomenon that has become increasingly probable and severe due to climate change. As air temperatures increase, more water vapor may be held in the atmosphere and discharged during rainfall events. For every one degree Celsius increase in temperature, 7 percent more water vapor is carried by the same air volume. As a result, record rainfall extremes have continued to increase worldwide and, on average, 1 in 4 record rainfalls in the last decade can be attributed to climate change.[13] A recent study concluded that from 2015–2021, the frequency of extreme wet (and dry) events was four per year, compared with three per year in the preceding 13 years.[14] A June 2023 study of rainfall in the United States found in much of the Northeast, the Ohio River Basin, Northwestern California, the Texas Gulf Coast and the Mountain West, the rainfall depths for a 1-in-100-year event could happen far more frequently, with estimates suggesting these types of heavy rain events at least every 5 to 10 years.[15]

Additionally, NOAA's 2022 global climate report highlights how extreme rainfall is a global problem. For example, in that year alone, heavy rain in northern Puerto Rico triggered dangerous floods, landslides, downed trees, and power lines. The city of San Juan, Puerto Rico's capital, had a monthly rainfall total of 301 mm (11.85 inches), which is San Juan's wettest February on record and the eighth-wettest month for any month on record. Copious rain fell across parts of Portugal and western and central Spain in mid-December, causing devastating floods that

---

[12] Natural Resources Canada, et al. "North American Seasonal Fire Assessment and Outlook," (Jul. 12, 2023), https://www.nifc.gov/nicc-files/predictive/outlooks/NA_Outlook.pdf.

[13] Robinson, et al., "Increasing Heat and Rainfall Extremes Now Far Outside the Historical Climate," *NPJ Climate and Atmospheric Science*, vol. 4, no. 1 at 1–4 (Oct. 2021), www.nature.com, https://doi.org/10.1038/s41612-021-00202-w.

[14] Nat'l Aeronautic and Space Admin., "Warming Makes Droughts, Wet Events More Frequent, Intense," (Mar. 10, 2023), https://www.nasa.gov/feature/warming-makes-droughts-extreme-wet-events-more-frequent-intense.

[15] First Street Foundation, "Highlights From the Precipitation Problem" (June 26, 2023), https://firststreet.org/research-lab/published-research/article-highlights-from-the-precipitation-problem/.

damaged or destroyed roads and homes. It was reported that rainfall totals in the affected areas in Spain were over 90 mm (3.5 inches) in just 24-hours.[16]

Hurricanes and Storms

Earth's warmer and moister atmosphere, combined with warmer oceans, make it likely that the strongest hurricanes will be more intense, produce more rainfall, affect new areas, and possibly be larger and longer-lived.[17] In 2022, when Hurricane Ian hit Florida, it was one of the United States' most powerful hurricanes on record, and it followed a two-week string of massive, devastating storms around the world. A few days earlier in the Philippines, Typhoon Noru gave new meaning to rapid intensification when it strengthened from a tropical storm with 50 mph winds to a Category 5 with 155 mph winds within 24 hours. Hurricane Fiona flooded Puerto Rico, then became Canada's most intense storm on record. Typhoon Merbok gained strength over a warm Pacific Ocean and tore up over 1,000 miles of the Alaska coast.[18] While most models show either no change or a decrease in hurricane frequency in a warmer climate, a greater proportion of the storms that form will reach very intense (Category 4 or 5) levels. In short, there may be fewer storms, but the ones that do form will have a greater chance of becoming stronger.[19]

Oceans

The oceans are absorbing more heat as greenhouse gases trap more energy from the sun, causing changes such as temperature increase, sea level rise, and acidification. Oceans absorb around 90 percent of the Earth's accumulated heat and 23 percent of the carbon dioxide emissions from human activity. Reflecting this, global ocean temperatures set a record high for April 2023 at 1.55 °F (0.86 °C) above the long-term average, marking the second-highest monthly ocean temperature for

---

[16] Nat'l Centers for Environmental Information, "2022 Global Climate Report". *National Oceanic and Atmospheric Administration*, https://www.ncei.noaa.gov/access/monitoring/monthly-report/global/202213.

[17] The Royal Society, "How does climate change affect the strength and frequency of floods, droughts, hurricanes, and tornadoes?" (Mar. 2020), https://royalsociety.org/topics-policy/projects/climate-change-evidence-causes/question-13/.

[18] Camargo, S. and Barlow, M., "Here's What We Know About How Climate Change Fuels Hurricanes," Columbia Climate School, *State of the Planet* (Oct. 3, 2022), https://news.climate.columbia.edu/2022/10/03/heres-what-we-know-about-how-climate-change-fuels-hurricanes/.

[19] Nat'l Aeronautic and Space Admin., "A Force of Nature: Hurricanes in a Changing Climate," (Jun. 1, 2022), https://climate.nasa.gov/news/3184/a-force-of-nature-hurricanes-in-a-changing-climate/.

any month on record.[20] Rising ocean temperatures cause the sea level to rise due to thermal expansion and melting glaciers: the average rate of sea level rise along U.S. coasts was 1.3 mm (0.05")/year between 1901 and 1971, 1.9 mm (0.075")/year between 1971 and 2006, and 3.7 mm (0.15")/year between 2006 and 2018.[21] Sea level along the U.S. coastline is projected to rise 254 mm to 305 mm (10" – 12") in the next 30 years. Similarly, global sea level is rising. The 2021 global sea level set a new record high of 97 mm (3.8 inches) above 1993 levels.[22] Additionally, the ocean is also now its most acidic in at least 26,000 years as it absorbs and reacts with more carbon dioxide in the atmosphere.[23] By the end of this century the ocean is expected to be 150 percent more acidic than it is now.[24]

Irreversible Impacts

The IPCC has found that the likelihood and impacts of abrupt and/or irreversible changes in the climate system, including changes triggered when tipping points are reached—such as the risks of species extinction—increase with further global warming.[25] A 2022 study concluded that we may have already crossed some tipping point thresholds with the 1.1 °C increase in global temperature warming that humans have caused so far. The ice shelf of the 80-mile-wide Thwaites Glacier located in West Antarctica, for example, could shatter in as little as five years, sliding into the ocean and significantly contributing to sea level rise.[26] Similarly, Greenland's ice sheet is melting; even if emissions were halted today, the melting will cause 254 mm (10") of sea level rise. Another new study suggests that

---

[20] Nat'l Oceanic and Atmospheric Admin., "April 2023 was Earth's fourth warmest on record" (May 12, 2023), https://www.noaa.gov/news/april-2023-was-earths-fourth-warmest-on-record.

[21] Nat'l Oceanic and Atmospheric Admin., "2022 Sea Level Rise Technical Report," https://oceanservice.noaa.gov/hazards/sealevelrise/sealevelrise-tech-report.html.

[22] Nat'l Oceanic and Atmospheric Admin., "Climate Change: Global Sea Level," (Apr. 19, 2022), https://www.climate.gov/news-features/understanding-climate/climate-change-global-sea-level.

[23] World Meteorological Organization, "State of the Global Climate 2021," (2022).

[24] The Economist, "The Threat of Ocean Acidification," (Feb. 2, 2023), https://www.economist.com/films/2023/02/02/the-threat-of-ocean-acidification.

[25] IPCC, Climate Change 2023 Synthesis Report: Summary for Policymakers at 18 (2023), https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_SPM.pdf.

[26] Pettit, et al., "Collapse of Thwaites Eastern Ice Shelf by intersecting fractures" (Dec. 2021), https://ui.adsabs.harvard.edu/abs/2021AGUFM.C34A..07P/abstract.

the jet stream is currently at its weakest state in more than 1,000 years.[27] Ecosystems are also being irreversibly impacted. As noted by IPCC estimates, as much as 90 percent of all warm water coral reefs will die off even if warming is kept to 1.5 °C. If the temperature creeps higher, it's likely to mark the first-ever man-made extinction of an entire ecosystem.

B. Climate Change-Related Harms Impacting States and Cities

Our states and cities are now experiencing climate change-related harms on a daily basis. Attached to these comments as ***Appendix 1*** is a detailed discussion of some of those impacts. This subsection highlights several of these recent harms:

- In Oregon, exposure to wildfire smoke during the 2020 wildfire season was associated with additional COVID-19 cases in 15 of 20 counties with high particulate matter ($PM_{2.5}$). High levels of $PM_{2.5}$ on wildfire days accounted for up to 15 percent of total COVID-19 cases.[28]

- In late June/early July 2021, the Pacific Northwest experienced a "once-in-a-millennium" heat wave that caused 100 heat-related deaths in Washington,[29] and an additional 38 deaths related to the heat wave after it had ceased.[30] Of the heat deaths in the summer of 2021, 67 percent were victims over the age of 65.[31] In addition to the human death toll, the heat was so intense that hundreds of millions of shellfish baked to death in the Puget Sound.[32]

---

[27] Courtney Lindwall, "Climate Tipping Points Are Closer Than Once Thought," (Nov. 15, 2022), https://www.nrdc.org/stories/climate-tipping-points-are-closer-once-thought.

[28] Oregon Health Authority, *Climate and Health in Oregon: 2020 Report* at 9.

[29] The Seattle Times, "Window shades, ventilation and other key lessons from the 2021 Pacific Northwest heat wave," (June 25, 2022), https://www.seattletimes.com/seattle-news/environment/window-shades-ventilation-and-other-key-lessons-from-the-2021-pacific-northwest-heat-wave/; Wash. State Dep't of Health, *Heat Wave 2021*, https://doh.wa.gov/emergencies/be-prepared-be-safe/severe-weather-and-natural-disasters/hot-weather-safety/heat-wave-2021 (last visited July 12, 2023).

[30] *Heat Wave 2021*

[31] *Id.*

[32] *See* John Ryan, "Extreme heat cooks shellfish alive on Puget Sound beaches," *KUOW Puget Sound Public Radio* (June 23, 2022), https://www.kuow.org/stories/extreme-heat-wave-cooked-many-shellfish-spared-others-study-finds.

- In September 2021, powerful remnants of Hurricane Ida caused lethal flash flooding in Connecticut, New Jersey, New York, and Pennsylvania, killing more than 40 people and leaving more than 150,000 homes without power.[33]

- In 2022, California saw over 9,900 wildfires burn about 4.3 million acres, more than twice the previous record of acres burned.[34]

- In 2022, Massachusetts experienced significant or critical drought conditions across the entire state, leading to drought-induced fires, water restrictions, and water quality and availability impacts on private wells and water-dependent habitats across the state.[35]

- On July 10–11, 2023, an intense storm dumped as much as 9 inches of rain on Vermont, at a time when rivers were high and soils saturated from prior storms.[36] The storm caused catastrophic flooding in downtown Montpelier, the state's capital, and numerous other cities and towns. By the evening of July 11, more than 175 rescue operations had been conducted to reach stranded Vermonters, many conducted by boat.

C. State and Local Efforts to Reduce Carbon Dioxide Emissions from the Electric Generating Sector

Our states and cities are acting to address the threats posed by climate change, including by reducing power plant carbon pollution. As detailed in ***Appendix 2*** to these comments, these programs, which include statewide cap-and-trade, regional cap-and-trade, and renewable portfolio standards (RPS), have resulted in substantial CO_2 emission reductions without increasing consumer

---

[33] New York Times, "Flooding from Ida Kills Dozens of People in Four States," (updated Oct. 13, 2021), https://www.nytimes.com/live/2021/09/02/nyregion/nyc-storm.

[34] Kerlin, Kat, and U.C. Davis, *California's 2020 Wildfire Season: Report Summarizes Record-Breaking Fire Year and Calls for Shift in Strategy* (May 4, 2022), https://phys.org/news/2022-05-california-wildfire-season-record-breaking-year.html

[35] Massachusetts Drought Status (Sept. 8, 2022), http://bit.ly/3hKCnwR (last visited Nov. 28, 2022); Press Release, Mass. Exec. Off. of Energy & Env't Aff., *Massachusetts Continues to Experience Drought Conditions* (July 21, 2022), http://bit.ly/3Vi0RfS.

[36] Seven Days Staff, *'Historic and Catastrophic': Unrelenting Rain Swamped Vermont's Cities, Towns and Hamlets. The Recovery is Just Beginning,* (Updated July 13, 2023), https://www.sevendaysvt.com/vermont/historic-and-catastrophic-unrelenting-rain-swamped-vermonts-cities-towns-and-hamlets-the-recovery-is-just-beginning/Content?oid=38643810 (last visited July 18, 2023).

electricity prices or undermining the reliability of the grid. This subsection highlights some of those efforts:

- At the end of 2019, New York enacted the Climate Leadership and Community Protection Act, which requires 70 percent of the state's electricity be generated by renewable sources by 2030 and 100 percent zero-emission electricity by 2040.[37]

- In 2019, the Washington legislature enacted the Clean Energy Transformation Act to effectuate the state's policy of eliminating coal-fired electricity and transitioning the energy sector to be carbon neutral.[38] The Act requires that all retail sales of electric power to Washington consumers must be greenhouse gas neutral by 2030[39] and 100 percent renewable by 2045.[40]

- Through the Clean Energy Jobs Act of 2019, Maryland's renewable portfolio standards increased the amount of renewable energy electricity suppliers must procure from renewables to at least 50 percent from Tier 1 renewable energy resources by 2030. Additionally, 14.5 percent of retail electricity sales must come from solar resources by 2030.[41]

- Oregon passed a law in 2021 that requires Oregon's investor-owned electric utilities to reduce greenhouse gas emissions to 80 percent below baseline levels by 2030 and to zero by 2040.[42]

- In 2021, North Carolina Governor Roy Cooper signed into law House Bill 951, "Energy Solutions for North Carolina," which requires the North Carolina Utilities Commission to take reasonable steps to achieve a 70 percent reduction in CO_2 emissions from investor-owned electric generating facilities by 2030 and carbon neutrality by 2050.[43] Between

---

[37] N.Y. Law 2019, ch. 106, § 2; N.Y. Pub. Serv. § 66-p.

[38] Wash. Laws of 2019, Ch. 288 (E2SSB 5116) (codified at Chapter 19.405 RCW).

[39] RCW § 19.405.040(1).

[40] RCW §§ 19.405.040(1), 19.405.050(1).

[41] Md. S.B. 516, 2019 Reg. Sess. (cross filed as H.B. 1158).

[42] OR. REV. STAT. § 469A.410(1)(a)–(c) (2021).

[43] N.C. Session Law 2021-165 (Oct. 13, 2021).

2007 and 2020, approximately $19.8 billion was invested in clean energy development in the state. This investment has continued to grow with the state investing $1.6 billion in renewable energy in 2020. Further, between 2007 and 2020, clean energy and energy efficiency project development had a $40.3 billion impact on North Carolina's economy.

D. Environmental Justice Considerations

1. Climate change impacts on communities with environmental justice concerns

Climate change continues to disproportionately harm underserved communities—including Black and Latinx communities, Native American tribal communities, low-income communities, and communities with low educational attainment—who already face disparate health and environmental hazards.[44] In the United States, these groups are at increased risk of exposure given their likelihood of living in risk-prone areas like urban heat islands, isolated rural areas, or coastal and other flood-prone areas, as well as areas with older or poorly maintained infrastructure, or areas higher levels of air pollution—effects that can lead to issues with food safety, infectious diseases, and psychological stressors.[45]

---

[44] *See* EPA, *Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts* at 6–7 (Sept. 2021), https://www.epa.gov/system/files/documents/2021-09/climate-vulnerability_september-2021_508.pdf; IPCC, Summary for Policymakers, in Climate Change 2022: Impacts, Adaptation and Vulnerability at 12 (2022), http://bit.ly/3EEzBCy.

[45] *See* U.S. Global Change Research Program (USGCRP), Janet L. Gamble et al., *Ch. 9: Populations of Concern in The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment* 247, 252 (2016), http://dx.doi.org/10.7930/J0R49NQX*; see also see also* EPA, *Climate Change and Social Vulnerability* at 6–7; EPA, *Climate Change, Health, & Environmental Justice* (May 2016), https://19january2017snapshot.epa.gov/sites/production/files/2016-10/documents/ej-health-climate-change-print-version_0.pdf; EPA, *Climate Change Indicators: Heat-Related Deaths* (Apr. 2021), https://www.epa.gov/climate-indicators/climate-change-indicators-heat-related-deaths#:~:text=Hot%20temperatures%20can%20also%20contribute,other%20forms%20of%20cardiovascular%20disease.&text=Certain%20population%20groups%20already%20face,variability%20will%20increase%20that%20risk; USGCRP, Marcus C. Sarofim et al., *Ch. 2: Temperature-Related Death and Illness in The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment* 43, 54–55 (2016), https://health2016.globalchange.gov/; Gordon Walker, *Environmental Justice: Concepts, Evidence and Politics,* (1st ed.) Routledge (Dec. 16, 2011); Jayajit Chakraborty & Marilyn C Montgomery, *Assessing the Environmental Justice Consequences of Flood Risk: A Case Study in Miami, Florida,* Environ. Res. Lett. 10 (2015), https://iopscience.iop.org/article/10.1088/1748-9326/10/9/095010/pdf.

Studies have found, for example, that underserved communities are especially vulnerable to ambient air pollution—like $PM_{2.5}$ pollution—due to socioeconomic and demographic factors.[46] The effects of ambient air pollution are particularly prevalent when filtering for race.[47] For example, Black and African American children are 41 percent more likely to currently reside in areas with the highest projected increases in asthma diagnoses due to climate-driven changes in air quality.[48] Additionally, Black or African American individuals are 41–60 percent more likely than from other racial demographics to experience premature mortality due to exposure to climate-driven increases in $PM_{2.5}$.[49]

Furthermore, underserved communities experience disproportionate damage from natural disasters exacerbated by climate change, especially flooding, as well as drought.[50] They also suffer from more severe climate-related impacts, including water contamination from flood pollution and increased concentration of contaminants during droughts.[51] Underserved communities often lack infrastructure necessary to control flooding or ensure steady water supplies.[52] For example, EPA found that Hispanic and Latinx individuals are 50 percent more likely to live in areas with significant risk of traffic delays due to coastal flooding than non-Hispanic populations.[53]

---

[46] *See* EPA, *Climate Change and Social Vulnerability* at 21.

[47] *Id.*

[48] *Id.* at 27–28.

[49] *Id.* at 24–25.

[50] Walker, *Environmental Justice: Concepts, Evidence, and Politics*.

[51] USGCRP, *Climate and Health Assessment*, at 158–74.

[52] Lily Katz, *A Racist Past, a Flooded Future: Formerly Redlined Areas Have $107 Billion Worth of Homes Facing High Flood Risk—25% More Than Non-Redlined Areas*, Redfin (2021), https://www.redfin.com/news/redlining-flood-risk/; Michelle Roos (E4 Strategic Solutions), *Climate Justice Summary Report, California's Fourth Climate Change Assessment* at 41–42 (2018), https://www.energy.ca.gov/sites/default/files/2019-11/Statewide%20Reports-%20SUM-CCCA4-2018-012%20ClimateJusticeSummary_ADA.pdf; USGCRP, *Climate and Health Assessment*, at 253–54; Ellen M. Douglas et al., *Coastal flooding, climate change and environmental justice: identifying obstacles and incentives for adaptation in two metropolitan Boston Massachusetts communities, Mitigation and Adaptation Strategies for Global Change* 17, 537–562 (2012), https://link.springer.com/article/10.1007/s11027-011-9340-8.

[53] *See* EPA, *Climate Change and Social Vulnerability* at 76.

Underserved communities also face disproportionate impacts from extreme heat conditions as greenhouse gas concentrations and global temperatures continue to rise,[54] including significant projected labor losses in Hispanic and Latinx communities.[55] Extreme heat days also have been linked to higher all-cause mortality rates in the contiguous United States and some subgroups, including older adults and Black adults, are disproportionately affected.[56] An EPA report, for example, found that individuals with lower incomes and individuals of color are respectively 11–16 percent and 8–14 percent more likely to live in areas with the highest projected increases in premature mortality from extreme heat.[57]

Indigenous populations who rely "on the environment for sustenance or who live in geographically isolated or impoverished communities, are also likely to experience greater exposure and lower resilience to climate related health effects."[58] Indigenous populations face not only climate related health risks such as food safety and security, water security, and degraded infrastructure, but also non-quantifiable impacts such as loss of cultural identity.[59] And Tribal communities with sovereign land holdings may also be more vulnerable to climate impacts because they are unable to relocate.[60]

---

[54] *See* EPA*, Climate Change Indicators: Heat-Related Death; USGCRP Climate and Health Assessment*, at 59; Diana Reckien, et al., *Equity, Environmental Justice, and Urban Climate Change, Climate Change and Cities: Second Assessment Report of the Urban Climate Change Research Network*, Cambridge University Press, 173–224 (2018), https://archium.ateneo.edu/cgi/viewcontent.cgi?article=1077&context=sa-faculty-pubs.

[55] *See* EPA, *Climate Change and Social Vulnerability* at 76 ("Hispanic and Latino individuals are 43% more likely than their reference population to currently live in areas with the highest projected labor losses from extreme temperatures").

[56] Sameed Ahmed M. Khatana, et al., *Association of Extreme Heat With All-Cause Mortality in the Contiguous US, 2008–2017*, JAMA Network Open (May 19, 2022), https://doi.org/10.1001/jamanetworkopen.2022.12957; John Muyskens et al., "More dangerous heat waves are on the way: see the impact by Zip code," *The Washington Post* (Aug. 15, 2022), https://www.washingtonpost.com/climate-environment/interactive/2022/extreme-heat-risk-map-us/ (by 2053, 80 percent of Black Americans and 60 percent of white Americans will be affected by dangerous heat).

[57] EPA, *Climate Change and Social Vulnerability* at 36.

[58] *See id.* at 253.

[59] *See id.* at 253–54.

[60] Justin Farnell, et al., Effects of land dispossession and forced migration on Indigenous peoples in North America, Science 374 (2021).

EPA recognizes that social determinants of health, including socioeconomic status, race and ethnicity, education level, and age, are all indicators of how adequately a population can prepare for and respond to climate change-related events.[61] Additionally, access to medical care, immigration status, and English proficiency are factors that measure a population's vulnerability to climate change-related events.[62] And as a result of the disproportionate impact of climate change in underserved communities, and the disproportionate pollution and social inequities already faced by these communities, certain populations are at an increased risk of experiencing adverse health effects. For example, low-income urban populations are more sensitive to climate change-related health risks due to pre-existing cardiovascular and respiratory conditions, "resulting in increases in illness, hospitalization, and premature death."[63]

2. Power plant impacts on communities with environmental justice concerns

Power plant emissions raise significant health concerns for underserved communities. Power plants emit many pollutants, including particulate matter, CO_2, mercury, as well as sulfur dioxide (SO_2) and nitrogen oxides (NOx), which contribute to the formation of ground-level ozone, smog, and fine particulate matter.[64] These power plant emissions are known to contribute to adverse health outcomes such as respiratory and cardiovascular diseases.[65] As EPA has recognized, underserved communities often bear a disproportionate burden of environmental harms and adverse health outcomes from these emissions, including "heart or lung diseases, such as asthma and bronchitis, increased susceptibility to respiratory and

---

[61] *Id.* at 4–7.

[62] *See* USGCRP Climate and Health Assessment at 252.

[63] *Id.* at 253.

[64] *See* EPA, *Clean Air Power Sector Programs: Power Plants and Neighboring Communities* (May 2023), https://www.epa.gov/power-sector/power-plants-and-neighboring-communities.

[65] *Id.*; *see also* Maninder P. S. Thind et al., *Fine Particulate Air Pollution from Electricity Generation in the US: Health Impacts by Race, Income, and Geography*, 53 Envtl. Sci. & Tech. 14,010, 14,010 (2019), DOI: 10.1021/acs.est.9b02527.

cardiac symptoms, greater numbers of emergency room visits and hospital admissions, and premature deaths."[66]

Power plants are also disproportionately located in proximity to underserved communities and have adverse health effects on their residents. For example, an analysis of the power plants in states belonging to the Regional Greenhouse Gas Initiative (RGGI) found that 42.6 percent of environmental justice communities host between two and five electric generating units, but only 28 percent of non-environmental justice communities host the same frequency range of these units.[67] Moreover, people living in poverty and communities of color are much more likely to live within six miles of a power plant than people not living in poverty and white communities."[68]

E. Section 111 of the Clean Air Act

Under the Clean Air Act, EPA establishes standards of performance to limit air pollution from new stationary sources under section 111(b) and issues emission guidelines that states use to establish standards for existing sources in the same industrial category under section 111(d). A "standard of performance" is a "standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements) the Administrator determines has been adequately demonstrated."[69] Standards set by EPA under section 111(b) are federally enforceable and apply to all new, modified, or reconstructed sources in that category.

Under section 111(d), "[t]he Agency, not the States, decides the amount of pollution reduction that ultimately must be achieved."[70] EPA does so by "determining, as when setting the new source rules," the best system of emission

---

[66] EPA, *Powerplants and Neighboring Communities*; *see also* EPA*, Climate Change, Health, & Environmental Justice*, *supra* n. 45; USGCRP, *Climate and Health Assessment* at 54–55.

[67] Juan Declet-Barreto & Andrew A. Rosenberg, Environmental Justice and Power Plant Emissions in the Regional Greenhouse Gas Initiative States at 11–12 (2022), https://doi.org/10.1371/journal.pone.0271026.

[68] *Id.*

[69] 42 U.S.C. § 7411(a)(1).

[70] *West Virginia v. EPA*, 142 S. Ct. 258, 2601–02 (2022).

reduction that has been adequately demonstrated for existing sources in that category.[71] "States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA."[72] Section 111(d) also directs EPA to allow states—in establishing a standard of performance for particular sources—to take into account a source's "remaining useful life and other factors."[73] In addition to issuing emissions guidelines that states use to establish standards for existing sources, EPA evaluates state plans to ensure that they are "satisfactory" in meeting the requirements of section 111(d).[74] If a state fails to submit a plan or EPA determines that a state plan is not satisfactory, EPA has the same authority to promulgate a federal plan to regulate the sources as it does in the state implementation plan context under section 110(c) of the Act.[75]

The definition of "standard of performance" under section 111(a)(1), which applies equally to standards set by EPA for new sources under section 111(b) and to state-established standards for existing sources under section 111(d), requires that standards be based on "adequately demonstrated" systems.[76] Although the statute does not define the term "adequately demonstrated," legislative history and court decisions provide some insight.

The legislative history to the 1970 Clean Air Act, which was when Congress added section 111, reveals that the phrase "adequately demonstrated" emerged from the conference committee that led to the final legislation. Congress substituted "adequately demonstrated" for the term "available," which the Senate and House bills had previously used.[77] The Senate and the House committee reports described "available" broadly, explaining that although an "available" technology "may not be one which constitutes a purely theoretical or experimental means of preventing or controlling air pollution,"[78] it need not "be in actual,

[71] *Id.*

[72] *Id.* (citations omitted).

[73] 42 U.S.C. § 7411(d)(1).

[74] *Id.* § 7411(d)(2).

[75] *Id.*

[76] *Id.* § 7411(a)(1).

[77] *See* H.R. Rep. No. 91-1783, at 9, 45 (1970) (Conf. Rep.); S. Rep. No. 91-1196, at 91 (1970); H.R. Rep. No. 91-1146, at 35 (1970).

[78] H.R. Rep. No. 91-1146, at 10 (1970).

routine use somewhere."[79] Although the reason for replacing "available" with "adequately demonstrated" in the final legislation is unclear, it seems unlikely that, given the House and Senate bills' agreement on this term, the conference committee intended to narrow the broad meaning of the former term by substituting the latter one without any discussion.

In its review of EPA's initial standards of performance under section 111(b), the D.C. Circuit reasoned that to be "adequately demonstrated," a system must be shown to be reasonably "reliable," "efficient," and "expected to serve the interests of pollution control without becoming exorbitantly costly."[80] Relatedly, an "achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not be routinely achieved within the industry prior to its adoption."[81]

Cases in which courts have interpreted the meaning of "adequately demonstrated" establish two basic principles: First, a technology or approach to reduce pollution need not be in wide use to be "adequately demonstrated." For example, in the 1973 *Essex Chemical* case, which involved challenges to new source standards for sulfuric acid plants, the court found the technology EPA determined to be the best system of emission reduction to be adequately demonstrated based on its use in one plant in the U.S. and several in Europe.[82] By contrast, the D.C. Circuit observed in *dicta* in its subsequent decision in *Sierra Club v. Costle* that the record would not have supported a determination by EPA that dry scrubbing was adequately demonstrated to control sulfur dioxide from coal-fired power plants

---

[79] S. Rep. No. 91-1196, at 16 (1970).

[80] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973); *see also Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (whether a system is adequately demonstrated "cannot be based on a 'crystal ball' inquiry.").

[81] *Essex Chem. Corp.*, 486 F.2d at 433–34.

[82] *Id.* at 435; *see also Bethlehem Steel Corp. v. EPA*, 651 F.2d 861, 873 (3d Cir. 1981) (construing "adequately demonstrated" in the context of delayed compliance orders under section 113 of the Act to preclude EPA reliance on "purely theoretical, experimental, or speculative technology." (citation omitted); *cf. Chemical Mfrs. Ass'n v. EPA*, 870 F.2d 177, 263 (5th Cir. 1989) ("Congress did not intend the [Clean Water Act's] term best available demonstrated control technology to limit treatment systems only to those widely in use in the industry.") (citing *American Iron and Steel Inst. v. EPA*, 526 F.2d 1027, 1058 (3d Cir. 1975) (internal quotations omitted).

where that approach was not yet in use at a power plant, and there had only been limited pilot-scale testing.[83]

The second principle to emerge from the caselaw is that adequate demonstration can be shown based on the use of a technology or approach in a separate industry similar to the source category being regulated in the rulemaking at issue. For example, in *Lignite Energy Council v. EPA*, the court upheld a performance standard for NOx emissions from industrial boilers that EPA had based on the application of pollution controls—selective catalytic reduction (SCR)—to utility boilers.[84] Rejecting petitioners' contention that SCR was not "adequately demonstrated" because EPA lacked emissions data from industrial boilers, the court reasoned "[u]tility and industrial boilers are similar in design and both categories of boilers can attain similar levels of NOx emissions reduction through combustion controls, which means that SCR will be required to capture comparable quantities of NOx for both boiler types."[85] The court also found relevant that the standard would apply to new boilers, and that it had previously recognized that section 111(b) "'looks towards what may fairly be projected for the regulated future, rather than the state of the art at present.'"[86] As long as EPA does not base its "adequately demonstrated" determination on mere speculation, it "may compensate for a shortage of data through the use of other qualitative methods, including the reasonable extrapolation of a technology's performance in other industries.[87]

F. Litigation Background

This section highlights two cases directly relevant to the Proposed Rule: the D.C. Circuit's decision in *American Lung Ass'n v. EPA*,[88] and the Supreme Court's subsequent decision in *West Virginia v. EPA*,[89] which reversed the D.C. Circuit in part.

American Lung Ass'n involved consolidated challenges by the Attorneys General, power companies, and environmental organizations to EPA's repeal of the

---

[83] *Sierra Club v. Costle*, 657 F.2d 298, 341, n.157 (D.C. Cir. 1981).

[84] *Lignite Energy Council v. EPA*,198 F.3d 930 (D.C. Cir. 1999).

[85] *Id.* at 933–34.

[86] *Id.* at 934 (quoting *Portland Cement*, 486 F.2d at 391).

[87] *Id.* (citation omitted).

[88] 985 F.3d 914 (D.C. Cir. 2021).

[89] 142 S. Ct. 2587 (2022).

Clean Power Plan—the Obama Administration's section 111(d) guidelines limiting greenhouse gas emissions from power plants—and its replacement, the Affordable Clean Energy (ACE) rule.

The D.C. Circuit granted the petitions for review, ruling that EPA's repeal of the Clean Power Plan was unlawful because it rested on the erroneous legal premise that the statutory text expressly foreclosed "generation shifting" measures (the ability of power plants to reduce emissions in the aggregate through a shift from higher carbon-emitting electricity generation to lower or zero carbon-emitting methods) as a system of emission reduction.[90] The court similarly rejected the ACE rule's prohibition on emissions trading and averaging because that prohibition was based on EPA's "flawed interpretation of the statute as unambiguously confined to measures taken 'at' individual plants."[91] In light of these rulings, the D.C. Circuit did not rule on our additional arguments for invalidating the ACE rule, *i.e.*, that EPA failed to weigh pollution reduction in choosing the best system of emission reduction and did not establish a minimum degree of emission limitation for state plans.

On appeal, the Supreme Court held 6–3 that EPA impermissibly considered generation shifting in determining the best system of emission reduction in the Clean Power Plan, thereby exceeding the agency's authority under section 111(d).[92] The Court reasoned that the Clean Power Plan's generation-shifting approach triggered the "major questions doctrine." In the majority's view, the Clean Power Plan was novel, was intended to restructure the nation's overall mix of electricity generation, represented a transformative expansion of EPA's authority, and resembled in key respects a program that Congress had considered and rejected multiple times.[93] And because it found that Congress had not clearly authorized EPA's consideration of generation shifting as a system of emission reduction, the Court concluded that EPA had exceeded its statutory authority in promulgating the Clean Power Plan.[94] Although the Court suggested that EPA's authority under section 111(d) may be limited to measures that would require regulated sources to operate more cleanly, it had "no occasion to decide whether the statutory phrase 'system of emission reduction' refers exclusively to measures that improve the

[90] 985 F.3d at 944–51.

[91] *Id.* at 957–58.

[92] *West Virginia*, 142 S. Ct. at 2610–16.

[93] *Id.* at 2610–14.

[94] *Id.* at 2614.

pollution performance of individual sources, such that all other actions are ineligible to qualify as the best system of emission reduction."[95] The Supreme Court accordingly reversed the D.C. Circuit's judgment in *American Lung Ass'n*.

Because the Supreme Court did not address the D.C. Circuit's holding that section 111 does not forbid emissions trading and averaging in state plans, or otherwise reject the D.C. Circuit's conclusion that "Section [1]11 itself does not textually restrict the States' choice of compliance measures for their sources at all," that holding continues in effect.[96]

On remand, the parties agreed, in light of EPA's announcement that it intended to replace the ACE rule, to have the case held in abeyance rather than have the D.C. Circuit adjudicate the petitioners' remaining challenges to the ACE rule. EPA subsequently extended the time period for state plan submittals on implementing the ACE rule until April 2024 and indicated that states will not need to meet this deadline if/when EPA replaces the ACE rule deadline in a new rule.[97]

G. Inflation Reduction Act

A few months after the *West Virginia* decision, Congress passed and President Biden signed into law the Inflation Reduction Act (IRA).[98] The Inflation Reduction Act affects the current rulemaking in two fundamental ways.

First, Congress has both confirmed EPA's authority to regulate greenhouse gases from power plants under the Clean Air Act and directed the agency to use that authority to ensure that the power sector cut carbon emissions. In adding the Low Emissions Electricity Program to the Clean Air Act, Congress included a definition of "greenhouse gas" as referring to "the air pollutants carbon dioxide, hydrofluorocarbons, methane, nitrous oxide, perfluorocarbons, and sulfur hexafluoride."[99] The law directs EPA to use its existing authorities—including section 111—to reduce carbon pollution from power plants. Congress directed EPA to assess within one year, *i.e.*, by August 15, 2023, the reductions in greenhouse gas emissions anticipated to occur from changes in domestic

---

[95] *Id.* at 2615.

[96] *See American Lung Ass'n*, 985 F.3d at 957–58.

[97] 88 Fed. Reg. 14,918, 14,919 (Mar. 10, 2023).

[98] Pub. L. No. 117-167, 136 Stat. 1366 (2022)

[99] 42 U.S.C. § 7435(c).

electricity generation and use on an annual basis through 2031.[100] The statute also appropriated $18 million to EPA "to ensure that reductions in greenhouse gas emissions are achieved through the use of the existing authorities of this Act, incorporating th[is] assessment."[101] According to the bill's lead sponsor in the House, Congressman Pallone, "Congress intends that EPA construe its authority under existing CAA authorities broadly, so EPA can promulgate impactful and innovative regulations, as appropriate."[102] Thus, Congress has given clear direction regarding the agency's authority and congressional intent that EPA use that authority to tackle carbon pollution from power plants.

Second, the Inflation Reduction Act's tax credits significantly changed the economics for two approaches to reducing power plant carbon pollution: carbon capture and sequestration (CCS) and co-firing with hydrogen. Congress's decision to invest heavily in tax credits to support these approaches informs EPA's consideration under section 111 of cost as a factor in determining the best system of emission reduction that has been adequately demonstrated. In addition, the extent of this investment indicates Congressional support for—and belief in the feasibility of—these technologies. As commentators have noted, "the funding provided by the IRA will allow EPA to increase the ambition of its CAA rulemakings, by lowering costs and demonstrating the feasibility of pollution control technologies."[103]

For example, regarding CCS, before the Inflation Reduction Act, the relevant federal tax credit (45Q) allocated $50/ton of CO_2 captured and stored, which often undervalued the costs of capture, transport, and storage. By increasing the value of the 45Q tax credit to $85/ton, the Inflation Reduction Act makes CCS at new and existing coal and gas plants more economic. For example, according to one recent analysis, the combined capture, transport, and storage costs for coal-fired and gas-fired power plants averages about $80–90/ton.[104] The report concludes that the increase in the 45Q tax credit to $85/ton makes carbon

---

[100] *Id.* § 7435(a)(5).

[101] *Id.* § 7435(a)(6).

[102] 168 Cong. Rec. E869 (Aug. 23, 2022).

[103] Greg Dotson and Dustin J. Maghamfar, "The Clean Air Act Amendments of 2022: Clean Air, Climate Change, and the Inflation Reduction Act," 53 ELR 10017, 10026 (Jan. 2023).

[104] Clean Air Task Force, "The Inflation Reduction Act creates a whole new market for carbon capture," (Aug. 22, 2022), https://www.catf.us/2022/08/the-inflation-reduction-act-creates-a-whole-new-market-for-carbon-capture/.

capture within the cost range for these plants (and other industries). As for co-firing hydrogen with natural gas, according to a recent analysis, "green hydrogen" has the potential to receive the greatest support, as electricity produced using it can simultaneously receive three tax incentives.[105] First, renewable facilities used to produce green hydrogen will be eligible for either the production tax credit or the investment tax credit, reducing production costs. Second, green hydrogen production facilities would qualify for the full value of the 45V hydrogen tax credit being zero emissions facilities. Third, electricity produced using green hydrogen would qualify for the production tax or investment tax credits. The combined effect of these incentives would reduce the levelized cost of energy of green hydrogen-fueled combined cycle generating turbines in 2030 by 52–67 percent relative to projects without incentives.

Impacts of the Inflation Reduction Act on the electricity generation mix are expected to be very significant, too. For example, in 2021, there were 210 coal plants in the continental U.S. providing 220 gigawatts of power capacity and 22 percent of total generation.[106] Before the Inflation Reduction Act was enacted, EPA expected coal-fired generation to drop to 131.7 gigawatts by 2028.[107] That was the baseline EPA used in its analysis that accompanied its proposed effluent limitation guidelines for coal-fired power plant water pollution in March 2023.[108] The revised projections for the power sector that reflect the new law show that EPA now expects coal to drop to 100 gigawatts of capacity by 2028 (about 100 plants) and provide about 11 percent of the nation's power.[109] By contrast, the expected impact of the Proposed Rule on generation mix is small. When EPA added the proposed limits for

---

[105] ICF, "How clean energy economics can benefit from the biggest climate law in U.S. history," (Sept. 16, 2022), https://www.icf.com/insights/energy/clean-energy-economic-benefits-us-climate-law.

[106] Jean Chemnick, "EPA: Climate law—not power plant rules—will reshape grid," *Climatewire* (May 17, 2023), E&E News | Article | EPA: Climate law — not power plant rules — will reshape grid (politicopro.com); *see* EPA, *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (May 2023) (RIA) at 2-6.

[107] Chemnick, *supra* n.122; *see* EPA, *Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Feb. 28, 2023) at 5-6.

[108] *Id.*

[109] *Id.*; *see* RIA at 3-27.

existing coal plants under section 111(d) to the modeling, for instance, those proposed limits further reduced coal generation capacity by only an additional 2 percent.[110] And while the Inflation Reduction Act is projected to reduce coal generation capacity in 2030 by 52 gigawatts, the Proposed Rule is predicted to decrease that capacity by 14 gigawatts.[111]

II. PROPOSED REPEAL OF THE ACE RULE

As part of the Proposed Rule, EPA proposes to formally repeal the ACE rule. EPA cites three grounds for repeal:

- As a policy matter, the best system of emission reduction in the ACE rule for coal-fired plants—heat rate improvements—is not an appropriate best system for these plants. Specifically, the heat rate improvements under the ACE rule "provide negligible CO_2 reductions at best and, in many cases, could increase CO_2 emissions because of the rebound effect."
- In the ACE rule, EPA had rejected CCS and natural gas co-firing as the best system for reasons that are no longer applicable.
- The ACE rule conflicts with section 111 of the Act and EPA's implementing regulations because it did not specifically identify the best system or the degree of emission limitation achievable through application of the best system.[112]

The Attorneys General support EPA's proposed repeal of the ACE rule and offer these comments on the three grounds cited by EPA for the repeal:

Heat rate improvements provide negligible emission reductions.

EPA proposes "as a policy matter" to repeal the ACE rule.[113] As EPA notes, heat rate improvements "achieve only limited GHG emission reductions."[114] When it promulgated the ACE rule, EPA acknowledged that the rule would only achieve about a 1 percent reduction in greenhouse gas emissions in 2030. Now, the agency

[110] *Id.*

[111] *Id.*

[112] 88 Fed. Reg. at 33,335–36.

[113] *Id.* at 33,335.

[114] *Id.* at 33,337.

"doubts that even these minimal reductions would be achieved."[115] EPA explains that an updated report on heat rate improvements that has superseded the study relied upon in the ACE rule concludes that heat rate improvements are less effective in reducing CO_2 emissions than previously assumed and that most sources have already optimized application of heat rate improvements. Furthermore, the ACE rule was projected to *increase* emissions in 15 states and the District of Columbia as a result of the "rebound effect," where a heat rate improvement results in greater utilization of a modified power plant, potentially overwhelming any emission reduction from a lower emission rate.[116] In light of these facts and the urgent need (discussed above) to substantially cut carbon pollution from the power sector, EPA's proposed repeal is on sound policy grounds.

In addition to representing a reasonable policy decision, repeal of the ACE rule is required under the Clean Air Act. As the D.C. Circuit has noted, "no sensible interpretation" of the best system of emission reduction would fail to incorporate "the amount of air pollution as a relevant factor to be weighed."[117] Yet, in the ACE rule, EPA did *not* weigh the amount of pollution reduction as a factor in choosing heat rate improvements as the best system. The agency did not, for example, compare anticipated pollution reductions from heat rate improvements with reductions from approaches that fit within its narrow interpretation of "system," such as CCS or co-firing with natural gas. Instead, EPA merely observed that "[i]mplementation of heat rate improvement measures would also achieve reasonable reductions in CO_2 emissions from designated facilities in light of the limited cost-effective and technically feasible emissions control opportunities."[118] Therefore, repeal of the ACE rule on the ground that the agency never weighed pollution reduction—even among those approaches that in the Trump EPA's view were systems under section 111—is also required under the Clean Air Act.

Relatedly, repeal of the ACE rule would remedy another legal defect: EPA's failure to explain its reversal in position that heat rate improvements "would not meet one of the considerations critical to the [best system] determination—the quantity of emission reductions."[119] Under the Supreme Court's decision in *FCC v.*

[115] *Id.*

[116] *Id.*

[117] *Sierra Club v. EPA*, 657 F.2d at 325–26.

[118] 84 Fed. Reg. 32,520, 32,542 (July 8, 2019).

[119] 80 Fed. Reg. at 64,727.

Fox Television Stations, Inc.,[120] an agency changing course must "provide a more detailed justification than would suffice for a new policy . . . when, for example, its new policy rests upon factual findings that contradict those which underlay its prior policy." In the ACE rule, EPA did not explain its reversal in position that heat rate improvements were not the best system because they did not satisfy the "critical" factor of pollution reduction.[121] By repealing the ACE rule, EPA would cure this legal defect as well.

The bases EPA cited in the ACE rule for rejecting CCS and natural gas co-firing as the best system no longer apply.

EPA further explains that the factual underpinnings of the ACE rule have changed in several ways, including the costs of reducing CO_2 emissions by using CCS or co-firing with natural gas. In the ACE rule, EPA justified its rejection of these two approaches as the best system of emission reduction on grounds that they would be too costly.[122] Four years later, the costs of natural gas co-firing have substantially decreased.[123] Similarly, as discussed above, the costs of CCS have substantially declined due to the Inflation Reduction Act's tax credit provisions as well as developments in the technology that have lowered capital costs. EPA concludes that CCS and natural gas co-firing are now cost reasonable, a factor that supports the agency's determination that these approaches constitute the best system for coal-fired power plants. We concur that the more favorable economic conditions of these approaches also support repeal of the ACE rule.

The ACE rule conflicts with section 111 by failing to identify the best system or specifying a degree of emission limitation from applying the best system.

As a third independent reason, EPA proposes to repeal the ACE rule on the ground that "the rule did not identify with sufficient specificity the [best system] or the degree of emission limitation achievable through the application of the [best

---

[120] *FCC v. Fox Television Stations, Inc.*,556 U.S. 502, 515–16 (2009).

[121] 80 Fed. Reg. at 64,727; *see also id.* (the amount of pollution reduced using heat rate improvements "is too small for these measures to be the [best system] by themselves for this source category," especially in light of "the magnitude of the environmental problem and projections by climate scientists that much larger emission reductions are needed from fossil fuel-fired [power plants] to address climate change.").

[122] *See* 84 Fed. Reg. at 32,545.

[123] 88 Fed. Reg. at 33,337.

system]."[124] Under section 111(d), it is EPA "not the States, [that] decides the amount of pollution reduction that ultimately must be achieved."[125] States then "submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA."[126] The ACE rule, however, merely identified a suite of heat rate improvements as "candidate technologies" without specifying "the degree of emission limitation States should apply in developing standards of performance for their sources."[127] As EPA acknowledges now, the ACE rule "shifted the responsibility for determining the [best system] and degree of emission limitation achievable from the EPA to the States," and therefore "did not meet the CAA section 111 requirement that the EPA determine the [best system] or the degree of emission limitation from application of the [best system]."[128] The Attorneys General agree that the ACE rule should be repealed because it is fundamentally inconsistent with the structure of section 111(d) and the respective roles of EPA and the states as recognized by the Supreme Court in *West Virginia*.

EPA cites two defects related to the lack of a specific emission limitation that warrant repeal of the ACE rule. As the agency explains, the ACE rule's failure to specify a degree of emission limitation for state plans would turn EPA's evaluation into whether state plans are "satisfactory" into a "standardless exercise."[129] Under section 111(d), Congress assigned EPA a supervisory role to ensure state plans contain standards of performance for existing sources that are "satisfactory."[130] EPA has the authority and the responsibility to set criteria for evaluating the standards of performance proposed in state plans. Section 111(d)(1) makes clear that states are required to "establish standards of performance" for existing sources that reflect the degree of emission reduction achievable through application of the best system of emission reduction that EPA determines is adequately demonstrated.[131] Similarly, EPA must have some objective criteria to determine whether state plans

[124] *Id*. at 33,338.

[125] *West Virginia v. EPA*, 142 S. Ct. at 2602.

[126] *Id.*

[127] 88 Fed. Reg. at 33,338.

[128] *Id.* at 33,339.

[129] *Id.*

[130] 42 U.S.C. § 7411(d)(1), (2)(A).

[131] *Id*. § 7411(a)(1).

are "satisfactory."[132] EPA considered whether a substantive emissions limitation was necessary in its original adoption of the implementing regulations, finding that "it seems clear that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also [EPA's] review of state plans."[133] The ACE rule's approach of having states evaluate the feasibility of heat rate improvements at power plants—without requiring imposition of any minimum emissions limit—would have resulted in no "substantive criterion" for EPA to use in evaluating state plans. As EPA notes, the one state that submitted a (partial) state plan to implement the ACE rule would have established a standard of performance "that was higher (*i.e.*, less stringent) than the source's historical emission rate."[134]

The lack of a federal emissions limitation in the ACE rule not only created uncertainty for EPA evaluations, the rule created uncertainty for states in developing their own emissions limitations, leading to uncertainty for their regulated sources. The lack of a federal numerical emissions limitation would also have left state plans vulnerable to challenge on the basis that they did not establish a performance standard reflective of the emissions limitation achievable from application of the best system of emission reduction that EPA has chosen, and would have complicated judicial review of state plans.[135]

And by proposing to allow states to set individualized standards of performance under section 111(d) without EPA establishing any overall statewide numerical emissions limits, the agency would also undermine national uniformity and create incentives for a "race to the bottom," encouraging states to outcompete each other for new industry. Congress sought to avoid this very situation in the Clean Air Act Amendments of 1970, where it expressed concerns with "efforts on the part of States to compete with each other in trying to attract new plants and facilities without assuring adequate control of extra-hazardous or large-scale emissions therefrom."[136]

The second related defect EPA identifies is that it failed in the ACE rule to justify its departure from previous section 111(d) rules that always included a

---

[132] *Id.* § 7411(d)(2).

[133] 40 Fed. Reg. at 53,342.

[134] 88 Fed. Reg. at 33,337 (citing partial plan submitted by West Virginia).

[135] *See* 42 U.S.C. § 7607(b)(1).

[136] H. Rep. No. 91-1146, Reporting on H.R. 17255, p. 893 (Jun. 3, 1970), *reprinted in* 1970 U.S.C.C.A.N 5356, 5358.

numeric degree of emissions limitation, in violation of *FCC v. Fox Television*.[137] As EPA notes, prior to the ACE rule, the agency consistently required a numerical emissions limitation in its emission guidelines. To reverse this longstanding policy, EPA was required to address the multiple reasons it adopted this requirement in 1975 and explain why the facts and circumstances no longer justify this approach. Instead, in the ACE rule EPA offered only a short and deeply-flawed legal analysis of why it believed that a numerical emissions limitation was no longer required.[138] Where an agency changes a decades-old regulation on which states and regulated entities have come to rely, it must provide a "more detailed justification than what would suffice for a new policy created on a blank slate."[139] EPA did not meet that significant burden, providing another ground for the ACE rule's repeal.

EPA has multiple, strong legal and factual grounds for repealing ACE.

III. EPA'S PROPOSED PERFORMANCE STANDARDS FOR NEW GAS TURBINES AND EMISSION LIMITS FOR EXISTING UNITS

In 2015, EPA issued new source performance standards to limit emissions of carbon dioxide from three subcategories of new and reconstructed stationary combustion turbines: base load electrical generating units, non-base load natural gas-fired units, and non-base load multifuel-fired (*i.e.*, non-natural gas-fired) units.[140] Since then, the technology has improved with respect to achievable emission reductions and new gas-fired plants continue to be built as both base load generation and non-base load generation to support intermittent renewable energy sources such as solar and wind. Indeed, power generation from natural gas-fired combustion turbines is projected to increase as more coal-fired electrical generating units retire and new combustion turbines are added to the grid. By 2050, 309 gigawatts of new natural-gas fired capacity is expected to come online, and by 2035, CO_2 emissions from natural gas-fired units is projected to reach 527 million metric tons.[141]

To address the projected growth in the natural-gas power sector and the sector's associated greenhouse gas emissions, EPA is proposing to revise the 2015

[137] 88 Fed. Reg. at 33,339 (citing 556 U.S. 502)).

[138] *See* 83 Fed. Reg. at 44,771.

[139] *Fox Television*, 556 U.S. at 515.

[140] 80 Fed. Reg. 64,510 (Oct. 23, 2015).

[141] 88 Fed. Reg. at 33,265.

new source performance standard and is proposing emission guidelines for existing natural gas-fired combustion turbines. In the Proposed Rule, EPA has created subcategories based on the "capacity factor" of the combustion turbine, *i.e.*, the percentage of its full generating capacity that the turbine is expected to use. The low load ("peaking units") subcategory consists of combustion turbines with a capacity factor of less than 20 percent, which are used mainly as reserves during peak demand.[142] The intermediate load subcategory consists of combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound based on design efficiency.[143] The base load subcategory consists of combustion turbines that operate above the upper-bound threshold for intermediate load turbines and supply electricity to the grid more or less constantly.[144] EPA has identified the best system of emission reduction for each subcategory, including CCS and mixing cleaner fuels into existing fossil fuels (co-firing). The Proposed Rule sets emission standards based on the emission levels that would be achievable using CCS or co-firing, but does not require facilities or states to use these specific emission-control strategies.

As detailed below, the Attorneys General support EPA's proposed new source performance standards for low load, intermediate load, and base load combustion turbines as consistent with the statutory command of section 111 of the Clean Air Act. Likewise, we support EPA's proposed emission guidelines for base load combustion turbines. Within each subcategory, the proposed standards and emission guidelines reflect the application of the best system of emission reduction that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated. For low load combustion turbines, we encourage EPA to promptly supplement these guidelines with a proposal for existing peaker plants, which remain unregulated for greenhouse gases under the proposal, and to consider whether stronger standards can be adopted for new plants. For base load combustion turbines, we encourage EPA to identify one system as the *best* system of emission reduction based on EPA's balance of the cost of the reductions, non-air quality health and environmental impacts, and energy requirements.[145] We also urge EPA to strengthen the Proposed Rule by expanding regulation of existing

[142] *Id.* at 33,244.

[143] *Id.*

[144] *Id.*

[145] *See* 42 U.S.C. § 7411(a)(1); *Sierra Club v. Costle*, 657 F.2d at 326, 330.

natural gas-fired combustion turbines in order to protect against climate change and other public health impacts of natural gas combustion.

A. EPA Should Promptly Commence a Supplemental Rulemaking to Address Existing Peaking Units

Low-capacity factor electricity generating units, *i.e.*, "peaking units" or "peakers," raise significant environmental justice and climate concerns not addressed by the Proposed Rule. As the Clean Energy Group recently found, peakers contribute to climate change, emitting an average of 60 million tons of CO_2 each year.[146] And, importantly, they contribute significantly to local air pollution. Over 4.4 million people in urban areas are currently living within one mile of a peaker, and almost 32 million people are living within three miles of one.[147] Peakers are disproportionately located in low-income communities and communities of color.[148] And these plants can also be less efficient and more polluting than baseload units, with disproportionate emissions of $PM_{2.5}$, as well as NOx and SO_2, which contribute to the formation of ground-level ozone and $PM_{2.5}$.[149]

These impacts are of substantial concern to many of our states, where existing peaking units contribute to local air pollution, often in underserved communities. For example, according to the Clean Energy Group's analysis, the 20 peakers in Boston's Metropolitan Area run more than the national average and contribute an annual average of 544,500 pounds of NOx and 63,000 pounds of SO_2 to the city's local pollutants.[150] About 256,000 people live within one mile of these units, and 1.45 million people live within 3 miles of one.[151] In New York City,

---

[146] Clean Energy Group & Stratagen, The Peaker Problem (July 2022), at 13.

[147] *Id.* at 17.

[148] *Id.* at 8. In its analysis, the Clean Energy Group defines peakers as all operating plants running on oil or gas turbines with a minimum generating capacity of 10 MW and a maximum capacity factor of 15 percent. *Id.* at 11.

[149] *Id.* at 8. In absolute terms, peaking units are estimated to contribute 46,000 U.S. tons of NOx and 7,700 tons of SO_2 every year. *Id.* at 12–13; *see also* Ozone Transport Commission (OTC) Stationary and Area Source Committee, High Electric Demand Days (HEDD) Workgroup, White Paper: Examining the Air Quality Effects of Small EGUs, Behind the Meter Generators, and Peaking Units during High Electric Demand Days (Nov. 10, 2016), at 4, 25–40 (describing peaker NOx emissions impacts on high electric demand days).

[150] *Id.* at 21.

[151] *Id.*

750,000 people live within one mile of a peaker plant, 78 percent of whom are either low income or people of color.[152]

Accordingly, while the Proposed Rule does not address existing peaking units, EPA should take prompt action in a subsequent rulemaking to identify a best system of emission reduction and issue emission guidelines for these sources.

B. EPA's Should Consider Strengthening its Proposal for New and Reconstructed Peaking Units

For new and reconstructed peaking units, EPA is proposing that the best system of emission reduction is the use of lower-emitting fuels (*e.g.*, natural gas and distillate oil) with standards of performance ranging from 120 pounds of CO_2 per one million British thermal units (lb CO_2/MMBtu) to 160 lb CO_2/MMBtu depending on the type of fuel used.[153] EPA's proposed best system, which is the same as for the non-base load subcategory in the 2015 rule, is technically feasible and adequately demonstrated.[154] Because of the variability in the operation of low load combustion turbines with multiple starts and stops, EPA has determined that the use of lower emitting fuels is the best system and the associated standard of performance should be based on heat input.

Since 2015, all newly-constructed low load simple cycle turbines have been subject to this standard; therefore, a best system based on the use of lower-emitting fuels would have minimal costs to affected facilities and continue to control these sources' emissions by limiting the use of fuels with higher carbon content. However, given the substantial impact of peaking units – including new and reconstructed peaking units – on the surrounding communities, EPA should consider whether stronger standards of performance are achievable and warranted.

[152] The PEAK Coalition, The Fossil Fuel End Game: A Frontline Vision to Retire New York City's Peaker Plants by 2030 at 13 (Mar. 2021), https://www.cleanegroup.org/wp-content/uploads/Fossil-Fuel-End-Game.pdf.

[153] 88 Fed. Reg. at 33,244.

[154] Although the BSER for this subcategory is the same, EPA's proposed definition of the low load subcategory is narrower as compared to the electric sales threshold for non-base load combustion turbines in the 2015 NSPS. *See* 88 Fed. Reg. at 33,284.

C. EPA's Proposed Best System for New and Reconstructed Intermediate Load Natural Gas Combustion Turbine Units Is Adequately Demonstrated.

For the intermediate load subcategory, EPA is proposing two components for the best system of emission reduction and the associated standard of performance applies in phases: the first component of the best system is highly efficient simple cycle generation, and the second component is 30 percent by volume low-greenhouse gas hydrogen co-firing.[155] EPA's proposed standard of performance for the first phase—based on application of high efficiency simple cycle turbine technology—is 1,150 lb CO_2/MWh-gross based, which affected facilities must meet upon promulgation of the final rule.[156] EPA's proposed standard of performance for the second phase—based on continued application of highly efficient generation and co-firing of 30 percent by volume low-greenhouse gas hydrogen—is 1,000 lb CO_2/MWh-gross, which affected facilities must meet by 2032.[157]

With respect to the first component, EPA's proposed best system of highly efficient simple cycle generation is adequately demonstrated. As EPA notes, highly efficient simple cycle designs have been demonstrated by facilities for decades and the proposed levels of efficiency have been achieved by many recently constructed turbines, both simple cycle and combined cycle combustion turbines.[158] With respect to the second component, the technology that sources would use to implement low-greenhouse gas hydrogen co-firing is also adequately demonstrated. The use of byproduct fuels containing large percentages of hydrogen is well-established, and most combustion turbines currently used for electricity generation can burn hydrogen blends of 5–10 percent by volume, with blends as high as 20–30 percent

[155] 88 Fed. Reg. at 33,244. "Low-GHG hydrogen" is defined as "hydrogen (or a hydrogen derived fuel such as ammonia) produced through a process that results in a well-to-gate GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen produced (kg CO_2e/kg H2), determined using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (GREET model)." Proposed Regulatory Text, 40 C.F.R. § 60.5580a.

[156] 88 Fed. Reg. at 33,244.

[157] *Id.*

[158] *See id.* at 33,287 ("Approximately 14 percent of simple cycle and combined cycle combustion turbines that have commenced operation since 2015 have maintained emission rates below the proposed standards, demonstrating that . . . this BSER is commercially available and that the standards of performance [are] achievable.")

by volume being used in certain situations.[159] Indeed, many models of new utility combustion turbines have demonstrated the ability to co-fire up to 30 percent hydrogen and developers are working toward models that will be ready to combust 100 percent hydrogen by 2030.[160] Some of these projects include:

- Los Angeles Department of Water and Power's Scattergood Modernization Project, which is converting its gas-fired power plant to run on 100 percent electrolytic hydrogen by 2035;

- The Brentwood Power Station (simple cycle turbine) and Cricket Valley Energy Center (combined cycle facility) in New York, which intend to utilize hydrogen blends ranging from 5 to 30 percent;

- Intermountain Power Authority's project in Utah, which is studying the integration of large-scale hydrogen production and storage, with the goal of combusting 30 percent hydrogen by 2025 and 100 percent hydrogen by 2045;

- The Long Ridge Energy Generation Project in Ohio, which is planning to blend 15 to 20 percent hydrogen before a turbine modification is necessary for the plant to combust 100 percent hydrogen;

- Northern California Power Authority's project at Lodi Energy Center, which has already installed a turbine capable of using up to 45 percent hydrogen;[161] and

- San Diego Gas & Electric's Palomar Energy Center, which plans to blend a small amount of low-carbon hydrogen starting this year.[162]

The feasibility challenges associated with low-greenhouse gas hydrogen co-firing are primarily a matter of whether a sufficiently developed industry and infrastructure for the production and delivery of low-greenhouse gas hydrogen will

---

[159] *See id.* at 33,305.

[160] *Id.* at 33,255.

[161] NCPA, "NCPA's Green Hydrogen Future" http://www.ncpa.com/wp-content/uploads/2021/10/NCPAs-Green-Hydrogen-Future-Position-Paper.pdf .

[162] SDGE, "Hydrogen Innovations," https://www.sdge.com/more-information/environment/sustainability-approach/hydrogen-innovation.

be available to sources. Given the significant technological developments and federal incentives to grow the hydrogen sector—specifically low-greenhouse gas hydrogen—EPA's projection that an adequate supply of low-greenhouse gas hydrogen will be available for combustion turbines by 2032 is reasonable. The Department of Energy is working to create the regional markets necessary for the production of low-greenhouse gas hydrogen through DOE's $8 billion Regional Clean Hydrogen Hub Program, $500 million Clean Hydrogen Manufacturing and Recycling Program, and $1 billion Clean Hydrogen Electrolysis Program authorized by the Infrastructure Investment and Jobs Act of 2021.[163] In addition, as discussed above (*see infra* Section I.G.), the Inflation Reduction Act authorizes a multi-tier hydrogen production tax credit that awards the highest amount of tax credits to the hydrogen production processes with the lowest estimated greenhouse gas emissions (0.45 kg CO_2e/kgH2 or less) from well to gate.[164] Indeed, the extraordinary investment Congress has made in low-greenhouse gas hydrogen across the Infrastructure Investment and Jobs Act and the Inflation Reduction Act is plainly intended to bring the hydrogen sector into a state of maturity consistent with the courts' criteria for adequate demonstration, such as reliability, efficiency, and cost-effectiveness.[165] These federal incentives would provide the greatest support for the proposed standards if the Department of the Treasury's forthcoming guidance on the hydrogen tax credit, DOE's program criteria, and EPA's criteria for low greenhouse gas-hydrogen are aligned as much as possible.

In evaluating whether a system of emission reduction is the "best" adequately demonstrated system under section 111, EPA must consider its *overall* emissions reductions. It would be untenable to identify as the "best system of emission reduction" one that produces an equal or greater quantity of upstream emissions as it reduces at the sources.[166] Accordingly, we support EPA's proposed standard of performance reflecting the application of co-firing with *low*-greenhouse gas hydrogen. Here, EPA appropriately acknowledges the importance of how hydrogen is produced and the *net* greenhouse gas emission reductions associated with using

---

[163] *Id*. at 33,310.

[164] *Id.* at 33,261.

[165] *See Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d at 433.

[166] *See Sierra Club v. Costle*, 657 F.2d at 326 ("[W]e can think of no sensible interpretation of the statutory words 'best . . . system' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions"); *Portland Cement Ass'n*, 465 F.2d at 385, n.42 (supporting EPA's holistic consideration of environmental impacts of pollution control equipment and stating that "[t]he standard of the 'best system' is comprehensive").

hydrogen as a fuel. Specifically, EPA determined that "[c]o-firing hydrogen at combustion turbines when that hydrogen is produced with large amounts of GHG emissions would ultimately result in increasing overall GHG emissions, compared to combusting solely natural gas at the combustion turbine."[167] A standard of performance that allows sources to burn high-greenhouse gas hydrogen to comply with the proposed standard would accordingly not "reflect[] the degree of emission reduction achievable through application of the [BSER]."[168] EPA's proposal to base the standard of performance on co-firing with low-greenhouse gas hydrogen also represents the reasoned decision-making required by agencies when enacting regulations.[169] Burning high-greenhouse gas hydrogen to meet EPA's proposed standard would result in an overall increase in greenhouse gas emissions, thereby "ignor[ing] an important aspect of the problem" being addressed by the Proposed Rule: the reduction of greenhouse gas emissions from the intermediate load subcategory's operations.[170] In that regard, EPA should consider a separate rulemaking under section 111 to determine whether to list hydrogen production as a source category and whether to set standards that limit greenhouse gas emissions from the hydrogen production process.

Even low-greenhouse gas hydrogen co-firing has its drawbacks, including the environmental justice concerns discussed *infra* in Part V, as well as potential inefficiency. Outside those situations where low-greenhouse gas hydrogen production is used as a strategy to store surplus renewable-generated electricity,[171] it is plainly more efficient and environmentally sound to use renewable electricity to serve demand in lieu of a combustion turbine rather than produce a co-firing fuel for that turbine. We recognize that the Supreme Court's decision in *West Virginia v.*

---

[167] 88 Fed. Reg. at 33,315.

[168] 42 U.S.C. § 7411(a)(1).

[169] *See Motor Vehicles Mfrs. Ass'n v. State Farm Auto Ins Co.*, 463 U.S. 29, 43 (1983) (an agency engaged in reasoned decision making may not ignore "an important aspect of the problem.").

[170] EPA correctly notes the importance of avoiding upstream methane emissions in lowering the impact of natural gas combustion turbines. Although it is not clear how EPA will factor upstream methane emissions in the context of limiting greenhouse gases from combustion turbines, we support EPA's consideration and encourage EPA to review the recent studies that illustrate the historical underestimation of the actual levels of methane emissions.

[171] 88 Fed. Reg. at 33,306; *see* Intl. Energy Ass'n, *The Future of Hydrogen*, at 150–65 (June 2019), https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf.

EPA precludes EPA from recognizing generation-shifting as the best system of emission reduction, however.[172] And in that light, we agree low-greenhouse gas hydrogen co-firing is the "best" out of the systems EPA is legally permitted to consider. But the constrained nature of that exercise is further reason to ensure that states retain flexibility to secure equivalent or greater emission reductions through their innovative policies and strategies, even under the new source performance standards program.

D. EPA Should Strengthen its Proposal for New and Existing Base Load Natural Gas Combustion Turbines.

The Attorneys General support EPA's proposal to curb greenhouse gas emissions from base load natural gas electrical generating units but have identified ways to strengthen this proposal, while respecting the important role these sources currently play in supplying power. First, we encourage EPA to identify a single system as the *best* system of emission reduction, while preserving viable compliance pathways based on CCS and low-greenhouse gas hydrogen co-firing. Second, we urge EPA to expand regulation of existing natural gas-fired combustion turbines in order to protect against climate change and other public health impacts of natural gas combustion.

For new and reconstructed combustion turbines, the base load subcategory consists of natural gas combined cycle units with a capacity factor of more than 50 percent. These units supply electricity to the grid more or less constantly. EPA is proposing an approach in which the best system of emission reduction for the base load category has two best system pathways: one that is based on the use of CCS at a capture rate of 90 percent and a separate one based upon co-firing with low-greenhouse gas hydrogen. Similar to the intermediate load subcategory, the associated standard of performance applies in multiple phases.

For these base load combustion turbines, EPA's proposed standard of performance for the first phase—based on highly efficient generation—is 770 lb CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or more, and 770 lb to 900 lb CO_2/MWh-gross for units with a base load rating of less than 2,000 MMBtu/h.[173] All affected facilities—those that commence construction after the date the Proposed Rule was published in the Federal Register—would have to meet the first phase of the standard of performance based on highly efficient

[172] 142 S. Ct. at 2616.

[173] 88 Fed. Reg. at 33,244.

generation.[174] At the second phase of the standards, the two pathways emerge. First, for the co-firing with hydrogen pathway, EPA's proposed standard, based on co-firing with 30 percent by volume low-greenhouse gas hydrogen, is 680 lb CO_2/MWh-gross, which affected facilities must meet by 2032.[175] Second, for the CCS pathway, EPA's proposed standard, based on installation of a CCS system that achieves 90 percent capture of greenhouse gas emissions, is 90 lb CO_2/MWh-gross, which affected facilities would have to meet by 2035.[176] Facilities that choose the co-firing with hydrogen pathway have a third phase: by 2038, they must achieve a standard of 90 lb CO_2/MWh-gross, which is based on co-firing with low-greenhouse gas hydrogen at 96 percent.[177]

For existing combustion turbines, EPA is proposing to issue emission guidelines only for large units over 300 megawatts with a capacity factor greater than 50 percent.[178] Given the similarities between new and existing base load combustion turbines, EPA is proposing a best system for existing base load natural gas combustion turbines that is the same as the second phase of requirements for new and reconstructed base load combustion turbines. Thus, EPA is proposing emission guidelines that require either that these sources achieve a degree of emission limitation reflecting the utilization of 30 percent by volume low-greenhouse gas hydrogen co-firing by 2032 (increasing to 96 percent in 2038) or the use of a CCS system that achieves 90 percent capture of CO_2 emissions by 2035.[179]

1. EPA's proposed best system for new and existing base load gas-fired combustion turbines is adequately demonstrated, but EPA should consider finalizing a single best system of emission reduction.

EPA's proposed first component best system of emission reduction and associated standard of performance for new and reconstructed base load combustion turbines—based on highly efficient generation—is both adequately demonstrated and well supported in the record. EPA has long recognized that combustion turbines can be designed to limit greenhouse gas emissions rates through improving heat rate

[174] *Id.*

[175] *Id.* at 33,244–45.

[176] *Id.*

[177] *Id.*

[178] *Id.* at 33,245.

[179] *Id.* at 33,361.

(efficiency) and thereby reducing fuel usage per megawatt hour. A review of recent determinations in the agency's RACT/BACT/LAER online database shows that more than three dozen permits have been issued for baseload gas combustion turbines since 2014 with emission limits below the current new source performance standard of 1,000 lb. CO_2/MHw-gross.[180] These results demonstrate that increased efficiency through design improvements warrant strengthening of the current standard for baseload combustion turbines. Indeed, since 2012, New York has had in place a more stringent performance standard for new and modified combined cycle combustion turbines of 925 lb CO_2/MWh-gross.[181]

With respect to the second component best system for new and reconstructed base load combustion turbines, as well as the best system for existing base load turbines, we urge EPA to identify one system as the *best* adequately demonstrated system of emission reductions based on EPA's balance of the cost of the reductions, non-air quality health and environmental impacts, and energy requirements.[182] We further urge EPA to identify a single standard of performance—with phased stringency as necessary—based on EPA's determination of that best system of emission reduction. The adequate demonstration of low-greenhouse gas hydrogen is discussed *supra* in Section III.C; below, we discuss CCS's demonstration as a system of emission reduction for base load combustion turbines.

Natural gas-fired combustion turbines can be built and retrofitted with CCS and can play a valuable role in a decarbonized grid by providing clean power when required. Although most CCS projects to date have been at coal-fired steam generating units, the core technology of CO_2 capture applied to combustion turbines is similar to that of coal-fired generating units (both may use amine solvent-based methods).[183] For example, the Bellingham power plant in Massachusetts was a 40-megawatt combined cycle combustion turbine that operated from 1991–2005 and captured 85–95 percent of CO_2 in the slipstream for use in the food industry.[184] The deployment of CCS at the Bellingham power plant demonstrates that CCS can be successfully applied to combined cycle turbines.

---

[180] *See* EPA, RACT/BACT/LAER Clearinghouse, RBLC Greenhouse Gas Search (Utilities, Fossil Fuel Electric Power Generation), https://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults.

[181] 6 N.Y. Comp. Codes R. & Regs. Tit. 6, § 251.3(a)(1).

[182] *See* 42 U.S.C. § 7411(a)(1); *Sierra Club v. Costle*, 657 F.2d at 326, 330.

[183] *See* 88 Fed. Reg. at 33,291.

[184] *Id.* at 33,292.

Along with the Bellingham plant, there are several DOE-funded projects in progress at natural gas combustion turbines in the U.S. that will use carbon capture designed to capture 95–97 percent of CO_2 emissions.[185] In 2022, DOE announced up to $189 million in funding for integrated Front-End Engineering Design (FEED) studies to support the development of community-informed integrated CCS projects.[186] Recent CCS FEED studies at natural gas combined cycle plants either underway or selected for award negotiations include:

- Duke Energy's proposed CCS project at an integrated gasification combined cycle facility in Edwardsport, Indiana,[187]
- Entergy Services, LLC's proposed CCS project for the Lake Charles Power Station using post-combustion CO_2 capture technology and a pipeline to transport the captured CO_2 for sequestration,[188]
- Taft Carbon Capture, LLC's proposed carbon capture facility for the existing Taft cogeneration power plant facility in Hahnville, Louisiana,[189]
- Tampa Electric Company's proposed post-combustion CO_2 capture technology with transport and secure geologic sequestration for the existing natural gas combined cycle power plant at the Polk Power Station in Mulberry, Florida,[190]
- Elk Hills power plant in Kern County, California,[191]
- Mustang Station in Texas,[192]
- Southern Company in Mississippi or Alabama,[193]

---

[185] *Id.* at 33,293.

[186] DOE, "Carbon Capture Demonstration Projects Program FEED Studies Selections for Award Negotiations," https://www.energy.gov/oced/carbon-capture-demonstration-projects-program-front-end-engineering-design-feed-studies.

[187] *Id.*

[188] *Id.*

[189] *Id.*

[190] *Id.*

[191] DOE, "FOA 2058: Front-End Engineering Design Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants," https://www.energy.gov/fecm/foa-2058-front-end-engineering-design-feed-studies- carbon-capture-systems-coal-and-natural-gas.

[192] *Id.*

[193] *Id.*

- Calpine's Delta Energy Center in California,[194]
- Calpine Baytown combined heat and power in Texas,[195]
- Calpine Deer Park Energy Center in Texas,[196]
- Coyote Energy Center (NET Power) in Colorado,[197]
- Broadwing Energy (NET Power) in Illinois,[198] and
- Chevron Eastridge Cogeneration plant in California.[199]

Several demonstration CCS natural gas projects further support EPA's determination that CCS is adequately demonstrated. In July 2023, Calpine Corp. announced the first pilot CCS project in California on a natural gas plant near Los Medanos Energy Center.[200] The pilot will use solvent-based technology to reduce CO_2 emissions by more than 95 percent and is expected to be done by mid-August of this year.[201] Calpine is also assessing CCS projects at the Sutter Energy Center in California and at two natural gas projects in Texas.[202] NET Power, LLC, is working to build a utility-scale gas power plant with near zero emissions in Texas's Ector County,[203] and Competitive Power Ventures Inc. has a planned facility in West

---

[194] Calpine, "Our CCS Projects," https://calpinecarboncapture.com

[195] *Id.*

[196] *Id.*

[197] Sonal Patel, "8 Rivers Unveils 560 MW of Allam Cycle Gas-Fired Projects for Colorado, Illinois." *Power* (Apr. 15, 2021), https://www.powermag.com/8-rivers-unveils-560-mw-of-allam-cycle-gas-fired-projects-for-colorado- illinois/.

[198] Broadwing Energy, "Broadwing Clean Energy Complex," https://broadwing.energy/.

[199] Chevron, Press Release, "Chevron Launches Carbon Capture and Storage Project in San Joaquin Valley," (May 18, 2022), https://chevroncorp.gcs-web.com/news-releases/news-release-details/chevron-launches-carbon-capture-and- storage-project-san-joaquin.

[200] Energywire, "Power Company Eyes First CCS Plant In California, (July 14, 2023) https://subscriber.politicopro.com/article/eenews/2023/07/14/power-company-eyes-first-gas-ccs-plant-in-california-00106112.

[201] *Id.*

[202] *Id.*

[203] E&E News, "Texas Company set to build first big CCS gas power plant," (Apr. 12, 2023), https://subscriber.politicopro.com/article/eenews/2023/04/12/net-power-and-zachry-group-00091419.

Virginia.[204] Federal funding of CCS natural gas technologies, transport, and sequestration as well as federal policies such as the Inflation Reduction Act's newly expanded tax credit for CCS under Internal Revenue Code section 45Q will further reduce the cost of implementing CCS and will support the deployment of CCS at the national level.

For these reasons, as well as the significant emission reduction achieved by CCS, the reasonable cost of achieving such reduction, and the non-air quality health and environmental impact and energy requirements, the record would support EPA finding that CCS at a capture rate of 90 percent is the best system of emission reduction that has been adequately demonstrated for base load natural gas-fired combustion turbines. However, EPA is correct to note the significant investment in low-greenhouse gas hydrogen as an emission reduction system by industry, states, federal agencies, and Congress,[205] which favors preserving low-greenhouse gas hydrogen as a viable compliance pathway even under standards of performance and emission guidelines based on a CCS "best system." To that end, EPA should consider setting a compliance date of 2038 for the 90 lb CO_2/MWh-gross standard of performance, even if it identifies 90 percent CCS as "best," to allow states and utilities that have invested heavily in low-greenhouse gas hydrogen to leverage those investments in compliance. Although this adjustment could sacrifice emission reductions that would otherwise be achieved in 2035-2038, EPA may be able to recoup or surpass any foregone reductions by making the further adjustments we urge below to the coverage of its proposal for existing gas-fired sources.

2. EPA should broaden the Proposed Rule's coverage of existing natural gas-fired sources.

Under the Proposed Rule, EPA is proposing emission guidelines for large (*i.e.*, greater than 300 megawatt), frequently operated (*i.e.*, with a capacity factor of greater than 50 percent), existing gas-fired combustion turbines. The Proposed Rule only covers about 25 percent of the emissions from these sources; therefore, EPA is soliciting comments on whether the capacity factor threshold or capacity threshold should be lowered to cover more existing natural gas-fired turbines. For example, a 40 percent capacity factor and 100 megawatt capacity would cover 75 percent of

[204] Energywire, "Climate law spurs CCS at new West Virginia gas plant" (Sept. 19, 2022), https://subscriber.politicopro.com/article/eenews/2022/09/19/climate-law-spurs-new-west-virginia-gas-plant-with-ccs-00057278.

[205] 88 Fed. Reg. at 33,305–06, 33,312–13.

emissions from existing gas-fired combustion turbines, but may also require substantial infrastructure build out.

Alternatively, EPA stated in its recent supplemental modeling analysis that it is evaluating whether to apply the threshold based on the total capacity of the plant rather than based on the capacity of the unit.[206] Based on a recent analysis of this approach, a plant-based CCS standard could increase emissions coverage by over 60 percent while leaving the total number of existing gas-fired plants subject to the proposed emission guidelines essentially unchanged.[207]

We support EPA's consideration of this issue and recommend that EPA decrease the capacity and capacity factor thresholds to a level that is achievable, taking into account cost and feasibility considerations. We further encourage EPA to continue its evaluation of whether a plant-based standard is appropriate. To the extent greater coverage in the proposed guidelines for existing gas-fired sources is feasible, the additional emission reductions secured will provide crucial mitigation for the climate crisis and promote the objectives of section 111.

IV. EPA'S PROPOSED EMISSION GUIDELINES FOR EXISTING COAL-FIRED PLANTS

The Proposed Rule also contains proposed emission guidelines for states to regulate carbon dioxide pollution from existing coal-fired power plants. EPA's guidelines contain subcategories that would require coal-fired power plants that will operate longer to meet more stringent emission control requirements. Although we support EPA's concept, we urge the agency to consider revising its approach to include more stringent emission limits. Our comments below first cover EPA's proposed subcategory approach. We then turn to the agency's proposed best system of emission reduction and emission limitations for each subcategory.

A. Subcategory Approach

EPA proposes to limit CO_2 emissions from existing coal-fired power plants using a subcategory approach under which plants that operate longer have more stringent emission reduction requirements than those that intend to retire in the near future. EPA explains that, based on information provided by the utility

---

[206] EPA, *Integrated Proposal Modeling and Updated Baseline Analysis* (July 7, 2023), at 5.

[207] *See* Comments of Clean Air Task Force and Natural Resources Defense Council on Proposed Rule (Aug. 8, 2023) at 75-78.

industry regarding planned retirements for economic reasons or other factors, plants set to retire in the near future will not be able to amortize and recoup the costs of installing pollution controls such as CCS.[208] Specifically, EPA stated that "industry commenters to the pre-proposal docket noted that many sources have plans to permanently cease operations in the coming years, and that GHG control technologies might not be cost reasonable for those units operating on shorter timeframes."[209] That information in turn informed the agency's consideration of the cost factor in determining the best system of emission reduction. EPA found that over one-third of existing coal-fired generating capacity plans to cease operation by 2032, and approximately half of the capacity will cease operations by 2040.[210] EPA further found that many coal-fired generating units "are part of utilities with commitments to net zero power by certain dates, or are in States or localities with commitments to net zero power by certain dates."[211]

Based on this industry input, EPA has devised four subcategories: (1) long-term electricity generating units (those that intend to operate beyond January 1, 2040); (2) medium-term electricity generating units (those that operate after December 31, 2031 and will cease operations prior to January 1, 2040); (3) near-term electricity generating units (those that will retire prior to January 1, 2035 and adopt an annual capacity factor limit of 20 percent); and (4) imminent-term electricity generating units (those that will cease operation prior to January 1, 2032).[212] We generally support EPA's subcategory approach, although suggest some revisions that would result in greater emission reductions.

EPA has broad authority under section 111(d) to identify subcategories, including on grounds of cost.[213] Here, EPA reasons that in light of the announced plans of many coal-fired power plants to cease operations in the near future, "[s]ubcategorizing on the basis of operating horizon is . . . relevant for determining

---

[208] 88 Fed. Reg. at 33,345.

[209] *Id.* at 33,343.

[210] *Id.*

[211] *Id.*

[212] *Id.* at 33,334.

[213] *See* 42 U.S.C. § 7411(d); 40 § C.F.R. 60.22a(b)(5); *Northeast Maryland Waste Disposal v. EPA*, 358 F.3d 936, 947 (D.C. Cir. 2004) (noting, in upholding subcategorization of waste combustors by plant capacity, "the dictionary definition [of 'class'] — 'a group, set, or kind marked by common attributes' — could hardly be more flexible" (quoting Webster's 3d New Int'l Dict. 416 (1976))).

the cost reasonableness of control requirements."[214] This is because "[w]hether the costs of control are reasonable depends in part on the period of time over which the affected sources can amortize those costs."[215] In other words, for generating units with shorter operating horizons, "controls will [] be less cost-effective and therefore may not qualify as the [best system]."[216]

While acknowledging some overlap between (largely) basing subcategories on source operating horizons and the ability of states to consider remaining useful life in establishing emission standards for particular sources, EPA explains that the two roles are distinct: EPA's role is to determine a generally applicable best system of emission reduction for a source category and, as appropriate, for subcategories, based on different classes, types, or sizes of sources.[217] By contrast, a state's authority to invoke remaining useful life is premised on the state's ability "to take into account the characteristics of a particular source that may differ from the assumptions EPA made in determining the best system generally."[218] For example, a state with a coal-fired generating unit scheduled for retirement at the end of 2035 that also would have a difficult time securing natural gas at its location could make a credible argument for a less stringent emission standard than the corresponding emission limitation EPA has proposed based on 40 percent co-firing with natural gas. We concur that EPA has indeed left room for states to apply the remaining useful life factor in determining emission standards for particular electric generating units.

With respect to imminent-term subcategory (units that retire prior to January 1, 2032), EPA seeks comment on whether to instead merge these units into the near-term subcategory. As we understand this concept, units that would have otherwise retired by the end of 2031—but with no restrictions on capacity, just on increasing their emission rate—would be allowed to operate a bit longer (until the end of 2034) provided that they agree to an annual capacity factor limit of 20 percent.[219] Although we take no position on this alternative, we urge EPA to consider the relative public health impacts of the two approaches, especially given

[214] 88 Fed. Reg. at 33,345.

[215] *Id.*

[216] *Id.*

[217] *Id.*

[218] *Id.*

[219] *Id.* at 33,344.

EPA's finding that at least some of these units are located in underserved communities.[220]

B. Best System of Emission Reduction and Emission Limitation

1. Long-term electricity generating units

For long-term electricity generating units, EPA determined the best system of emission reduction to be carbon capture and sequestration and is proposing an emission limitation of 90 percent capture of CO_2, the equivalent of an 88.4 percent reduction in emission rate. EPA's determination is well supported. The record shows that the technology is adequately demonstrated, achieves substantial emission reductions, and is cost-effective.

<u>Adequately Demonstrated</u>

As discussed above, a technology is adequately demonstrated if it has been shown to work in practice at a representative plant in the source category or in a similar industry. CCS readily meets this test.

Eight years ago, when EPA determined that the best system of emission reduction for new coal-fired power plants was partial CCS, the agency found that each of the three main components of CCS—capture, transport, and sequestration—was adequately demonstrated.[221] When EPA proposed to weaken the 2015 rule by, among other things, reversing its finding that CCS was adequately demonstrated, many of our offices submitted comments in opposition.[222] At that time, we noted several reasons why EPA's original finding of adequate demonstration was well founded:

- EPA's determination was based on a large body of evidence, including the agency's finding that the Boundary Dam project in Saskatchewan was a "commercial-scale fully integrated post combustion CCS project at a coal-fired power plant," as well as evidence of numerous smaller scale projects at coal-fired plants that could be successfully scaled up.[223]

---

[220] *See id.* at 33,413; RIA ch. 6.

[221] *See* 80 Fed. Reg. 64,510, 64,548–73 (Oct. 23, 2015).

[222] A copy of those comments (2019 Multistate Comments) is attached hereto.

[223] 2019 Multistate Comments at 37–38 (citing 79 Fed. Reg. at 64,548–58).

- The evidence in the record for CCS being adequately demonstrated was stronger than for other technologies previously found to be the best system by EPA and upheld by the courts.[224]

- A majority of states had enacted laws or regulations to support and promote the use of CCS, further supporting a finding of adequate demonstration.[225]

During the Trump Administration, EPA decided against finalizing its proposed reversal of its finding that CCS has been adequately demonstrated as a pollution control at new coal-fired power plants. That finding—and EPA's performance standard for new coal-fired power plants based on partial CCS—has therefore been in place for eight years.[226]

EPA's determination in the Proposed Rule that CCS is the best system of emission reduction for existing coal-fired power plants therefore begins from a solid foundation. And as EPA discusses in the preamble to the Proposed Rule, the three main components of CCS—capture, transport, and sequestration—are adequately demonstrated for existing coal-fired units.

With respect to CO_2 capture, SaskPower's Boundary Dam Unit 3, the electric generating unit that EPA significantly relied on in finding in 2015 that this approach was adequately demonstrated for new coal-fired plants, was an *existing* unit that was retrofitted with carbon capture pollution controls. Consistent with its previous finding, EPA notes in the proposed rule that Boundary Dam Unit 3 has continued to achieve capture rates of 90 percent of the CO_2 in flue gas using solvent-based post-combustion control.[227] Carbon capture has also been used successfully at a smaller scale for multiple years at several other coal-fired plants, including AES Warrior Run in Maryland and Shady Point in Oklahoma. EPA also cites carbon capture in use at other industrial process facilities, including the Searles Valley Minerals soda ash plant in California and the Quest steam methane reformer facility in Alberta. In addition, EPA references DOE-funded projects at two coal-fired power plants (Petra Nova in Texas and Plant Barry in Alabama) that operated

[224] 2019 Multistate Comments at 39–40 (citing EPA standards upheld in *Sierra Club v. Costle*, *Lignite Energy Council v. EPA*, and *Essex Chem. Corp. v. Ruckelshaus* with less robust record evidence than for CCS).

[225] 2019 Multistate Comments at 49–51 and Appendix B (attached hereto).

[226] Although a group of states and industry challenged the 2015 NSPS, the litigation has been in abeyance since 2017. *North Dakota v. EPA* (D.C. Cir. No. 15-1381).

[227] 88 Fed. Reg. at 33,291, 33,346.

for several years and achieved 90 percent or better capture rates.[228] EPA also cites the successful carbon capture at natural gas combustion turbines, which as detailed above (*supra* section III.D.1.), use similar core technology as coal-fired generating units.[229] Finally, EPA projects that even without the proposed rule, 9 gigawatts of coal-fired steam generating units would apply CCS by 2030.[230]

Likewise, the transport of CO_2 is adequately demonstrated, as EPA found in 2015. CO_2 has been transported in the U.S. by pipeline for 60 years, and there are currently more than 5,000 miles of CO_2 pipeline in operation as of 2021.[231] In addition, EPA notes that there are several new major pipeline projects or expansions in progress, including two in the Midwest and Great Plains that would add another 3,300 miles of pipeline infrastructure in the next few years. Based on an analysis by the Department of Energy, 77 percent of existing coal-fired electric generating units that have planned operations during or after 2030 are within 50 miles of potential saline sequestration sites, and another 5 percent are within 62 miles (100 kilometers) of sequestration sites.[232]

Regarding sequestration, the evidence further supports EPA's finding in 2015 that sequestration is adequately demonstrated for coal-fired power plants. First, the effectiveness of the long-term trapping of CO_2 has been demonstrated in geologic formations such as the Jackson Dome in Mississippi, the Bravo Dome in New Mexico, and the McElmo Dome in Colorado, in which large volumes of CO_2 have been trapped for millions of years.[233] Second, EPA cites the Department of Energy's Regional Carbon Sequestration Partnerships, which have demonstrated geologic sequestration through a series of field research projects that increased in scale over time, injecting more than 11 million tons of CO_2 with no indications of negative impacts to human health or the environment. DOE's Carbon Storage Assurance Facility Enterprise (CarbonSAFE) is demonstrating how knowledge from the field research can be applied to commercial-scale storage. Third, there are numerous additional saline facilities under development across the U.S. As evidence, EPA is currently reviewing Underground Injection Control Class VI geologic sequestration

---

[228] *Id.* at 33,293.

[229] *Id.* at 33,292–93.

[230] *Id.* at 33,346.

[231] *Id.* at 33,293–94.

[232] *Id.* at 33,294.

[233] *Id.* at 33,295.

well permit applications for proposed sequestration sites in at least seven states. Fourth, geologic sequestration has been proven to be successful in projects internationally. For example, EPA notes that in Norway, facilities have conducted offshore sequestration under the Norwegian continental shelf for over 20 years.

EPA also found that nearly all existing coal-fired generating units have access to geologic sequestration sites. Specifically, of the coal-fired generating units with planned operation during or after 2030, 90 percent are located within 100 kilometers of any of the considered formations, including deep saline, unmineable coal seams, and oil and gas reservoirs.[234]

In addition, states have continued to enact laws and regulations premised on the assumption that CCS is an adequately demonstrated method of reducing carbon emissions at coal-fired power plants. These are in addition to the voluminous state laws and regulations detailed in our 2019 comments. For example:

- In 2020, Wyoming passed a law requiring that at least 20 percent of an electric utility's portfolio be made up of coal-fired power plants equipped with carbon capture and storage technology by 2030.[235]

- In 2021, Kansas enacted a law that provides that the State Corporation Commission shall establish requirements, procedures, and standards for the safe and secure injection of carbon dioxide and maintenance of underground storage of carbon dioxide.[236]

- In 2022, Indiana enacted a law (H.R. 1209) that creates permitting and regulatory processes for underground CO_2 storage, outlines CO_2 injection rights, and provides a process by which the state would assume the responsibility and associated liability for stored CO_2 following a CCS project's completion.[237]

- Also in 2022, Kentucky enacted legislation to promote CCS, and declared in its findings that the "development and deployment of carbon capture and storage technology in the Commonwealth will allow industries to utilize

[234] *Id.* at 33,347.

[235] Wyo. Stat. Ann. §§ 37-18-101 & 102 (2020).

[236] KS Stat § 55-1637 (2021).

[237] Ind. Code Ann. §§ 14-39-1-1 et seq. (2022).

diverse fuel sources, create jobs, contribute to state and local tax bases, and enable Kentucky industries to remain competitive in the global economy."[238]

Best System of Emission Reduction Determination

EPA has also reasonably explained its determination that CCS constitutes the best system of emission reduction for long-term coal-fired electric generating units. Below we provide comments on certain aspects of this determination:

Cost. In determining that long-term existing coal-fired power plants can cost-effectively use CCS, EPA examined the combined costs of capture, transport, and storage. Factoring in the tax credits available as a result of the Inflation Reduction Act, the agency determined that for units with 50 percent capacity factor and 10-year amortization period, the dollar per megawatt hour ($/MWh) costs of reduction are comparable to or less than the costs for controls in analogous rulemakings ($10.60–$29/MWh), such as the costs to purchase scrubbers to comply with the 2011 Cross-State Air Pollution Rule or to purchase SCR to comply with the 2023 Good Neighbor rule.[239] We agree that this is one appropriate metric that the agency can consider in evaluating the cost criterion, and therefore supports a finding of CCS as the best system here. EPA also evaluated units with 70 percent capacity factor—a scenario that the agency found reasonable given that increases in utilization are likely at units that apply CCS due to the incentives provided in the section 45Q tax credit—and found compliance costs to be relatively less.[240] The agency even found that there could be *negative* costs for units with a 70 percent capacity factor; these negative costs "indicate that the value of the 45Q tax credit more than offsets the costs to install and operate CCS."[241] EPA therefore has demonstrated that long-term existing coal-fired power plants can install CCS at reasonable cost.

Level of Pollution Reduction. Addressing one of its failures in the ACE rule (discussed in Point II, *supra*), EPA has appropriately evaluated the extent of the reduction in CO_2 emissions in making its best system determination. The agency notes that 90 percent capture will result in emission rates that are 88.4 percent lower on a pound per megawatt hour gross basis compared to units without

[238] Ky. Rev. Stat. 353.802 (2022).

[239] 88 Fed. Reg. at 33,301, 33,348.

[240] *Id.* at 33,348.

[241] *Id.*

capture.[242] By contrast, natural gas co-firing at 40 percent would only yield emission rate reductions of about 16 percent, "far fewer emission reductions [and] without improving the cost effectiveness of the control strategy."[243] And, as discussed above, in the context of explaining its reasons for repealing the ACE rule, EPA discusses how heat rate improvements—the ACE rule's best system—achieve little, if any, pollution reductions.[244] In sum, the level of pollution reduction factor weighs heavily in support of finding CCS to be the best system for existing coal-fired electric generating units.

Energy Requirements. EPA evaluated an emission limit based on CCS with 90 percent capture on grid reliability and determined that "there would be no unreasonable impacts on the reliability of electricity generation."[245] The agency concluded that the time available before the compliance deadline of January 1, 2030, provides for adequate resource planning, including accounting for the downtime necessary to install the CO_2 capture equipment at long-term coal-fired electric generating units.

In addition to EPA's careful evaluation, in our experience compliance with federal air pollution requirements does not cause problems with grid reliability. States work with the federal government to ensure that sufficient generation resources are available over the near and long term. In the scenario where unforeseen circumstances result in a generating unit scheduled for retirement being needed to temporarily address a reliability need, state and federal agencies along with grid operators work to make sure the lights stay on.[246] And both EPA and state

---

[242] *Id.* at 33,350.

[243] *Id.* at 33,351.

[244] *Id.* at 33,336–37.

[245] *Id.* at 33,349.

[246] 16 U.S.C. § 824a(c)(1)–(3) (authorizing the U.S. Department of Energy to declare an emergency due to shortage of electricity or electric generating facilities and to require generation of electricity to address the emergency); U.S. Department of Energy, Order No. 202-21-2 (Sept. 10, 2021) (order declaring an emergency pursuant to 16 U.S.C. § 824a(c) at the request of a grid operator and authorizing dispatch from certain generating units); https://www.energy.gov/sites/default/files/2021-09/EXEC-2021-005025%20-%20Order%20202-21-2%20-%20signed%209-10-21.pdf; PJM, What Happens When an Owner Wants to Close Its Power Plant? (describing grid operator's use of temporary "reliability must run" contracts to provide for temporary continued operation of plant planning to close if there is a reliability issue), https://insidelines.pjm.com/what-happens-when-an-owner-wants-to-close-its-power-plant/; M. McVety, "Indian River Power Plant

enforcement officials can properly exercise enforcement discretion to account for noncompliance in such situations.[247] Moreover, given the long lead times for compliance under the Proposed Rule, there is ample opportunity for grid operators and state and federal agencies to evaluate and take action to prevent any potential future reliability issues well in advance.

On the flip side of the coin, climate change is hampering our efforts to ensure grid reliability.[248] The grids in our states are increasingly being jeopardized by extreme weather events, which are expected to only increase in severity unless we take prompt action to limit greenhouse gas emissions.

Advancement of Technology. As an additional factor supporting CCS as the best system, EPA states that "designating CCS as the [best system of emission reduction] will provide for meaningful advancement of CCS technology."[249] It is well established that in establishing performance standards, EPA may incentivize the further development of pollution control technologies. For example, in the litigation over EPA's 1979 performance standards for new coal-fired power plants, the D.C.

---

shutdown delayed for 4 years. Why your electric bill will rise?," Delaware online (Aug. 3, 2022), https://www.delawareonline.com/story/news/local/2022/08/03/coal-powered-indian-river-power-plant-shutdown-delayed/65384383007/ (example of reliability-must-run situation).

[247] EPA, "EPA Exercises Enforcement Discretion for All Power Plants in Florida," (Sept. 11, 2017) (authorizing operation of power plants without meeting all pollution requirement to maintain supply of electricity); 16 U.S.C. § 824a(c)(1)–(3) (declaring that any noncompliance with federal, state or local environmental laws or regulations resulting from emergency orders is not a violation of such laws or regulations and is not subject to civil or criminal liability); Dept. of Energy, Order No. 202-21-1 at 1–3 (Feb. 14, 2021) (order declaring an emergency pursuant to 16 U.S.C. § 824a(c) and authorizing dispatch from certain generating units notwithstanding possible exceedance of air pollutant emission limits), https://www.energy.gov/sites/prod/files/2021/02/f82/DOE%20202%28c%29%20Emergency%20Order%20-%20ERCOT%2002.14.2021.pdf; Texas Comm'n on Envtl. Quality, Winter Storm Elliot (noting that agency approved grid operator requests for enforcement discretion to ensure grid reliability), https://www.tceq.texas.gov/response/winter-storms/winter-storm-elliott.

[248] *See, e.g.*, U.S. Global Change Research Program, *Climate Science Special Report: Fourth National Climate Assessment, Volume II*, at 179–183 (D.J. Wuebbles, et al., eds., 2017).

[249] 88 Fed. Reg. at 33,350; *see also id.* at 33,303 ("[A] determination that a component of the BSER for new base load stationary combustion turbines (and long term coal-fired steam generating units) is the use of CCS will also likely incentivize the deployment of alternative CO_2 capture techniques at scale.").

Circuit observed that section 111(a)(1)'s "mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance."[250] In upholding the performance standards for sulfur dioxide, the court rejected the argument that the statute's "adequately demonstrated" language precluded EPA from considering the objective of advancing pollution control technology. "Recognizing that the Clean Air Act is a technology-forcing statute," the D.C. Circuit cited EPA's "authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard."[251]

Given that the statute's definition of standard of performance in section 111(a)(1) likewise applies to section 111(d), the D.C. Circuit's reasoning that EPA may consider technological innovation logically extends to emission guidelines for existing sources. Similarly, the Third Circuit Court of Appeals recently held that the Act's Reasonably Available Control Technology (RACT) requirement under section 172(c)(1) of the Act, which applies to existing sources, "is a technology-forcing standard designed to induce improvements and reductions in pollution for existing sources."[252]

Finally, EPA's best system CCS determination is squarely within the four corners of *West Virginia v. EPA*. Carbon capture pollution controls are in the mode of traditional technologies such as scrubbers and selective catalytic reduction installed on the plant to capture pollutants on site. It therefore fits within the types of the previous section 111 rules the Supreme Court cited with approval, *i.e.*, those

---

[250] *Sierra Club v. Costle*, 657 F.2d at 346.

[251] *Id.* at 364. *see also Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d at 391 ("Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present."); *Wisconsin Elec. Power v. Reilly*, 893 F.2d 901, 909 (7th Cir. 1990) ("'Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources.'") (quoting S. Rep. No. 91-1196, 91st Cong., 2d Sess. 17 (1970)); *cf. National Petrochemical & Refiners Ass'n v. EPA*, 287 F.3d 1130, 1144 (D.C. Cir. 2002) (upholding EPA's adoption of a technology-forcing standard for diesel engines, reasoning that "[i]n the absence of theoretical objections to the technology, the agency need only identify the major steps necessary for development of the device, and give plausible reasons for its belief that the industry will be able to solve those problems in the time remaining.").

[252] *Sierra Club v. EPA*, 972 F.3d 290, 294 (3d Cir. 2020); *see also id.* at 295 ("RACT is not designed to rubber-stamp existing control methods. It is a technology-forcing mechanism.").

"based on measures that would reduce pollution by causing plants to operate more cleanly."[253] The Court also made clear that it is well within EPA's authority to establish a pollution reduction rule under section 111(d) that "caus[es] an incidental loss of coal market's share."[254] And the record here shows that the Proposed Rule's impacts on coal-fired generation would be relatively minor compared to those already anticipated as a result of the Inflation Reduction Act and market forces.[255]

Emission Limitation

EPA has also shown that the emission limitation for long-term coal-fired generating units is achievable. As discussed above, the Boundary Dam coal-fired power plant has demonstrated capture rates of 90 percent of the CO_2 in flue gas using solvent-based post-combustion capture retrofitted to existing coal-fired steam generating units.[256] A feasibility study for SaskPower's Shand Power Station, a coal-fired plant, indicated achievable capture rates of 97 percent, even at lower loads.[257] The Petra Nova (Texas) and Plant Barry (Alabama) coal-fired power plants also have demonstrated capture rates of 90 percent or better.[258] As further evidence, EPA cited natural gas combustion turbines that have either captured or have been designed to capture 90–97 percent of CO_2.[259]

2. Medium-term electricity generating units

The agency has determined that co-firing natural gas at the level of 40 percent of annual heat input is the best system of emission reduction for medium-term coal-fired electricity generating units, *i.e.,* those that intend to operate beyond January 1, 2035, and commit to retire before January 1, 2040.[260] The level of emission limitation using this approach is a 16 percent reduction in emission rate on a pound of CO_2 per megawatt hour gross basis. We concur with

---

[253] 142 S. Ct. at 2599; *see also id.* at 2611 (distinguishing the Clean Power Plan's generation-shifting approach from previous section 111 rules that "focus[ed] on improving the performance of individual sources").

[254] *Id.* at 2613 n.4.

[255] *See* Section I.G, *supra.*

[256] 88 Fed. Reg. at 33,346.

[257] *Id.* at 33,291.

[258] *Id.* at 33,293.

[259] *See id.*

[260] *Id.* at 33,351.

EPA's best system determination for medium-term units, which is well supported by the evidence in the record.

Relatedly, we urge EPA to reduce the size of this subcategory by changing the relevant end date for medium-term units (*i.e.*, beginning date for long-term units) from January 1, 2040, to January 1, 2038—a change that—in light of the substantially greater emission reductions that CCS can achieve compared to co-firing with natural gas—could result in significant additional carbon pollution reductions. Such a revision is also economically justified. EPA's cost analysis shows that using an 8-year amortization period (which would equate with a January 1, 2038, cutoff date for the medium-term subcategory) would still have dollar per megawatt hour costs within the $10.60–$29/MWh range of previous EPA rules the agency cites.[261] Moreover, the costs of compliance with prior EPA power plant rules is only one metric in adjudging cost reasonableness. Under D.C. Circuit caselaw, the best system of emission reduction need not be cost effective; it need only be not "exorbitantly costly" to industry.[262] In previous air pollution rules for the power sector, for example, EPA has considered other cost metrics, such as the cost of compliance as a percentage of the power sector's historical revenue, expenditures, and rate changes.[263] Moreover, EPA could cite the social costs of greenhouse gases as an additional basis for justifying more stringent requirements.[264] Thus, there are ample grounds to find an 8-year amortization period cost reasonable, justifying revising the end date for the medium-unit subcategory to January 1, 2038.

3. Near-term and imminent-term electric generating units

EPA has determined the best system for near-term and imminent-term electric generating units to be routine methods of maintenance and operation.[265] The emission limitation would be no increase in the emission rate (on a lb

---

[261] *See* 88 Fed. Reg. at 33,348 (estimating costs of $24/ton of CO_2 reduced and $21/MWh and noting that the cost of generation may be reasonable relative to the representative cost for a wet scrubber to control SO_2).

[262] *See Essex Chem. Corp.*, 486 F.2d at 433.

[263] *See* 81 Fed. Reg. 24,420 (Apr. 25, 2016) (supplemental cost finding for Mercury and Air Toxics Standards).

[264] *See* 88 Fed. Reg. at 33,412, 33,416 tbl. 10 (explaining that the climate benefits alone of the Proposed Rule are more than twice the compliance costs, and seven times more if human health benefits are added); RIA, ch. 7. In addition, as discussed in ***Appendix 3*** (attached hereto), EPA has omitted some key climate benefits; therefore the agency's analysis understates the benefits of reducing power plant carbon emissions.

[265] 88 Fed. Reg. at 33,356.

CO_2/MWh-gross basis) from baseline levels. EPA is taking comment on whether, alternatively, the best system for these units is low levels of natural gas co-firing. EPA found that "[f]or moderate increases in natural gas co-firing, units with existing gas ignitors may be able to increase the gas use at those ignitors at a capital cost of roughly less than $2/kW."[266] The agency further noted that units may be able to convert existing oil ignitors to gas ignitors for approximately the same cost. For both of these types of units, "[t]hese small modifications could likely achieve co-firing levels of up to 20 percent of heat input."[267] In light of EPA's finding that it would be very inexpensive for these units to be modified to be able to co-fire small amounts of natural gas and given EPA's determination in the context of medium-term units that co-firing with natural gas meets the other best system criteria, EPA should further consider this approach if it is likely to result in significant additional emission reductions compared to the current proposed approach.

V. ENVIRONMENTAL JUSTICE

A. EPA Must Conduct a More Comprehensive Cumulative Impact Analysis of its Final Rule.

We commend EPA for undertaking an Environmental Justice Impacts analysis for the Proposed Rule, but urge EPA to strengthen the Proposed Rule by expanding the scope of that analysis to more fully understand cumulative health and environmental impacts of the Proposed Rule on underserved communities.

1. EPA is required to conduct a comprehensive cumulative impact assessment including nonair quality health and environmental impacts of its Proposed Rule.

EPA is required to consider "any nonair quality health and environmental impacts" in determining the best system of emission reduction under section 111.[268] Indeed, even before that language was added to the statute, the D.C. Circuit recognized that "section 111. . . properly construed, requires the functional

---

[266] EPA, *Greenhouse Gas Mitigation Measures for Steam Generating Units: Technical Support Document* at 10 (May 23, 2023).

[267] *Id.*

[268] 42 U.S.C. § 7411(a)(1).

equivalent of a [National Environmental Policy Act (NEPA)] impact statement."[269] More specifically, EPA must "accompany a proposed standard with a statement of reasons that sets forth the environmental considerations, pro and con which have been taken into account."[270]

Thus, as is required under NEPA, in determining the best system of emission reduction, EPA must analyze the environmental, public health, and economic effects on underserved communities, including "public health data and industry data concerning the potential for multiple or cumulative exposure to human health or environmental hazards in the affected population and historical patterns of exposure to environmental hazards."[271] In this analysis, "the distribution as well as the magnitude of the disproportionate impacts in these communities should be a factor in determining the environmental preferable alternative."[272] Furthermore, "agencies should elicit the views of the affected populations on measures to mitigate a disproportionately high and adverse human health or environmental effect."[273] And, consistent with the section 111's language and D.C. Circuit precedent, CEQ's guidance provides that where an agency is implementing a statute that requires the "functional equivalent" of a NEPA analysis and the proposed action may disproportionately impact overburdened communities, the agency "should fully develop and consider alternatives to the proposed action whenever possible, as would be required by NEPA."[274]

As EPA recognizes, numerous executive orders also oblige EPA to conduct a comprehensive analysis of, and work to mitigate, the cumulative effects of its Proposed Rule.[275] For example, Executive Order 14096 expressly requires federal agencies to identify and address "disproportionate and adverse human health and

---

[269] *Portland Cement Ass'n*, 486 F.2d at 384; *Sierra Club v. Costle*, 657 F.2d at 331 (recognizing "Congress made no attempt to cut back on EPA's ability to apply the new terms broadly" with 1977 addition of requirement to consider "any nonair quality health and environmental impacts" in Section 111(a)(1)).

[270] *Portland Cement Ass'n,* 486 F.2d at 385; *see also Essex Chem. Corp.*, 486 F.2d at 431 (section 111 implicitly requires a NEPA-type analysis).

[271] Council on Environmental Quality (CEQ), Environmental Justice Guidance Under the National Environmental Policy Act at 9 (Dec. 10, 1997). CEQ has oversight of the federal government's compliance with E.O. 12898 and NEPA. *Id.* at 1.

[272] *Id.* at 15.

[273] *Id.* at 16.

[274] *Id.* at 17.

[275] RIA at 6-1.

environmental effects (including risks)" including the cumulative impacts and effects related to climate change.[276] Executive Order 14008 also directs federal agencies to "secure environmental justice and spur economic opportunity for disadvantaged communities that have been historically marginalized and overburdened by pollution and underinvestment" and "to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities."[277] And other Executive Orders similarly require assessment of cumulative impacts on underserved communities and communities experiencing environmental injustice, and affirmative work toward equity and environmental justice in agency actions.[278]

2. EPA should expand its Environmental Justice Impacts analysis to more fully assess the environmental justice and cumulative impacts of the Proposed Rule.

In chapter 6 of its Regulatory Impact Analysis, EPA conducted an assessment of Environmental Justice Impacts of the Proposed Rule that analyzes multiple important impacts on underserved communities. EPA's Environmental Justice Impacts analysis is an important first step in understanding potentially disparate impacts of the Proposed Rule. But it presently considers an unduly narrow range of impacts. Accordingly, to strengthen the Proposed Rule we urge

---

[276] 88 Fed. Reg. 25,251, 25,253 (Apr. 26, 2023).

[277] 86 Fed. Reg. 7619, 7629 (Feb. 1, 2021).

[278] *See, e.g.*, Exec. Order No. 13,985, 86 Fed. Reg. 7009 (Jan. 25, 2021) (directing all federal agencies to "work to redress inequities in their policies and programs that serve as barriers to equal opportunity"); Exec. Order No. 13,990, 86 Fed. Reg. 7037 (Jan. 25, 2021) (directing all executive departments and agencies to address any actions that conflict with goals of reducing greenhouse gas emissions and prioritizing environmental justice, among other national objectives); Exec. Order No. 13,563, 76 Fed. Reg. 3821 (Jan. 21, 2011) (directing that agencies select regulatory approaches that maximize net benefits including "distributive impacts[] and equity" and "[w]here appropriate and permitted by law, each agency may consider (and discuss qualitatively) values that are difficult or impossible to quantify, including equity . . . and distributive impacts."); Exec. Order No. 12,898, 59 Fed. Reg. 7629 (Feb. 16, 1994) (directing each federal agency to "make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations," including "multiple and cumulative exposures"); Exec. Order No. 12,866, 51 Fed. Reg. 51,735 (Oct. 4, 1993) (ordering agencies to consider "distributive impacts[] and equity" in designing regulations); *cf.* Exec. Order on Modernizing Regulatory Review (Apr. 6, 2023) (requiring Office of Management and Budget "to recognize distributive impacts and equity, to the extent permitted by law").

EPA to more comprehensively assess environmental justice and distributive impacts of the Proposed Rule.

EPA's current Environmental Justice Impacts analysis should be enhanced in several important respects. As an initial matter, it is unclear how EPA's updated modeling, released July 7, 2023, would alter EPA's Environmental Justice Impacts analysis. EPA should update its analysis to reflect the latest modeling.

Additionally, to comply with its statutory obligation to take into account "any nonair quality health and environmental impact" in identifying the best system of emission reduction, EPA must analyze the extent to which its chosen best system would extend the life of fossil-fueled units or require installation of infrastructure that poses additional risks to surrounding communities, as compared to the baseline and alternative best systems.[279] EPA acknowledges these concerns,[280] but does not fully analyze the actual impact of those realities. Instead, EPA indicates that such impacts *may* be assessed in future rulemakings or potential permitting processes.[281] If EPA expects its Proposed Rule to increase deployment of CCS and hydrogen technologies, however, EPA should incorporate information regarding resulting health and environmental impacts into its Environmental Justice Impacts analysis and work to reduce any identified disparities in adopting new source performance standards and require states to do the same in state plans governing existing sources.[282]

Additionally, EPA's proximity analysis only assesses impacts of existing coal units greater than 25 megawatts and does not assess proximity of underserved

[279] 42 U.S.C. § 7411(a)(1); CEQ Environmental Justice Guidance at 17 (agencies must "fully develop and consider alternatives to the proposed action whenever possible, as would be required by NEPA").

[280] *See, e.g.*, EPA, *Fact Sheet for Communities with Environmental Justice Concerns: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule* at 4 ("[o]ne concern is that adding CCS to EGUs can extend the life of an existing coal-fired steam generating unit, subjecting local residents who have already been negatively impacted by the operation of the coal-fired steam generating unit to additional harmful pollution. Communities have also expressed concerns about CO2 pipeline safety and geologic sequestration.").

[281] *See*, *e.g.*, *id.* at 5.

[282] *See Portland Cement*, 486 F.2d at 386 ("[t]o the extent that EPA is aware of significant adverse environmental consequences of its proposal, good faith requires appropriate reference in its reasons for the proposal and its underlying balancing analysis.").

populations to existing natural gas-fired units.[283] While the stack emissions impacts of gas-fired units may be more moderate, EPA should nonetheless evaluate the units' proximity to underserved populations. Indeed, such analysis is particularly important if EPA is, as it claims,[284] employing the proximity analysis as a proxy for disproportionate impacts like noise, odors, and traffic—impacts that may not be meaningfully different as between coal- and gas-fired units. Further, as EPA acknowledges,[285] its pollutant-specific analysis only involves potential impacts from longer-term $PM_{2.5}$ and ozone exposures and does not assess shorter-term exposures, which are known to be harmful particularly to those suffering from acute respiratory disease.[286] EPA should supplement its analysis with modeling of short-term exposures expected to recur as a result of the Proposed Rule.

Finally, EPA should expand the scope of its Environmental Justice Impacts analysis to include additional relevant indicators in both the proximity and pollutant-specific analyses, as well as conduct additional criteria pollutant modeling and risk characterization, to fully understand the disproportionate burdens impacted communities already face and the cumulative impact of the Proposed Rule in light of such burdens. And EPA should also require that states conduct similarly robust cumulative impact analyses for state plans covering existing sources. Several states have incorporated or proposed more comprehensive factors and assessment in cumulative impact analyses. For example, Massachusetts recently proposed regulations[287] pursuant to a 2021 statute requiring cumulative impact analysis for air permits for facilities located in or near an environmental justice population, as

[283] RIA at 6-6 to 6-7.

[284] RIA at 6-6.

[285] RIA at 6-12.

[286] *See* Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 88 Fed. Reg. 5558, 5586–89 (Jan. 27, 2023) (detailing evidence of causal relationship between short-term exposure to $PM_{2.5}$ and cardiovascular and respiratory effects); EPA, *Health Effects of Ozone in the General Population*, https://www.epa.gov/ozone-pollution-and-your-patients-health/health-effects-ozone-general-population (last updated Apr. 20, 2023); EPA, *Health Effects of Ozone in Patients with Asthma and Other Chronic Respiratory Disease*, https://www.epa.gov/ozone-pollution-and-your-patients-health/health-effects-ozone-patients-asthma-and-other-chronic (last updated July 11, 2023).

[287] *See* Proposed 310 C.M.R. § 7.02(14) (proposed Dec. 29, 2022), https://www.mass.gov/doc/310-cmr-70214-cumulative-impact-analysis-amendments/download.

defined by state law.[288] As proposed, the regulations would require air permit applicants to prepare a cumulative impact report assessing thirty indicators relating to air quality and climate, nearby regulated facilities, health, socioeconomic, and nearby sensitive receptors.[289] The regulations would also require cumulative impact analyses to include air quality dispersion modeling for all criteria pollutants as well as cancer and non-cancer risk characterization of air toxics or, alternatively, a refined risk characterization based on air dispersion modeling.[290]

New Jersey also recently adopted environmental justice regulations[291] pursuant to a 2020 statute requiring an assessment of existing environmental and public health stressors and the presence or absence of "adverse cumulative stressors" in an environmental justice impact statement (EJIS) for permits for facilities, including air permits for major sources of air pollution (i.e., gas-fired plants), located in or near a state designated overburdened community.[292] Where communities are already subject to adverse cumulative stressors or where a facility will create adverse cumulative stressors, the applicant must submit supplemental information including detailed information of the site conditions and pollution control measures.[293]

Similarly, Minnesota requires a Cumulative Levels and Effects Analysis as part of air permit applications for any facility in a geographically defined section of South Minneapolis.[294] This analysis includes evaluation of environmental health data, community stressors and vulnerabilities, contributions from nearby sources, and modeling results for air toxics and criteria pollutants. EPA should expand the

---

[288] 2021 Mass. Acts,, ch. 8, sec. 56, 102C, https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.

[289] *See* Proposed 310 C.M.R. § 7.02(14)(c) tbl. 1.

[290] *See id.* § 7.02(14)(d)–(e).

[291] *See* N.J. Admin. Code § 7:1C, https://dep.nj.gov/wp-content/uploads/rules/rules/njac7_1c.pdf.

[292] New Jersey Environmental Justice Law, N.J. Stat. § 13:1D-157 to § 13:1D-161, https://dep.nj.gov/wp-content/uploads/ej/docs/ej-law.pdf .

[293] *See* N.J. Admin. Code § 7:1C-3.2.

[294] *See* Minn. Stat. 116.07 subd. 4a; *see also* Air Permitting in South Minneapolis, https://www.pca.state.mn.us/business-with-us/air-permitting-in-south-minneapolis (last visited Aug. 3, 2023); C. Ellickson et al., *Cumulative Risk Assessment and Environmental Equity in Air Permitting: Interpretation, Methods, Community Participation and Implementation of a Unique Statute*, 8 Int. J. Env. Res. Public Health 4140 (Nov. 2011).

scope of its proximity and pollutant analyses to account for such indicators in assessing the cumulative impact of the Proposed Rule against burdens faced by impacted communities.

B. EPA Should Use Every Available Authority to Develop a Robust Regulatory Framework and Minimize Health and Safety Risks from its Final Rule.

As EPA acknowledges, CCS and co-firing with hydrogen, if insufficiently regulated, may carry additional potential health and safety risks to communities with environmental justice concerns.[295] But EPA and other federal agencies have ample authority to address these risks. Swiftly and diligently exercising these authorities would provide further support for EPA's proposed best system here and ensure that the Proposed Rule does not further burden underserved communities. Below, we identify several environmental justice concerns and offer recommendations for EPA's consideration for future action. In general, we encourage EPA to confront these health and safety concerns as soon as possible, promptly review and update existing regulatory frameworks, prioritize the health and safety of underserved communities, and proactively engage and collaborate with the relevant regulatory agencies.

1. Carbon Capture and Sequestration

Underserved communities have raised concerns about elevated safety risks at multiple points of the carbon management supply chain: from extending the life of fossil fuel emitting electric generating units to a possible surge in new infrastructure to capture and transport CO_2, and from pipeline leakage risks to the security of underground storage.[296] As such, we urge EPA to critically assess all its

---

[295] *See* 88 Fed. Reg. at 33,413–14 (recognizing and considering "the various concerns that potentially vulnerable communities have raised with regard to the use of CCS" and noting that "hydrogen production presents a unique set of potential issues for vulnerable communities").

[296] *Id.*; *see also* White House Environmental Justice Advisory Council, Justice40 Climate and Economic Justice Screening Tool & Executive Order 12898 Revisions Interim Final Recommendations at 57–58 (May 13, 2021), https://www.epa.gov/sites/default/files/2021-05/documents/whejac_interim_final_recommendations_0.pdf (including CCS among the "types of projects that will not benefit a community); Collective EJ Statement on Engineered Carbon Capture, Use, and Storage (CCUS) in California (June 2022), https://ww2.arb.ca.gov/sites/default/files/2022-

existing authority and to explore partnerships with other agencies to establish a more robust regulatory regime for CCS in future rules. EPA identifies several regulatory programs in response to stakeholder concerns surrounding CCS deployment.[297] We now address each of these in turn.

Non-CO_2 emissions: New Source Review Permitting

Major New Source Review (NSR) provides an opportunity for underserved communities to give input on permits for major modifications to existing electric generating units and new sources, and it allows EPA and state permitting authorities to require pollution control technologies to limit pollutant emissions.[298] In the Proposed Rule, EPA addresses underserved communities' concerns about CCS by noting that "a CCS retrofit may trigger" major NSR permitting.[299] But EPA also acknowledges that it does not expect most CCS installations to trigger major NSR requirements.[300] We encourage EPA to strictly enforce major NSR permitting whenever applicable, review its processes to find opportunities for meaningful engagement on CCS projects outside of the NSR process, and collaborate with relevant agencies to assess the effect of CCS deployment on air quality to inform future regulatory actions.[301]

08/Collective%20EJ%20Statement%20on%20Engineered%20Carbon%20Capture%2C%20Use%2C%20and%20Storage%20%28CCUS%29.pdf.

[297] *Id.* at 33,247–48.

[298] *See generally id.* at 33,350 ("the permitting authority may determine that the NSR permit requires the installation of SCR") and *id.* at 33,414 ("[i]f the source is undergoing major NSR permitting, the permitting authority would provide an opportunity for the public to comment on the draft permit").

[299] *Id.* at 33,413–14.

[300] *See id.* at 33,408 ("we expect this situation to not occur often").

[301] *See* CEQ Carbon Capture, Utilization, and Sequestration Guidance, 87 Fed. Reg. 8808, 8809 (Feb. 16, 2022) ("the successful widespread deployment of responsible CCUS will require strong and effective permitting...[and] meaningful public engagement early in the review and deployment process") and *id.* at 8,811 ("CEQ recommends that agencies, including EPA and DOE, collaborate on studies regarding the effect of carbon capture deployment on air quality in the United States").

CO$_2$ Storage: Underground Injection Control Regulations

EPA regulates CO$_2$ injected and stored underground, in what are known as Class VI wells, through its UIC Program.[302] Under the program, states may apply for primary enforcement and permitting responsibility ("primacy").[303] In light of recent concerns surrounding state UIC programs,[304] we urge EPA to review these applications carefully, with attention to impacts on underserved communities. For example, in assessing Class VI primacy applications, EPA should consider whether applicants have demonstrated successful facilitation of a Class II program[305] and compliance with a state's Title VI obligations.[306] And once Class VI approval is

---

[302] *See* 40 C.F.R. §§ 144–48; Federal Requirements Under the UIC Program for CO$_2$ Geologic Sequestration Wells, 75 Fed. Reg. 77,230 (Dec. 10, 2010) (adding Class VI wells to the UIC program).

[303] 40 C.F.R. § 145.

[304] *See e.g.*, Letter from Reps. Lloyd Doggett and Joaquin Castro to Administrator Regan (July 14, 2023), https://castro.house.gov/imo/media/doc/castro-doggett-epa-letter.pdf (discussing concerns with Texas administration of UIC program in context of Class VI application, including Railroad Commission of Texas's history of waiving its own rules to favor oil and gas interests over health and storage and insufficient attention and funding provided to plugging inactive wells—which threaten health of groundwater, soil, and air); Environmental Defense Fund, Comment Letter on Proposed Class VI Program Revision Application for State of Louisiana at 2–3 (July 3, 2023), https://www.regulations.gov/comment/EPA-HQ-OW-2023-0073-0179 (discussing concerns about Louisiana administration of UIC program in context of Class VI application, including lack of state regulatory administrative capacity, large quantity of orphaned wells, and underground sinkholes and blowouts related to underground injection activities under state's regulatory purview).

[305] Class II wells are also used to inject CO$_2$ underground, except for enhanced oil recovery rather than geological storage, and they are considered the closest analogue to the Class VI well program. 40 C.F.R. § 144.6; Earthjustice, Comment Letter on Proposed Class VI Program Revision Application for State of Louisiana at 2–3 (July 3, 2023), https://earthjustice.org/wp-content/uploads/2023/07/comments-on-epas-proposed-approval-of-la-class-vi-primacy-application_2023jul03.pdf; *see also* Congressional Research Service, *CO$_2$ Underground Injection Regulations: Selected Differences for Enhanced Oil Recovery and Geologic Sequestration* (June 16, 2020), https://crsreports.congress.gov/product/pdf/IF/IF11578#:~:text=Class%20II%20wells%20are%20used,to%20inject%20CO2%20for%20GS.

[306] Title VI of the Civil Rights Act of 1964 prohibits discrimination on the basis of race, color, and national origin in programs receiving federal financial assistance. 42 U.S.C. § 2000d. EPA's nondiscrimination regulations create an affirmative obligation for recipients of EPA financial assistance from taking actions that are "intentionally discriminatory as well as practices that have an unjustified discriminatory effect." EPA, *Legal Tools to Advance Environmental Justice: Cumulative Impacts Addendum* at 45 (Jan. 2023),

granted, EPA should vigilantly monitor state programs and promptly withdraw approval when a state program fails to comply with EPA requirements.[307] Lastly, EPA should review its Class VI UIC regulations—which have not been updated since 2011—and consider supplemental rulemakings to ensure the regulations reflect EPA's current views on safety and meaningful public engagement.[308] We urge EPA to prioritize federal regulation of Class VI wells and approve the delegation to states only when the state has demonstrated that it can safely and effectively regulate its wells.

CO_2 Transportation: Collaborating with PHMSA on Pipeline Safety Rulemaking

EPA should be fully aware of safety risks, potential impacts, and regulatory gaps associated with additional CO_2 pipeline infrastructure resulting from its final rule.[309] Incentivizing the buildout of CO_2 pipelines without necessary safety regulations in place could put frontline communities at risk, as exemplified by a 2020 pipeline rupture in Satartia, Mississippi, which forced 200 residents to evacuate and hospitalized 45.[310] The Pipeline and Hazardous Materials Safety Administration (PHMSA) currently regulates the safety of CO_2 pipelines; however,

---

https://www.epa.gov/system/files/documents/2022-12/bh508-Cumulative%20Impacts%20Addendum%20Final%202022-11-28.pdf; *see also* Earthjustice Comment Letter at 31–33.

[307] As authorized under 40 C.F.R. § 145.33, including for failure to comply with the terms of the Memorandum of Agreement between EPA and a state (§ 145.33(a)(4)). For example, EPA should strongly enforce the requirements of its Memorandum of Agreement with Louisiana regarding its Class VI primacy application. Memorandum of Agreement Addendum 3 Between Louisiana and EPA Region 6 for the Class VI UIC Program at 4–5 (Mar. 2023), https://www.regulations.gov/document/EPA-HQ-OW-2023-0073-0007/.

[308] EPA announced a plan to review its rulemaking on Class VI wells and determine if modifications were needed every six years when it initially expanded the UIC program in 2010; it has not updated its regulations since. 75 Fed. Reg. at 77,241.

[309] Even before the Proposed Rule, it was estimated that the United States will need to expand its CO_2 pipeline capacity 14x–19x by 2050. GAO-22-105274, *Decarbonization: Status, Challenges, and Policy Options for Carbon Capture, Utilization, and Storage* at 35–36, Figure 9 (Sept. 2022), https://www.gao.gov/assets/gao-22-105274.pdf.

[310] CO_2 is odorless and heavier than air in a supercritical state, meaning it can go undetected while displacing the oxygen around it when released, which can lead to asphyxia and even death at extreme concentrations. PHMSA, *Failure Investigation Report–Denbury Gulf Coast Pipelines LLC–Pipeline Rupture/Natural Force Damage* (May 26, 2022), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf; Minnesota Department of Health, Carbon Dioxide, https://rb.gy/xjr3h (last updated Oct. 3, 2022).

its regulations only cover CO_2 transported in a supercritical state above 90 percent concentration, leaving a regulatory gap for CO_2 transported in liquid or gaseous form.[311] And while the agency is in the process of proposing rules governing the shipment of CO_2 in non-supercritical states, it is not expected to release an updated proposed rule until 2024, nor has it announced a final rulemaking date.[312] Therefore, we encourage EPA to urge PHMSA to release interim guidance that they will regulate CO_2 transport in all forms, and to later collaborate with PHMSA on its official rulemaking efforts to strengthen CO_2 pipeline safety and leak detection regulations.[313]

2. Hydrogen Co-Firing

Hydrogen co-firing poses many of the same potential challenges as CCS for underserved communities, including extending the life of fossil fuel-emitting electric generating units and pipeline transportation safety concerns. Hydrogen also poses unique challenges such as an elevated risk of NOx emissions and upstream fuel production concerns. We encourage EPA to consider these issues when devising its final rule and to work with its partner agencies in future rulemaking efforts to create a safer and more robust regulatory framework for the hydrogen economy.

Non-CO_2 Emissions: New Source Review and NOx Emissions Concerns

Like CCS, EPA notes that for facilities that elect to co-fire with hydrogen, "there exists an opportunity for community engagement" as part of major NSR

---

[311] *See* Pipeline Safety Trust, Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations at 1–2 (Mar. 23, 2022), https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf; California Natural Resources Agency, SB 905 Proposal for Establishing a State Framework and Standards for Intrastate Pipelines Transporting Carbon Dioxide at 4 (Mar. 2023), https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Transitioning-to-Clean-Energy/SB-905--CO2-Pipeline-Regulatory-Framework--Stds-March-2023.pdf.

[312] *See* PIPES Act 2020 Web Chart, "OPS: Carbon Dioxide and Hazardous Liquid Pipelines" Rule (updated May 26, 2023), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-05/2023%20May%20PIPES%20Act%20Chart%20final.pdf (completing NPRM for Fed. Reg. publication by Jan. 26, 2024).

[313] PHMSA Deputy Administrator Tristan Brown has expressed interest in fostering greater collaboration with EPA. *See, e.g.*, Mike Soraghan, "Is Biden cracking down on pipeline violators?" E&E News (July 5, 2023), https://www.eenews.net/articles/is-biden-cracking-down-on-pipeline-violators/.

permitting, but again acknowledges that NSR may not often apply.[314] EPA also acknowledges that cofiring with hydrogen can increase emissions of NOx,[315] a harmful pollutant that is a precursor to ozone and the secondary formation of ambient $PM_{2.5}$.[316] To address these risks, EPA has highlighted turbine manufacturers and plant operators' efforts to produce low-NOx burners.[317] We urge EPA to take a stronger regulatory stance.[318] Specifically, we urge EPA to strictly enforce major NSR permitting whenever applicable and evaluate every possible avenue for limiting NOx emissions resulting from its final rule,[319] including partnering with other agencies where necessary.[320]

---

[314] 88 Fed. Reg. at 33,414 (noting that "[w]hile new combustion turbines that co-fire with hydrogen may trigger major NSR, there are cases in which they are less likely to trigger major NSR", but not estimating how frequently it expects this to occur). Elsewhere in discussing NSR permitting more generally, EPA says that while "it may be possible . . . to trigger major NSR . . . we expect this situation to not occur often." *Id.* at 33,408.

[315] *Id.* at 33,312; *see also* Hydrogen in Combustion Turbine EGUs – Technical Support Document at 3 (May 23, 2023), https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20Hydrogen%20in%20Combustion%20Turbine%20EGUs.pdf ("[h]igh hydrogen blends by volume also have the potential to increase nitrogen oxide (NOx) emissions from the combustion turbine as well as increase any upstream GHG emissions associated with the hydrogen production process").

[316] *See* 88 Fed. Reg. at 33,312 ("the combustion characteristics of hydrogen can lead to...increase[d] emissions of the criteria pollutant NOx"), 33,350 (NO_x is precursor to ozone), and at 33,412 (NOx is precursor to ambient $PM_{2.5}$).

[317] In most cases, EPA notes, the combustion turbines in new combined cycle units will be equipped with low-NOx burners to control flame temperatures and reduce NOx formation, *id.* at 33,302, and that "most turbine manufacturers are working to safely increase the levels of the hydrogen combustion in new and existing turbine models while limiting emissions of NOx. Hydrogen Technical Support Document at 5.

[318] EPA should endeavor to align with DOE's recommendation that "concerted efforts must be made to solicit and address community concerns around NOx emissions" to successfully unlock the potential of clean hydrogen as a national decarbonization pathway. Department of Energy, U.S. National Clean Hydrogen Strategy and Roadmap at 12 (June 2023), https://www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.

[319] Even when major NSR requirement do not apply, minor NOx sources can still be harmful to frontline communities.

[320] *See* 42 U.S.C. § 16161b(a)(2)(H); *see also* DOE Clean Hydrogen Roadmap at 3–4 (discussing amendment of § 814 of Title VIII of the Energy Policy Act of 2005).

Non-air Quality Impacts: Clean Hydrogen and Water Availability

Hydrogen produced by clean energy-powered electrolysis creates a low-greenhouse gas emission fuel, but it is also highly water-intensive.[321] Given the increasing regional strain on water resources from climate change, water access is likely to become an even greater environmental justice concern in the coming decades.[322] EPA acknowledges that "electrolyzer siting will need to take water availability into account."[323] We encourage EPA to fully assess water risks associated with the final rule and provide guidance to states and plant operators regarding the water resources needed to support electrolysis-produced hydrogen.[324]

Hydrogen Pipeline Transportation: Collaborating with PHMSA

Hydrogen has unique properties, like its small atomic size and corresponding tendency to leak, which raise distinct safety concerns from those involved in transporting natural gas by pipeline.[325] For example, a report by the California Public Utility Commission (CPUC) suggests that blending hydrogen into existing

[321] 88 Fed. Reg. at 33,304 (explanation of clean energy-powered electrolysis),33,414 (water scarcity impacts on vulnerable communities); *see also* DOE Clean Hydrogen Roadmap at 52 (similarly highlighting that "regional availability of water resources is also an important factor in the siting and sustainability of hydrogen production facilities").

[322] *See e.g*., Christopher Flavelle and Jack Healy, "Arizona Limits Construction Around Phoenix as Its Water Supply Dwindles", The New York Times (June 1, 2023), https://www.nytimes.com/2023/06/01/climate/arizona-phoenix-permits-housing-water.html; Dr. Mel Michelle Lewis, "Climate and Environmental Injustice: Thousands Without Water in Jackson, Mississippi", American Rivers (Sept. 2, 2022), https://www.americanrivers.org/2022/09/climate-and-environmental-injustice-thousands-without-water-in-jackson-mississippi/; UN Environment Programme, "As the climate dries the American west faces power and water shortages, experts warn" (Aug. 2, 2022), https://www.unep.org/news-and-stories/story/climate-dries-american-west-faces-power-and-water-shortages-experts-warn.

[323] 88 Fed. Reg. at 33,414.

[324] For example, EPA could engage the National Renewable Energy Laboratory (NREL) regarding the use of its high-resolution spatial analysis of U.S. water resources and scarcity by county. Elizabeth Connelly et. al., NREL Resource Assessment for Hydrogen Production at 39–40, Figure 21 (July 2020), https://www.nrel.gov/docs/fy20osti/77198.pdf.

[325] Pipeline Safety Trust, Accufacts Report: Safety of Hydrogen Transportation by Gas Pipelines at 4–6 (Nov, 28, 2022), https://pstrust.org/wp-content/uploads/2022/11/11-28-22-Final-Accufacts-Hydrogen-Pipeline-Report.pdf.

natural gas pipelines may be unsafe at concentrations greater than 20 percent;[326] anything greater may increase the risk of leakage, rupture, and potential ignition.[327] With hydrogen concentrations of 30–96 percent by 2038 required in the Proposed Rule,[328] new hydrogen-specific infrastructure will likely be needed, potentially negatively impacting underserved communities.[329] Additionally, while PHMSA's recently proposed Gas Pipeline Leak Detection and Repair Rule, if finalized, would apply to hydrogen pipelines,[330] it is not designed for the unique properties and challenges related to hydrogen transportation. Therefore, we encourage EPA to engage with PHMSA on developing guidance specific to hydrogen pipelines and assist wherever feasible in working toward a regulatory solution for safer hydrogen transportation.

C. EPA Should Define "Meaningful Engagement with Affected Stakeholders" Required in State Plans.

The Proposed Rule requires states to "undertake meaningful engagement with affected stakeholders," including communities that are most affected by and vulnerable to emissions from these power plants.[331] We support EPA's requirement that states consult affected stakeholders in their development of state plans for existing sources. As the Office of Information and Regulatory Affairs (OIRA) recognized in its recent guidance *Broadening Public Participation and Community*

---

[326] California Public Utility Commission, CPUC Issues Independent Study on Injecting Hydrogen Into Natural Gas Systems (July 21, 2022), https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-issues-independent-study-on-injecting-hydrogen-into-natural-gas-systems (Summary of Findings); *see also* CPUC, Final Report: Hydrogen Blending Impacts Study at 8, 17, Table 2 (July 18, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

[327] CPUC Final Report at 7. Hydrogen leakage could, if not abated, also undermine some of the rules' climate benefits. *See* Ilissa B. Ocko and Steven Hamburg, Environmental Defense Fund, Climate consequences of hydrogen emissions, 22 Atmos. Chem. Phys. 9,349 (2022), https://acp.copernicus.org/articles/22/9349/2022/acp-22-9349-2022.pdf.

[328] 88 Fed. Reg. at 33,244.

[329] *See* DOE Clean Hydrogen Roadmap at 43, Figure 23 (map of where hydrogen production and pipeline infrastructure is currently concentrated).

[330] Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. 31,890, 31,926, n.222 (May 18, 2023).

[331] 88 Fed. Reg. at 33,247; *see also* EPA, *Fact Sheet: Greenhouse Gas Standards and Guideline for Fossil Fuel-Fired Power Plants Proposed Rule* at 11, https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf.

Engagement in the Regulatory Process, "[b]roadening public participation and community engagement in the regulatory process can help agencies produce more responsive, effective, durable, and equitable regulations," particularly "when agencies engage communities through trust-based, long-term, and two-way relationships."[332] Meaningful involvement is thus critical to ensuring state efforts to implement the rule's emission limitations further—rather than frustrate—environmental justice principles.[333]

We thus recommend that the EPA provide further concrete guidance to ensure states fulfill the meaningful engagement requirement, specifically by including a definition and concrete examples of meaningful engagement in the final rule. EPA also should adopt a list of non-exhaustive minimum meaningful engagement requirements that must be demonstrated in state plans. And in doing so, we urge EPA to center community voices to ensure its definitions, guidance, and requirements reflect and are consistent with the recommendations of impacted communities.[334]

---

[332] Richard L. Revesz, Administrator, Office of Information and Reg. Affs., Memorandum for the Heads of Executive Departments and Agencies at 4 (July 19, 2023), https://www.whitehouse.gov/wp-content/uploads/2023/07/Broadening-Public-Participation-and-Community-Engagement-in-the-Regulatory-Process.pdf; *see also* Cary Coglianese et al., Transparency and Public Participation in the Federal Rulemaking Process: Recommendations for the New Administration, 77 Geo. Wash. L. Rev. 924, 946–47 (2009) ("Robust public participation in the rulemaking process allows agencies to obtain information that helps them (1) improve the quality of new regulations, (2) increase the probability of compliance, and (3) create a more complete record for judicial review. Public participation is also fundamentally linked to concepts of legitimacy and fairness in agency rulemaking."); Cynthia R. Farina et al., Knowledge in the People: Rethinking "Value" in Public Rulemaking Participation, 47 Wake Forest L. Rev. 1185, 1197 (2012) (positing that broader participation in rulemaking by "individuals and small private or public entities who would be directly affected . . .but who, based on historical participation patterns, are unlikely to engage in the conventional comment process" can contribute valuable information such as "information about impacts, ambiguities and gaps, enforceability, contributory causes, unintended consequences, etc. that is known by participants because of their lived experience in the complex reality into which the proposed regulation would be introduced.").

[333] Massachusetts law, for example, defines "environmental justice principles" to require "the meaningful involvement of all people with respect to the development, implementation and enforcement of environmental laws, regulations and policies, including climate change policies." Mass. Gen. Laws ch. 30, § 62.

[334] For example, the Massachusetts Attorney General's Office convened a Stakeholder Working Group to amplify community recommendations for incorporating

First, we urge EPA to strengthen its definition of meaningful engagement in several respects. EPA's December 2022 proposed Subpart Ba rule provided a definition of meaningful engagement that would apply to EPA's current proposed emissions guidelines.[335] Specifically, EPA would require "timely engagement with pertinent stakeholder representation in the plan development or plan revision process.[336] Such engagement must not be disproportionate in favor of certain stakeholders,[337] and must include the development of public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to participation to assure pertinent stakeholder representation, recognizing that diverse constituencies may be present within any particular stakeholder community.[338] It must include early outreach, sharing information, and soliciting input on the State plan."[339] In its discussion of meaningful engagement strategies in the December 2022 proposed Subpart Ba, EPA recognized the need to conduct outreach to communities that are already vulnerable to ambient air pollution and climate change-related impacts, communities in close proximity to affected facilities, and local Tribal communities.[340] One such strategy included a thorough notice requirement.[341]

While we commend EPA for recognizing these important components of meaningful participation, we urge EPA to adopt a revised, more robust and nuanced definition of meaningful engagement with specific examples of meaningful engagement practices. Existing definitions of "meaningful engagement" or "meaningful involvement" provide useful models for such requirements. For example, Massachusetts's Executive Office of Energy and Environmental Affairs defines "Meaningful Involvement" to require "that all neighborhoods have the right and opportunity to participate in energy, climate change, and environmental

---

meaningful participation into Massachusetts energy proceedings. *See* Overly Impacted & Rarely heard: Incorporating Community Voices into Massachusetts Energy Regulatory Processes (May 2023), https://www.mass.gov/doc/overly-impacted-and-rarely-heard-incorporating-community-voices-into-massachusetts-energy-regulatory-processes-swg-report/download.

[335] *See* 88 Fed. Reg. at 33,276 n.215.

[336] *Id.* at 33,398.

[337] *Id.*

[338] *Id.*

[339] *Id.*

[340] *Id.* at 33,398–99.

[341] *Id.*

decision-making including needs assessment, planning, implementation, compliance and enforcement, and evaluation, and neighborhoods are enabled and administratively assisted to participate fully through education and training, and are given transparency/accountability by government with regard to community input, and encouraged to develop environmental, energy, and climate change stewardship."[342] Similarly, the State of Oregon Environmental Justice Task Force recommends a "collaborative government approach" to engaging in capacity building for environmental justice communities to promote the core principle of "self-determination" and to further avoid the traditional "Decide. Announce. Defend." model of public participation.[343] Such definitions of "environmental justice" and "meaningful engagement" are also encoded in New York State law.[344] EPA should adopt a similarly robust definition required for state implementation here.

Next, to promote genuine and productive conversations between states and affected stakeholders, EPA also should adopt the following specific guidelines and requirements for meaningful engagement:

Identify All Relevant Stakeholders: EPA should require states to begin the process of meaningful engagement by gauging the interest of the local community members and affected stakeholders on issues of climate change, health, and

[342] Mass. Exec. Off. of Energy & Env't Affs., Environmental Justice Policy (updated June 24, 2021), https://www.mass.gov/doc/environmental-justice-policy6242021-update/download. OIRA, too, recently broadly defined "[p]ublic participation" as "any process that involves members of the public in government decision-making," which "seeks and facilitates the involvement of those affected by, or interested in, a government decision, including individuals; state, local, Tribal, and territorial governments; non-profit organizations; educational institutions; businesses; and other entities." Administrator Revesz Memorandum for the Heads of Departments and Agencies at 4. And OIRA defined "[c]ommunity engagement" as "a more specific concept within public participation that involves agency actions to build trust-based, long-term, and two-way relationships with communities, including underserved communities that have been historically left out of government decision-making." *Id.*

[343] State of Oregon Environmental Justice Task Force, Environmental Justice: Best Practices for Oregon's Natural Resource Agencies at 2–3, 10 (Jan. 2016), https://www.oregon.gov/dsl/About/Documents/Oregon_EJTF_Handbook_Final.pdf.

[344] N.Y. Env't Conserv. L § 48-0103 (2020), https://www.nysenate.gov/legislation/laws/ENV/48-0103#:~:text=Environmental%20Conservation%20(ENV)%20CHAPTER%2043-B%2C%20ARTICLE%2048%20%C2%A7,group%20established%20by%20section%2048-0105%20of%20this%20article.

equity.[345] In assessing potential interest, states should communicate with individuals; state, local, Tribal, and territorial governments; non-profit organizations; educational institutions; businesses; and other entities regarding their interest and activities related to climate change, health, and equity.[346] States should commit to working toward a better understanding of the perspectives of local communities and affected stakeholders, especially disadvantaged and underserved communities, on climate change health and equity, including the needs specific to their membership and availability of resources.[347]

Solicit and Respond to Feedback: EPA should require multiple methods for public notification, including publication in newspapers. distribution via email, flyer distribution, social media posts, TV/radio ads, and educational sessions. To increase opportunities for affected stakeholders to provide input, EPA should require states to accept written and oral modes of engagement, including the submission of pre-recorded videos. Additionally, stakeholders should be given the option to participate in events, either in-person or remotely, with the assurance that remote access will be available by phone or computer, so as not to require internet access. To further strengthen accessibility and transparency in the state planning process, we urge EPA to consider requiring states to provide opportunities to participate in stakeholder sessions outside the hours of 9:00AM and 5:00PM. Opportunities for meaningful engagement should not only solicit stakeholder feedback, but also provide information regarding the environmental and health risks related to state implementation to relevant stakeholders and community-based organizations. And to ensure accountability and transparency and to demonstrate appreciation for stakeholder feedback, we strongly recommend that states follow a community-led agenda and publish a full list of recommendations and comments received, along with detailed information about which recommendations will and will not be incorporated into the planning process and explanations for these decisions.

---

[345] Linda Rudolph et al., *Climate Change, Health, and Equity: A Guide for Local Health Departments* at 12 (2018) ("Conduct a scan to assess potential interest in the issue of climate change, health, and equity including both current and potentially new partners."), https://www.apha.org/-/media/files/pdf/topics/climate/climate_health_equity.ashx.

[346] *See id.* ("Conduct outreach to local Environmental Justice (EJ) groups, Community-based Organizations (CBOs), and community leaders to begin conversations regarding their interest and activities related to climate change, health, and equity.").

[347] Rudolph et al. at 12 ("Make an effort to meet potential CBO or community partners where they are and to develop an understanding of their current priorities, concerns and challenges, membership and constituency, strengths and resources, and level of interest in climate change and health equity.").

Require Concrete Accessibility Measures: We strongly urge EPA to adopt clear language accessibility requirements for all communications with affected stakeholders. EPA should require that states offer translation and interpretation services for Limited English Proficient (LEP) stakeholders, as well as for stakeholders who use American Sign Language (ASL). To effectuate a thorough language access policy, states should collaborate with community-based organizations and local community members to ensure that the needs of affected stakeholders are being considered in culturally sensitive and linguistically diverse modes of communication, *i.e.*, regular updates on websites, mailing lists, press releases, and social media posts.[348] Prior to hosting a community meeting or listening session, states should make educational materials available in multiple languages to affected stakeholders, explaining the states' role in the new regulations, how community members can participate, and relevant environmental and health impacts using plain language summaries and infographics.[349]

We urge the EPA to adopt the aforementioned recommendations regarding meaningful participation with affected stakeholders to ensure compliance with, and equitable implementation of, its final guidelines.

VI. PROPOSED STATE PLAN REQUIREMENTS

In this section, we provide our comments on the state plan provisions of the Proposed Rule, focusing on the aspects of emissions trading and averaging and application of the remaining useful life and other factors provision. Before addressing those specific aspects, however, we reiterate our request discussed in the preceding section (V.C, *supra*), that EPA require robust cumulative impact analyses for those state plans.

A. Emissions Trading and Averaging

The Attorneys General generally support the Proposed Rule's provision for states to incorporate averaging and market-based mechanisms, such as emission trading, into their section 111(d) state plans as compliance mechanisms. EPA's substantial experience and expertise with emission trading programs across various

---

[348] *Id.* ("Collaborate with CBOs and community members and leaders to develop culturally and linguistically appropriate materials for public information and dissemination and use an array of channels to ensure information reaches all members of the community.").

[349] Administrator Richard Revesz, Memorandum for the Heads of Departments and Agencies at 17–18.

pollutants well positions it to evaluate trading-based state plans to ensure they demonstrate equivalent or greater stringency with EPA's emission guidelines.

But the Attorneys General urge EPA to make clear that states may use an existing or future trading program developed independently of the rule in such state plans, so long as the trading program provides at least the aggregate level of emission control as EPA's emissions guidelines for affected sources (*i.e.*, those sources for which EPA's emission guidelines require 111(d) standards of performance), taking into account any standards imposed through application of remaining useful life and other factors. EPA should likewise commit to approving state plans incorporating trading programs (1) whether they cover a single state jurisdiction (intrastate programs) or multiple jurisdictions (interstate programs), and (2) whether they cover only affected sources or a broader category or categories of sources, so long as the state plan robustly demonstrates equivalent or greater stringency.

As EPA notes, trading programs have been used successfully on the federal, interstate, and state levels for decades to reduce air pollution.[350] EPA has developed substantial guidance in designing trading programs to ensure environmental integrity and efficient, healthy trading markets.[351] One of the reasons such programs are successful is that they allow "emission reductions at a lower cost relative to more prescriptive forms of regulation."[352] Another reason is that they "can allow the owners and operators of [power plants] to prioritize emission reduction actions where they are the quickest or cheapest . . . while still meeting electricity demand and broader environmental and economic performance goals."[353] And such programs generate "greater innovation and deployment of clean technologies that reduce emissions and control costs."[354]

---

[350] 88 Fed. Reg. at 33,393. We offer our support here for greenhouse gas trading programs, and note that we continue to have concerns about the use of trading to control mercury, toxics, and other pollutants with highly localized and severe health impacts.

[351] EPA, *Tools of the Trade: A Guide to Designing and Operating a Cap and Trade Program for Pollution Control* (June 2003), https://www.epa.gov/sites/default/files/2016-03/documents/tools.pdf; *see also* EPA, "Emissions Trading Resources," https://www.epa.gov/emissions-trading-resources (last visited July 24, 2023).

[352] 88 Fed. Reg. at 33,393.

[353] *Id.*

[354] *Id.*

EPA and state experience in implementing trading programs have identified several design elements that enhance these benefits. In general, a trading program that covers a greater share of significant emissions sources with a greater diversity in abatement costs may be more environmentally effective, promote a more efficient, stable, and liquid market for compliance instruments, and enable greater emission reductions at lower cost.[355] Simplicity in program administration and fungibility of compliance instruments are likewise important to a well-functioning, transparent, and robust trading program.[356] We therefore urge EPA to tailor its evaluation of trading-based plans to ensure programs with these characteristics are approvable when they otherwise demonstrate equivalent or greater stringency.

The Attorneys General agree with EPA's general criterion for approval of a state trading or averaging program, namely, that the program "maintains the level of emission performance for the source category that would be achieved if each affected EGU was individually achieving its presumptive standard of performance, after allowing for any application of [remaining useful life and other factors]."[357] In essence, this requires that the state program obtain the same or better emission reductions associated with the affected source categories as those required by the rule's presumptive standards of performance.

1. Inclusion of types of sources

EPA raises a number of questions concerning how to integrate certain subcategories of sources into a trading program. We believe that those questions can all be resolved reasonably. First, "EPA believes that it would not be appropriate to allow affected EGUs in certain subcategories—imminent-term and near-term coal-fired steam generating units and natural gas- and oil-fired steam generating units—to comply with their standards of performance through trading."[358] EPA also suggests that sources with standards of performance that apply the remaining useful life and other factors might similarly be excluded from a trading program, reasoning that these sources already benefit from operational flexibility because their presumptive standards are based on routine operations and maintenance.[359]

[355] *Id.*; EPA, *Tools of the Trade*, at 3–6.

[356] EPA, *Tools of the Trade*, at 3–6.

[357] 88 Fed. Reg. at 33,392; *see also id.* at 33,398.

[358] *Id.* at 33,393.

[359] *Id.* at 33,393–94.

No "undermining" of the intended stringency would result, however, provided that emissions among all affected sources meet the overall aggregate limit—which, here, would be set consistent with application of all applicable standards of performance, whether based on the remaining useful life or other factors or not.[360] Under EPA's general criterion for plan approval, such a trading program would be "satisfactory,"[361] and "reflect the degree of emission reduction achievable through application of the best system."[362] Because larger and more diverse trading markets can improve a program's liquidity, efficiency, and environmental efficacy, these sources' participation may enhance the program even if they are not required to reduce their emissions. For instance, a state could impose the relevant standard of performance for the identified sources—either no increase in emissions,[363] or a standard based on remaining useful life or other factors—as a unit-specific cap on emissions, but still allow the sources to trade or average any *overcompliance* beyond the applicable standard with other sources in other subcategories not subject to such a cap. If these sources can in fact reduce emissions beyond their standard, participation in a trading program would incentivize them to do so.

In addition, in the event that EPA chooses to establish or allow the alternative "above the baseline" emission standard for imminent-term coal-fired steam generating units,[364] permitting affected imminent-term sources to purchase compliance instruments to cover temporary, unforeseen increases in emissions may allow states to eliminate the compliance margin for these sources and revert to the "baseline" standard, promoting predictability and transparency. Similarly, the ability of sources to meet standards of performance through trading should inform how EPA evaluates an invocation of the remaining useful life and other factors, rather than exclude the source from the program altogether.[365]

---

[360] *Id.* at 33,394.

[361] *Id.* at 33,392.

[362] 42 U.S.C. § 7411(a)(1).

[363] 88 Fed. Reg. at 33,346, 33,357.

[364] *Id.* at 33,377.

[365] As EPA notes, "EPA has also proposed in subpart Ba that a State may not invoke [remaining useful life and other factors] to provide a less stringent standard of performance for a particular source if that source cannot apply the BSER but can reasonably implement a different system of emission reduction to achieve the degree of emission limitation required by the EPA's BSER determination." *Id.* at 33,383. Thus, a source that can comply within reasonable cost by purchasing compliance instruments instead of applying the best system of emission reduction may be ineligible for a less stringent standard of performance.

Second, we see no problem in allowing participation in a trading program by sources that receive Internal Revenue Code 45Q tax credit for capturing and sequestering CO_2.[366] The fact that such facilities have reduced costs because of the tax credit is a Congressional policy choice that is independent of any state plan under the rule. So any incentive for such facilities to maximize application of CCS generation and electric generation exists, whether the plan involves trading or unit-specific standards of performance. If, however, it is less expensive for the facility receiving the 45Q tax credit to reduce greenhouse gas pollution than for another facility not receiving that credit, that trading could be economically advantageous. In such a scenario, the revenue from the sale of compliance instruments could tip the scale in incentivizing sources on the margin to install CCS or help such sources secure financing to do so. As discussed above, these sources' participation in the trading program may carry broader benefits, such as strengthening the market. Most importantly, such trading would not interfere with achieving the rule's overall pollution reduction goals—the combination of all facility-specific emissions reduction mandates—which is the ultimate criterion for approving a trading-based plan.

EPA also suggests it would not be appropriate to include existing base load gas-fired plants, *i.e.*, combustion turbines of greater than 300-megawatt capacity, in a qualifying trading program because such facilities could move in and out of regulated status from year to year under the proposed rule, depending on whether their capacity factor exceeds 50 percent or not.[367] But nothing would bar a state from regulating those turbines beyond the requirements of the Proposed Rule, so that they would be required to participate in the trading program even when their capacity factor is less than 50 percent. For example, California's Cap-and-Trade Regulation covers all electric generating units that exceeded the minimum threshold (25,000 metric tons of CO_2e) in any year and does not release such a unit from coverage until after a full three-year compliance period of operating below that threshold.[368] Alternatively, if the compliance period for the trading program is annual, then it could be used as the annual compliance period for the standards of performance under the Proposed Rule. In that case, if a source operated at a capacity factor of less than 50 percent for a given compliance year, then then it would not need to participate in the trading program, and the aggregate amount of permissible emissions for the program under, say, a mass-based trading system,

---

[366] *See id.* at 33,394.

[367] *Id.*

[368] Cal. Code Regs., tit. 17, §§ 95802(a), 95812(c)(2)(A), 95835(c)(2)(A).

could be reduced by the emission level for that source under the presumptive standard. While states should certainly address the coverage issue that EPA identifies in a manner that preserves program integrity, there is no indication that states must exclude baseload gas-fired electric generating units from a trading program in order to achieve equivalent or greater stringency with the proposed emission guidelines.

EPA states that trading might not be effective because, given the subcategories created in the proposed rule and the expected decrease in the number of steam generating units subject to the proposed rule, there may be limited diversity among sources and thus limited opportunities for difference in control costs and performance.[369] We are less concerned with this potential market failure for several reasons. First, given the rationales noted above for including all affected sources in a trading program, the number of sources that can trade likely will be higher than EPA has stated. Second, an insufficient number of sources is even less likely if a state plan incorporates an interstate trading program rather than an intrastate program. Finally, if for a given state the number of covered sources is too small for a functioning intrastate trading program, and the state does not choose to link with or otherwise participate in a qualifying interstate trading program, then the state need not rely on—and EPA need not approve—an intrastate trading program in its state plan.

2. Rate-based trading

EPA articulates several advantages to rate-based trading over mass-based trading in ensuring the program's stringency.[370] However, there are notable disadvantages to rate-based trading —including the potential for an absolute increase in greenhouse gas emissions among sources. Rate-based trading limits participation in the market to power plants, inherently limiting the size of the trading market. Rate-based trading is also more difficult to harmonize with existing, effective greenhouse gas trading programs. Therefore, EPA should ensure that state plans with robustly designed mass-based trading programs are approvable as well.

We further note that, if a state plan were to incorporate a rate-based trading program, the types of sources discussed in the previous subsection can be included in such a trading regime. As EPA recognizes, a state plan could set emission rates

[369] 88 Fed. Reg. at 33,393.

[370] *Id.*

for each category or subcategory of sources, consistent with EPA's emission guidelines, and then allow trading of compliance instruments denominated in tons of CO_2.[371] Sources that would otherwise be subject to an emissions rate no greater than their historical rate, such as a near-term coal-fired steam generating unit, could purchase instruments to reach that rate and sell instruments resulting from any overcompliance. And if a 300-megawatt combustion turbine facility operating at 50 percent or greater capacity reduced its capacity factor to less than 50 percent, so that it was no longer a covered facility, the trading program could simply forego awarding instruments to that source or requiring their surrender.[372] While this suggests that emissions increases could occur—e.g., if a facility went from 51 percent capacity factor to a 48 percent capacity factor, it could theoretically increase its emission rate over its previously applicable standard of performance—this would not be a problem caused by trading, but instead a feature of how EPA has defined this particular subcategory.

3. Mass-based trading

The Attorneys General support inclusion of mass-based emission trading as a potential compliance mechanism in an approvable state plan, and in general support EPA's conception of such mass-based trading.[373] Mass-based trading facilitates a trading program's broader coverage beyond the affected sources, which can enhance market liquidity and efficiency, and promotes compatibility with existing programs. Mass-based allowances are a transparent metric that promotes easy comparison of different jurisdictions' targets and programs, in turn promoting multistate linkages. As with rate-based trading, we believe that the types of sources discussed in the subsection (1) above can be included in a mass-based trading regime.

We particularly appreciate EPA's concern that, under a mass-based trading program, certain changes in sources' operations could render emission budgets less stringent than intended.[374] For example, if a program calculated an emissions budget for coal-fired steam generating units with a medium-term operating horizon by aggregating these sources' historical emissions and then applying a 16 percent

[371] *Id.* at 33,394.

[372] *See id.*

[373] *Id.* at 33,394–95.

[374] *Id.* at 33,395.

reduction,[375] but failed to account for retirements or idling of covered units in the compliance period, the resulting surplus of compliance instruments could dilute the effective stringency of the program, so that the program no longer demonstrates equivalent stringency or "reflect[s] the degree of emission reduction achievable through application of the [best system]."[376]

Accordingly, we support requiring state plans that incorporate mass-based trading programs to include methods for accurately projecting or updating emission budgets, or otherwise addressing the potential for surplus emissions budgets. EPA identifies dynamic budgeting as a promising means to ensure appropriately stringent emission budgets over time.[377] We note, however, that in some cases, resetting intrastate or interstate emission budgets may occur through a political process, that is, by legislative amendment of statutes, and, even when done by administrative act, may involve substantial notice-and-comment procedures and environmental review. Thus, dynamic budgeting likely is workable only for those states whose state administrative law allow for ministerial action to update budgets. EPA should allow for such variation in approval process in reviewing and approving state plans that incorporate mass-based trading. Dynamic budgeting should be one means of demonstrating equivalent or greater stringency in a state plan incorporating mass-based trading, but not the exclusive means. Other means might include rigorous modeling of future power sector emissions under the state plan, substantiated by verified historical data, or economy-wide trading programs that are demonstrably stringent enough to absorb the surpluses and volatility caused by source retirements or reduced utilization. How a state plan may demonstrate equivalent stringency in such a case should be left in the first instance to the state, subject to EPA's review and notice-and-comment processes.

4. General program trading implementation elements

EPA proposes to require state plans to describe certain implementation elements of any trading programs they incorporate, including "compliance timeframes and the mechanics for demonstrating compliance under the program . . . [;] requirements for continuous monitoring and reporting of CO_2 emissions and generation; and . . . a tracking system for tradable compliance instruments."[378] We

[375] *See id.* at 33,245.

[376] 42 U.S.C. § 7411(a)(1).

[377] 88 Fed. Reg. at 33,395.

[378] *Id.*

agree that these requirements are necessary for EPA to evaluate whether a trading-based state plan satisfactorily demonstrates equivalent or greater stringency. EPA should further require trading-based state plans to describe: (1) coverage, *i.e.*, which sources and/or source categories beyond affected sources (if any) will participate in the trading program; (2) pollutants, *i.e.*, whether greenhouse gas emissions other than CO_2 are subject to mandatory monitoring, reporting, and compliance obligations; (3) linkages with other jurisdictions; and (4) market integrity provisions, *e.g.*, anti-fraud, anti-manipulation, and enforcement programs. These facets of a trading program also inform whether the program is likely to achieve in fact the emission reductions it promises.

EPA asks how a state program could address differential standards for different subcategories of sources, and in particular, the fact that different subcategories face different effective dates for regulation.[379] One way to address this would be to have a multistage or multiphase trading program. For a rate-based program, rates could be set for, and trading allowed among, the universe of sources regulated at any given time. Then, if a set of additional facilities becomes subject to the rule in, say, 2032, then the state agency could add those facilities to the trading system at that time and assign them rates, and if necessary or appropriate reassign rates to facilities previously subject to the trading system.

Somewhat similarly, for a mass-based trading program, when the initial subcategories of sources became subject to the rule, the state agency could set an emissions budget for those sources, and when at later dates new subcategories of source became subject to the rule, the state agency could set a new budget or budgets to reflect the additional subcategories. In neither case, however, would the state need to restrict trading between subcategories.

As EPA notes, trading programs provide great flexibility. For example, in a rate-based system, the state agency can set different emission rate standards for different subcategories of sources, and in a mass-based system, the state agency can set different trading rates for different subcategories of sources.

5. Banking of emission allowances

The Attorneys General support banking of compliance instruments, with certain conditions.[380] As EPA notes, banking may result in stockpiles of compliance

---

[379] *Id.*

[380] *Id.* at 33,396.

instruments that, when eventually used, could undermine a trading program's achievement of the required level of emission performance under the rule.[381] Accordingly, state plans that include trading programs with bankable instruments should describe how the program meaningfully limits holding and banking (such as time limits or quantity limits). In addition, the possible effects of banking should be included in the broader evaluation of possible impacts of a trading program, including any impacts on underserved communities.

6. Economy-wide and cross-sectoral trading

EPA should approve state plans that incorporate trading programs that cover entities beyond EPA's proposed affected sources, including economy-wide trading programs, as long as these plans demonstrate equivalent or greater stringency with respect to sources covered by the Proposed Rule. All existing greenhouse gas trading programs' coverages extend beyond EPA's Proposed Rule: for example, RGGI covers more existing gas-fired electric generating units than the Proposed Rule, while California's and Washington's cap-and-trade programs cover non-electric generating entities that emit significant amounts of greenhouse gases. Even states without existing trading programs may wish to create trading programs that cover entities beyond the proposed affected sources, in order to ensure a liquid, efficient, and stable trading market and a greater diversity in control costs and opportunities among covered entities that incentivizes cost-effective reductions. Because greenhouse gas pollution generally is well mixed in the atmosphere, there is sound basis for EPA, in the right circumstances, to find that greenhouse gas trading programs with broader coverage than the proposed affected sources are part of a "satisfactory" state plan.

EPA should evaluate these broader trading programs similar to how it evaluates "better-than-BART" trading programs under the Regional Haze Rule.[382] Under the regional haze program, a state can forego installing the "best available retrofit technology" on individual electric generating units if it establishes, by the clear weight of the evidence, that an alternative measure (like a trading program) will achieve greater reasonable progress than source-by-source BART installation.[383] This analysis involves establishing a benchmark emission reduction

---

[381] *Id.*

[382] *See Center for Energy & Econ. Devlt. v. EPA*, 398 F.3d 653, 660 (D.C. Cir. 2004) (finding EPA's "better-than-BART" approach allowed under Clean Air Act section 169B).

[383] 40 C.F.R. § 51.308(e)(2)(i), (i)(E).

that BART installation would achieve in BART-eligible sources, then showing that the state's alternative measure achieves better progress than this benchmark.[384]

Analogously, EPA could find a state trading program to be "better than [best system of emission of reduction]" if there is an overall reduction in greenhouse gas emissions in the power sector that is equivalent to or more stringent than the guidelines' reductions in affected sources only.

7. Interstate emissions trading

As noted above, we support the approvability of state plans that incorporate interstate emission trading regimes as a compliance mechanism. Interstate trading presents many of the same market advantages as an economy-wide program, including liquidity and diversity of sources, but likewise requires an additional showing to establish equivalent or greater stringency with EPA's emission guidelines. Generally, interstate trading programs like RGGI can readily identify a participating state's share of the regional budget. Comparison of a state's share of the regional budget, on the one hand, to the emissions budget representing application of the emission guidelines to affected sources within that state, on the other hand, should allow for such an equivalency demonstration.

While RGGI was developed as a single multistate program that each participating state enacted into local law, some interstate markets may emerge when different intrastate programs, developed independently with distinct objectives and design elements, decide to link markets, with each jurisdiction agreeing to count the other's instruments toward its local entities' compliance obligations.[385] In such a case, EPA may wish to require additional information about the linked jurisdiction's program to ensure that compliance instruments are equivalent across jurisdictions, with equally stringent provisions on verification, monitoring, and surrender, among other elements.

8. Rate-based averaging

The Attorneys General do not oppose a rate-based averaging program along the lines that EPA describes, with either facility-level averaging or owner/operator

---

[384] *Id.* § 51.308(e)(2)(i)(A)–(E); *Utility Air Reg. Group v. EPA*, 471 F.3d 1333, 1340–41 (D.C. Cir. 2006) (approving EPA methodology of establishing greater reasonable progress).

[385] *United States v. California*, 444 F. Supp. 3d 1181, 1186–87 (E.D. Cal. 2020) (describing California cap-and-trade program's framework for linkage with other jurisdictions' programs).

level averaging,[386] subject to an evaluation of the impacts of the averaging program on underserved communities similar to the evaluation of impacts from a trading program on such communities as discussed above. In addition, the state plan should demonstrate that such averaging does not lead to an absolute increase in emissions.

9. Relation to existing state programs

The Attorneys General appreciate EPA's recognition of the importance of existing state greenhouse gas trading programs, their significant impact in reducing carbon pollution from power plants, and their potential to reduce future greenhouse gas emissions beyond the power sector.[387] Principles of cooperative federalism and pragmatism favor allowing these states to use their existing trading programs to comply with the Proposed Rule, so long as they can demonstrate equivalent or better stringency than EPA's emission guidelines for affected sources. These programs represent years of consensus-building and technical development, and EPA should avoid disrupting these positive state efforts to the extent federal statutory prerogatives are satisfied. Leveraging existing state programs carries the further benefit of avoiding duplicative state and federal regulation, whether through simultaneous requirements under a state trading program and the federal standards of performance, or through regulation under competing trading programs, one under state law authority and one as part of a section 111(d) plan.

EPA's rate-based, source-specific emission guidelines, as well as certain views on trading expressed in the proposal (including its preference for rate-based trading and its suggested exclusion of various types of sources from trading programs), do "differ[ ] significantly" from existing state policies and programs.[388] EPA therefore seeks comment on whether any elements of proposed guidelines would interfere with implementation of existing state greenhouse gas trading programs.[389] Despite these differences, the rule should not interfere with any existing state trading programs as long as EPA adheres to its criterion for approvability—that is, as long as EPA commits to approving state plans that "maintain[ ] the level of emission performance for the source category that would be achieved if each affected EGU was individually achieving its presumptive standard of performance, after allowing

[386] *Id.* at 33,396.

[387] *Id.*

[388] *Id.*

[389] *Id.*

for any application of [remaining useful life and other factors]."[390] By definition, such trading programs would provide the same level of greenhouse gas control as EPA's presumptive standards of performance, despite any divergence in design elements or policy choices.

Certain design elements and choices will go toward a state plan's stringency, of course, and EPA should disapprove state plans based on trading programs that lack sufficient assurances of stringency. As in state plan development generally, demonstrating a trading program's equivalent stringency is necessarily a prospective exercise that involves projections and assumptions about how sources and state-covered entities will behave in future years. EPA's expertise and the public notice-and-comment process can ensure state plans are using reasonable assumptions and sound methods to project how their trading programs will likely compare to EPA's guidelines. EPA should evaluate trading programs in state plans for design flaws that undermine the program's apparent stringency, such as double-counting emissions, weak enforcement and monitoring provisions, or use of unverified data in the plan's projections. Nevertheless, EPA's ultimate criterion should be equivalent stringency, and any robust demonstration of equivalent stringency—addressing the above challenges in any reasonable way—should result in program approval.

B. Remaining Useful Life and Other Factors

Section 111(d) allows states, when establishing standards of performance for existing facilities, to take into account the remaining useful life of a specific source as well as other factors.[391] In December 2022, EPA set out proposed threshold requirements and other considerations and criteria for applying these factors to guide states that decide to take into account remaining useful life and other factors.[392] Many of our group of Attorneys General submitted comments in support of the December 2022 proposed rule.[393] EPA has not finalized that proposed rule as of the date of these comments.

---

[390] *Id.* at 33,392.

[391] 42 U.S.C. § 7411(d)(1).

[392] 87 Fed. Reg. 79,176 (Dec. 23, 2022).

[393] *See* Comments of the Attorney General of New York, *et al.*, on Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d); 87 Fed. Reg. 79,176 (July 6, 2023) (EPA-HQ-OAR-2021-0527-0092).

In the Proposed Rule, EPA is not seeking further comment on the December 2022 proposal, but is instead indicating how the remaining useful life considerations and criteria identified in the December 2022 proposal would be implemented in the context of these greenhouse gas emissions guidelines for power plants.[394] In particular, the Proposed Rule addresses these five issues: (1) how the threshold remaining useful life requirements would apply to sources under this rule; (2) how states would determine a source-specific best system of emission reduction and standard of performance applying remaining useful life factors; (3) how to apply to power plants the proposed remaining useful life requirement to consider the potential pollution impacts and benefits of control to the communities most affected by and vulnerable to emissions from the source; (4) proposed provisions for EPA review of state plans incorporating remaining useful life standards of performance; and (5) EPA's interpretation of the Clean Air Act that allows states to adopt and enforce standards of performance more stringent than the guidelines set out by EPA.[395]

The key issue here is that, in situations where EPA's presumptive standard of performance is, for an acceptable reason, not available for a particular source, state plans applying remaining useful life and other factors should still impose the most stringent standard of performance feasible under the circumstances. In that light, we address each of the five issues identified above.

1. Application of remaining useful life threshold requirements

The December 2022 proposed rule provided that states could deviate from the presumptive emission guidelines for a specific source set by EPA under section 111(d) if one of these threshold remaining useful life or other factors requirements were met: (1) unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility or technical infeasibility of installing necessary control equipment; or (3) other circumstances specific to the facility that are fundamentally different from the information considered in the determination of the best system of emission reduction.[396] EPA developed these three requirements to ensure consistency in the states' application of remaining useful life and other

[394] 88 Fed. Reg. at 33,381.

[395] *Id.*

[396] *Id.* at 33,382.

factors and so that remaining useful life would not be used to inappropriately undermine the stringency of the presumptive standards.[397]

The comments many of us submitted on the December 2022 proposed rule supported these proposed provisions, and we support the ways in which EPA proposes to apply them to developing standards for power plants under this specific Proposed Rule. We support EPA's proposed requirement that a state could only invoke remaining useful life to establish a less stringent standard for an electric generating unit if it demonstrated that there are "fundamental differences" between the source and EPA's best system determination, based on consideration of the factors that EPA considered in determining its best system.[398] Minor, nonfundamental differences would not be sufficient. The "fundamentally different" language also adds clarification on applying the "other factors" criteria, is consistent with variance provisions in the Clean Water Act and other environmental laws, and would prevent widespread application of these factors, which could complicate implementation, result in foregone emission reductions, and undermine the level of stringency in the emissions guideline.

EPA explains that in developing the best system of emission reduction for each of the subcategories in the Proposed Rule, it applied the statutory factors such as technical feasibility and costs, and those are the appropriate factors for states to apply when developing source-specific best systems under the remaining useful life provision. Thus, EPA properly explains that a state seeking to invoke remaining useful life would need to evaluate costs using the same metrics as EPA—\$/ton of CO_2 removed and \$/MWh electricity generated—and then determine that the costs for the source at issue were "significantly higher" than those that would be reasonable for that source, for example, costs at the 95th percentile of fleetwide costs.[399]

The Attorneys General also support provisions clarifying the use of the remaining useful life and other factors in the Proposed Rule. First, EPA indicates that a state may not impose a less stringent standard of performance based on remaining useful life if the source cannot apply the best system of emission reduction but can reasonably implement a different emission reduction system that

---

[397] *Id.*

[398] *Id.*

[399] *Id.* at 33,382–83.

can achieve the same degree of emission control.[400] Second, EPA explains that, in light of the fact that its standards for subcategories of coal-fired generation sources already take into account costs amortized consistent with the relevant operating horizons, it is unlikely that an electric generating unit could properly be given a less stringent standard based solely on the unit's remaining useful life. Third, the Attorneys General agree that, while a state may use remaining useful life to extend a source's deadline to comply with one of the presumptive standards of performance, such use should be "rare," as EPA's proposed emission guidelines already provide "relatively long lead times and compliance timeframes."[401]

2. Determination of source-specific best system of emission reduction and standard of performance

In the December 2022 proposed rule, EPA proposed to clarify how a state could determine a source-specific best system of emission reduction for a source that qualifies for an alternative best system based on remaining useful life or other factors. Specifically, a state plan submission must identify all emission reduction systems available for the source and then evaluate each system using the same factors and evaluation metrics EPA used to determine the best system for the source's subcategory.[402]

In the Proposed Rule, EPA applied these requirements in the context of setting a best system or standard of performance for power plants that qualify for remaining useful life or other factors, or explains why, in certain circumstances, it is not imposing those requirements in that context. EPA's proposed decisions on these points work toward ensuring that the most stringent degree of pollution control is set given relevant considerations when the presumptive degree cannot be met for an acceptable reason.

In general, EPA is prescribing that states evaluate certain specific controls when applying remaining useful life and setting a source-specific best system and standard of performance for power plants. For existing coal-fired plants in the long-term subcategory, EPA would require a state to evaluate natural gas co-firing as a potential source-specific best system, and if the source can implement CCS but not attain the standard of performance set by EPA, the state must evaluate a source-specific standard of performance. And for coal-fired plants in both the long-term and

[400] *Id.* at 33,383.

[401] *Id.* at 33,384.

[402] *Id.*

medium-term categories, states must evaluate lower levels of natural gas co-firing if the EPA presumptive emission level cannot be met.

Similarly, for existing combustion turbines, if a source cannot participate in the CCS subcategory, the state must demonstrate that the source cannot participate in the hydrogen co-firing subcategory, and vice-versa.[403] And if the source cannot meet the presumptive standards of performance for either category, the state must evaluate less stringent standards for either CCS or hydrogen co-firing.

In these circumstances, imposing consideration of certain controls is important to ensure that all relevant controls are considered and the emission standard established based on the most stringent control is selected. In this regard, for both the coal-fired and combustion turbine provisions discussed in the previous two paragraphs, EPA asks whether the proposed requirement to consider the identified technologies should be weakened to make consideration of the technologies a presumptively approvable approach.[404] We believe it more appropriate to leave consideration of the technologies as requirements, to ensure selection of the most protective control reasonably available.

The December 2022 proposed rule required that EPA, for purposes of evaluating remaining life, would (a) identify outermost dates to cease operation for a source category to qualify for consideration of remaining useful life or (b) provide a methodology and consideration for states to establish such a date.[405] EPA proposes to supersede that requirement for the various subcategories in the Proposed Rule.[406] We generally agree with EPA's reasoning on this point. In addition, we agree with EPA's particular point that, given that the subcategories for existing coal-fired sources are based on self-identified expected source lifetimes, there is little likelihood that a state would find reason to invoke the remaining useful life criterion for those sources.

As in the previous subsection, we support the qualifications that EPA proposes to impose on a source-specific best system and standards of performance for electric generating units on remaining useful life grounds. For example, if a source cannot reasonably apply the EPA best system but can use other emission reduction systems to achieve the same standard of performance as EPA's best

[403] *Id.* at 33,385.

[404] *Id.* at 33,384–85.

[405] *Id.* at 33,385.

[406] *Id.*

system, then the state should not be permitted to give that source a less stringent standard of performance. Next, if a state plan subjects a source to a less stringent standard of performance based on its remaining useful life, the plan should be required to identify the date by which the source commits to permanently cease operations as an enforceable requirement.[407] Similarly, if a state plan subjects a source to a less stringent standard based on a source's restricted capacity or other operating condition, the plan should be required to include that operating condition as an enforceable requirement.[408] In the absence of such enforceable requirements, a subsequent change in a facility's operations could result in foregone emission reductions and undermine the level of stringency in the emissions guideline.

3. Consideration of impacted communities

The Attorneys General support requiring that a state contemplating a less stringent standard of performance for a power plant based on remaining useful life "consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the [source] in determining [the] source-specific BSER[ ] and the degree of emission limitation achievable through application of such BSER[ ]."[409] Consideration of such impacts and benefits is a necessary corollary to the state's obligation to identify such communities as stakeholders through the required meaningful engagement process, as identifying such communities without then considering impacts on them would be pointless.

EPA correctly notes that the additional pollution from such less stringent standards "have the potential to result in disparate health and environmental impacts" to such communities, and that failure to consider such outcomes "would be antithetical to the public health and welfare goals of CAA section 111(d)."[410] Thus, state submission of a plan including a less stringent standard pursuant to the remaining useful life provision must demonstrate that such consideration occurred. Additionally, in such circumstances, the state also could permissibly select a higher-cost standard of performance for a source to benefit communities that would otherwise be harmed by a less stringent standard.

As we previously noted, EPA has ample authority to require such consideration. Congress's inclusion of the "other factors" language in the remaining

[407] *Id.* at 33,385–86.

[408] *Id.* at 33,386.

[409] *Id.*

[410] *Id.*

useful life provision indicates that it envisioned that additional factors aside from remaining useful life could be relevant in determining the appropriate performance standard for individual facilities. Also, section 111(d)'s language directing that EPA "permit" states to consider remaining useful life indicates that the agency has some discretion regarding how states can apply remaining useful life, among other factors, in establishing performance standards. Given that the purpose of regulating stationary source pollution under section 111 is to address emissions that endanger public health and welfare, requiring that states take into account how excess pollution (above the level reflected in application of the best system of emission reduction) may impact the health and welfare of local communities furthers the statutory design. Finally, EPA's oversight authority in ensuring that state plans do a "satisfactory" job of adopting standards that reflect the degree of emission reduction from applying the best system provides additional support for requiring that potential harms from exceeding the emissions guideline be adequately considered.

4. EPA's standard of review of state plans including standards of performance incorporating remaining useful life

The Attorneys General support the Proposed Rule's provisions regarding the EPA's standard of review for state plans including standards of performance that incorporate remaining useful life and other factors. We agree that states carry the burden of making any demonstrations necessary to invoke remaining useful life and to justify any best system or standard of performance that are less stringent than the presumptive standards developed by EPA. We also agree that a state selecting less stringent standards of performance under the remaining useful life provision must meet all other applicable requirements, whether those that might be imposed under the December 2022 proposed rule or otherwise.

The Proposed Rule appropriately requires that, when available, a state must use source- and site-specific information as the basis for applying remaining useful life, because, as EPA points out, remaining useful life can only be invoked for a particular source when there are fundamental differences between EPA's best system and the source's specific circumstances. If such site-specific information is not available, then a state may use other "reliable and adequately demonstrated" sources of information, such as information provided by EPA, permits, environmental consultants, vendors of control technology and inspection reports.[411] In such circumstances, EPA would appropriately require that the state has the

[411] *Id.* at 33,386.

burden of explaining why reliance on the non-site-specific information to establish a less-stringent standard of performance is reasonable.

5. State authority to apply more stringent standards of performance

The Attorneys General support EPA's position that states may use remaining useful life and other factors to impose standards of performance on individual sources that are *more* stringent than EPA's presumptive standards. It is appropriate, as EPA recognized in its recent section 111(d) implementing regulations proposal, for EPA to defer to a state's decision to impose more stringent standards.[412] In the context of that governing standard of review, we agree that a state would have the burden of showing that the standard of performance is more stringent than the presumptive standard, but need not do a source-specific best system evaluation.

EPA provides a list of factors a state may consider in determining whether to impose a more stringent standard of performance based on remaining useful life and other factors, including: effects on local communities, availability of control technologies that allow a particular source to achieve a more stringent standard, and local or state policies and requirements.[413] We agree that these factors are appropriate for such decision making, and further agree that the list is not exhaustive, so that consideration of other relevant factors may be appropriate depending on the circumstances. EPA has authority to require that any such more stringent standards of performance be federally enforceable and meet any other applicable legal requirements.

C. Additional EPA Information to Assist State Plan Development

The Attorneys General have two additional requests for modification of the Proposed Rule to assist states as they develop their section 111(d) plans. First, we respectfully request that, for each state, EPA provide a list of existing facilities subject to the Proposed Rule's emission guidelines for existing sources. In prior rulemakings establishing requirements for existing facilities, such as the Cross State Air Pollution Rule, the Acid Rain Program, the NO_x SIP Call, and the Clean Air Interstate Rule, EPA provided a list of sources that were subject to the new requirements. Doing so for those rules made implementation of the new

---

[412] *See* 87 Fed. Reg. 79,176, 79,204 (Dec. 23, 2022).

[413] 88 Fed. Reg. at 33,386.

requirements by the states much more efficient, and doing so for this Proposed Rule would have the same benefit for state plan development.

Second, the Attorneys General respectfully ask that EPA develop a model section 111(d) state plan for states to use as they develop their own plans incorporating the Proposed Rule's requirements. This will not only assist state agencies, but will also streamline stakeholder involvement if there is a model plan available to serve as the basis for discussion.

CONCLUSION

The Proposed Rule is an important step forward in finally putting in place meaningful carbon pollution limits on new and existing fossil-fueled power plants. The proposal adheres to the Supreme Court's interpretation of the statute set forth in the *West Virginia v. EPA* decision. The Proposed Rule also faithfully implements the Clean Air Act amendments passed as part of last year's Inflation Reduction Act: In developing the rule's emission limits, EPA factored in the economic incentives Congress enacted to encourage certain pollution control technologies. And the agency followed Congress's directive that EPA use its existing authority under section 111 to ensure that power plants substantially reduce their CO_2 emissions.

As discussed in detail above, the Attorneys General support the Proposed Rule as legally sound and necessary to address carbon pollution from power plants that endanger public health and welfare. We also have provided some suggestions for ways in which the Proposed Rule can be strengthened to achieve additional emission reductions while avoiding disproportionate impacts and respecting state authority. With these suggestions in mind, we urge EPA to move promptly to finalize the rule and also to initiate a supplemental rulemaking to limit CO_2 emissions from power plants not regulated in this rulemaking.

Respectfully Submitted,

LETITIA JAMES
Attorney General of New York

/s/ Michael J. Myers

MICHAEL J. MYERS
Senior Counsel for Air Pollution and Climate Change Litigation
ANDREW G. FRANK
Assistant Attorney General
Environmental Protection Bureau
The Capitol
Albany, NY 12224
(518) 776-2400
michael.myers@ag.ny.gov

KRISTIN K. MAYES
Attorney General of Arizona
PAUL PHELPS
Assistant Attorney General
Office of the Attorney General
Environmental Enforcement Section
2005 N. Central Ave.
Phoenix, AZ 85004
602.542.8543
Paul.Phelps@azag.gov

ROB BONTA
Attorney General of California
DENNIS BECK
MYUNG PARK
Supervising Deputy Attorneys General
KAVITA LESSER
THEODORE MCCOMBS
Deputy Attorneys General
300 South Spring Street
Los Angeles, CA 90013
(213) 269-6605
Kavita.Lesser@doj.ca.gov

WILLIAM TONG
Attorney General of Connecticut
MATTHEW I. LEVINE
Deputy Associate Attorney General
SCOTT N. KOSCHWITZ
Assistant Attorney General
Office of the Attorney General
165 Capitol Avenue
Hartford, Connecticut 06106
(860) 808-5250

BRIAN L. SCHWALB
Attorney General for the District of Columbia
DAVID S. HOFFMANN
Senior Assistant Attorney General
Public Advocacy Division
Social Justice Section
400 Sixth St. NW
Washington, D.C. 20001
(202) 442-9889

ANNE E. LOPEZ
Attorney General of Hawaii
LYLE T. LEONARD
Deputy Attorney General
State of Hawaii
Dept. of the Attorney General
465 South King Street, Room 200
Honolulu, Hawaii 96813
(808) 587-3050
lyle.t.leonard@hawaii.gov

KWAME RAOUL
Attorney General of Illinois
JASON E. JAMES
Assistant Attorney General
MATTHEW DUNN
Chief, Environmental Enforcement/
Asbestos Litigation Division
201 W. Pointe Drive, Suite 7
Belleville, IL 62226
(872) 276-3583
jason.james@ilag.gov

AARON M. FREY
Attorney General of Maine
EMMA AKRAWI
Assistant Attorney General
Natural Resources Division
6 State House Station
Augusta, ME 04333
(207) 626-8800
emma.akrawi@maine.gov

ANTHONY G. BROWN
Attorney General of Maryland
JOSHUA M. SEGAL
Special Assistant Attorney General
Office of the Attorney General
200 Saint Paul Place
Baltimore, MD 21202
(410) 576-6446
jsegal@oag.state.md.us

ANDREA JOY CAMPBELL
Attorney General of Massachusetts
TURNER SMITH
Assistant Attorney General & Deputy Bureau Chief
VANNESSA LAWRENCE
Assistant Attorney General & Fellow
Energy and Environment Bureau
One Ashburton Place, 18th Fl.
Boston, MA 02108
(617) 963-2782
turner.smith@mass.gov

DANA NESSEL
Attorney General of Michigan
ELIZABETH MORRISSEAU
Assistant Attorney General
Environment, Natural Resources, and Agriculture Division
6th Floor G. Mennen Williams Building
525 W. Ottawa Street
P.O. Box 30755
Lansing, MI 48909
(517) 335-7664

KEITH ELLISON
Attorney General of Minnesota_
PETER N. SURDO
Special Assistant Attorney General
Minnesota Attorney General's Office
445 Minnesota Street
Town Square Tower Suite 1400
Saint Paul, Minnesota 55101
651.757.1061
Peter.Surdo@ag.state.mn.us

RAUL TORREZ
Attorney General of New Mexico
408 Galisteo St.
Santa Fe, NM 87501

JOSHUA H. STEIN
Attorney General of North Carolina
DANIEL S. HIRSCHMAN
Senior Deputy Attorney General
ASHER P. SPILLER
Special Deputy Attorney General
TAYLOR CRABTREE
Assistant Attorney General
North Carolina Department of Justice
P.O. Box 629
Raleigh, NC 27602
(919) 716-6400

ELLEN F. ROSENBLUM
Attorney General of Oregon
PAUL GARRAHAN
Attorney-in-Charge
STEVE NOVICK
Special Assistant Attorney General
Natural Resources Section
Oregon Department of Justice
1162 Court Street NE
Salem, Oregon 97301-4096
(503) 947-4540
Paul.Garrahan@doj.state.or.us
Steve.Novick@doj.state.or.us

MICHELLE A. HENRY
Attorney General of Pennsylvania
ANN R. JOHNSTON
Assistant Chief Deputy Attorney General
Office of the Attorney General
Civil Environmental Enforcement Unit
Strawberry Square, 14th Floor
Harrisburg, PA 17120
717-497-3678
ajohnston@attorneygeneral.gov

PETER F. NERONHA
Attorney General of Rhode Island
GREGORY S. SCHULTZ
Special Assistant Attorney General
Rhode Island Office of the Attorney General
150 South Main Street
Providence, RI 02908
(401) 274-4400

CHARITY R. CLARK
Attorney General of Vermont
NICHOLAS F. PERSAMPIERI
Assistant Attorney General
Office of the Attorney General
109 State Street
Montpelier, VT 05609
(802) 828-6902
nick.persampieri@vermont.gov

ROBERT W. FERGUSON
Attorney General of Washington
CHRISTOPHER H. REITZ
CAROLINE E. CRESS
Assistant Attorney General
Office of the Attorney General
P.O. Box 40117
Olympia, Washington 98504-0117
(360) 586-4614
chris.reitz@atg.wa.gov

JOSHUA L. KAUL
Attorney General of Wisconsin
GABE JOHNSON-KARP
Assistant Attorney General
Wisconsin Department of Justice
Post Office Box 7857
Madison, WI 53702-7857
(608) 267-8904
johnsonkarpg@doj.state.wi.us

TERESA TAYLOR TATE
City of Boulder
City Attorney
LUIS A. TORO
Senior Counsel
1777 Broadway, 2nd Floor
Boulder, CO 80302
(303) 441-3020
Torol@bouldercolorado.gov

MARY B. RICHARDSON-LOWRY
City of Chicago
Corporation Counsel
BRADLEY R. RYBA
Assistant Corporation Counsel
City of Chicago Department of Law
Regulatory & Contracts Division
2 N. LaSalle Street, Suite 540
Chicago, Illinois 60602
(312) 742-6432
bradley.ryba@cityofchicago.org

KERRY TIPPER
City and County of Denver
City Attorney
EDWARD J. GORMAN
Assistant City Attorney
201 W. Colfax Avenue, Dept. 1207
Denver, Colorado 80202
(720) 913-3275
edward.gorman@denvergov.org

HYDEE FELDSTEIN SOTO
City of Los Angeles
City Attorney
MICHAEL J. BOSTROM
Senior Assistant City Attorney
Los Angeles City Attorney's Office
201 N. Figueroa St., 13th Floor
Los Angeles, CA 90012
(213) 978-1882

HON. SYLVIA O. HINDS-RADIX
City of New York
Corporation Counsel
TESS DERNBACH
Assistant Corporation Counsel
ALICE R. BAKER
Senior Counsel
New York City Law Department
100 Church Street
New York, NY 10007
(212) 356-2320
tdernbac@law.nyc.gov

DIANA CORTES
City of Philadelphia
City Solicitor
VIJYALAKSMI PATEL
Divisional Deputy City Solicitor
City of Philadelphia Law Department
1515 Arch St. 16th Fl
Philadelphia, PA 19102
215-683-5172
vijya.patel@phila.gov

NRDC

APRIL 2023
IB: 23-04-A

ISSUE BRIEF

THE EPA'S POWER PLANT CARBON RULES CAN BE BUILT TO LAST

The EPA has a firm legal basis for strong power sector standards that will accelerate the sector's ongoing reduction of carbon pollution and help meet the urgent threat of climate change.

Authors: Lissa Lynch and David Doniger

The Environmental Protection Agency (EPA) is set to propose new standards for carbon pollution from power plants in the coming weeks.


© Eric Vance / EPA

These standards have been a long time coming.

Fourteen years ago, the EPA determined that carbon dioxide and other greenhouse gases that cause climate change "endanger public health or welfare."[1] That finding triggered Clean Air Act obligations to issue safeguards for climate pollution. So far, the agency has set limits on greenhouse gases from cars and trucks and from oil and gas infrastructure. But power plants—the second-largest source of climate pollution, after transportation—have faced virtually no federal limits. Thanks to coal industry lawsuits, standards that the EPA issued in 2015 never went into effect.[2]

Last year's Supreme Court decision in *West Virginia v. EPA* clarified the bounds of the EPA's Clean Air Act authority to set carbon standards for power plants.[3] And Congress's landmark climate legislation, the Inflation Reduction Act, reaffirmed the EPA's authority and directed the agency to move ahead with such standards.[4]

Setting effective, affordable power plant carbon standards under the Clean Air Act now can ensure that the power industry delivers the emissions reductions needed to help meet the climate crisis.

Time is of the essence. The EPA needs to move expeditiously, proposing power plant carbon standards soon as promised and finalizing them by early next year. This will allow states and power companies to get to work on implementing them, so we can curb this dangerous pollution and safeguard the climate as soon as possible.

This Issue Brief explains:

- the robust legal basis for power plant carbon standards;
- why EPA can set standards based on carbon capture and storage;
- the process for states and companies to comply once the rules are set;
- the background on the transition underway in the power sector;
- the impact of the Inflation Reduction Act; and
- why these carbon standards are necessary.

For more information, please contact:
Mark Drajem
mdrajem@nrdc.org

THE EPA HAS THE AUTHORITY AND RESPONSIBILITY TO ACT

The Clean Air Act has long authorized—indeed, required—the EPA to establish limits on carbon dioxide from new and existing fossil fuel-fired power plants.[5] The agency first set rules for existing power plants in the 2015 Clean Power Plan; however, these rules never took effect because the Supreme Court first stayed them and then the Trump administration repealed them.[6]

Then, in 2022 in *West Virginia v. EPA*, the Supreme Court held that the Clean Power Plan went beyond the agency's authority because it was based not on what is achievable through pollution controls but on "shifting generation"—i.e., replacing coal and gas plants with wind and solar power.

The Court made clear, however, that the EPA retains its "traditional" authority to base standards on technology that "caus[es] plants to operate more cleanly" and "ensur[es] the efficient pollution performance of each regulated source."[7]

CLEAN AIR ACT STANDARDS ON FOSSIL FUEL-FIRED POWER PLANTS

Under Clean Air Act Section 111(b), the EPA sets standards for new plants; these federal standards apply directly to new plants. Under Section 111(d), the agency sets the emission rate that existing plants must meet; these standards are met through state plans. These emission-rate limits must be based on the emission reductions achievable by the "best system of emission reduction" that is available to the plants as evaluated by the EPA, taking into account technical feasibility, cost, and other factors.[8]

Soon after the Supreme Court decision, Congress passed the Inflation Reduction Act, which has three critical features that will affect the upcoming carbon regulations.[9] The act:

- offers significant tax incentives and grants for clean energy;
- expressly designates carbon dioxide and other greenhouse gases as "air pollutants" under the Clean Air Act; and
- amends the Clean Air Act to reaffirm the EPA's authority and direct the agency to issue new standards for power plant carbon dioxide emissions while taking into account the new tax incentives and grants.

One of the technologies supported by the Inflation Reduction Act's tax incentives is carbon capture and storage, which keeps carbon out of the atmosphere by removing it from a plant's smokestack and disposing of it deep underground. As a pollution control technology that makes power plants operate more cleanly, carbon capture and storage falls squarely within the bounds of what the *West Virginia* decision allows EPA to consider in establishing carbon pollution standards. Carbon capture is similar to sulfur dioxide scrubbers and other pollution controls on which the EPA has been basing standards for decades.

Given the EPA's legal authority as defined by the Supreme Court, and the tax incentives and other support enacted by Congress in the Inflation Reduction Act, NRDC is urging the EPA to set standards for both new and existing coal and gas plants based on the emission reductions that can be achieved through carbon capture and storage technology.

Carbon capture and storage can cut power plant carbon dioxide emissions by 90 percent or more—greater than other options such as improving combustion efficiency or co-firing with a lower-carbon fuel.[10]

The EPA's limits should apply to all coal and gas power plants that produce electricity on a regular basis. Standards for existing plants will likely be phased in over a number of years. The EPA could also set less stringent standards for plants that are slated to close in the next few years, and for those that operate infrequently, such as when electricity demand spikes. As explained below, while the EPA should base its standards on the emission limits achievable using carbon capture and storage, each state and each company will have the option to comply in other ways.

HOW CARBON CAPTURE AND STORAGE WORKS

Carbon capture and storage involves three steps: capture, transport, and storage. Pollution control equipment installed on power plants or other industrial facilities (such as ethanol or cement plants) removes carbon dioxide from the flue gases that would otherwise go out the smokestack. Once captured, that carbon dioxide is transported by pipeline for safe, permanent disposal in deep underground geological formations.

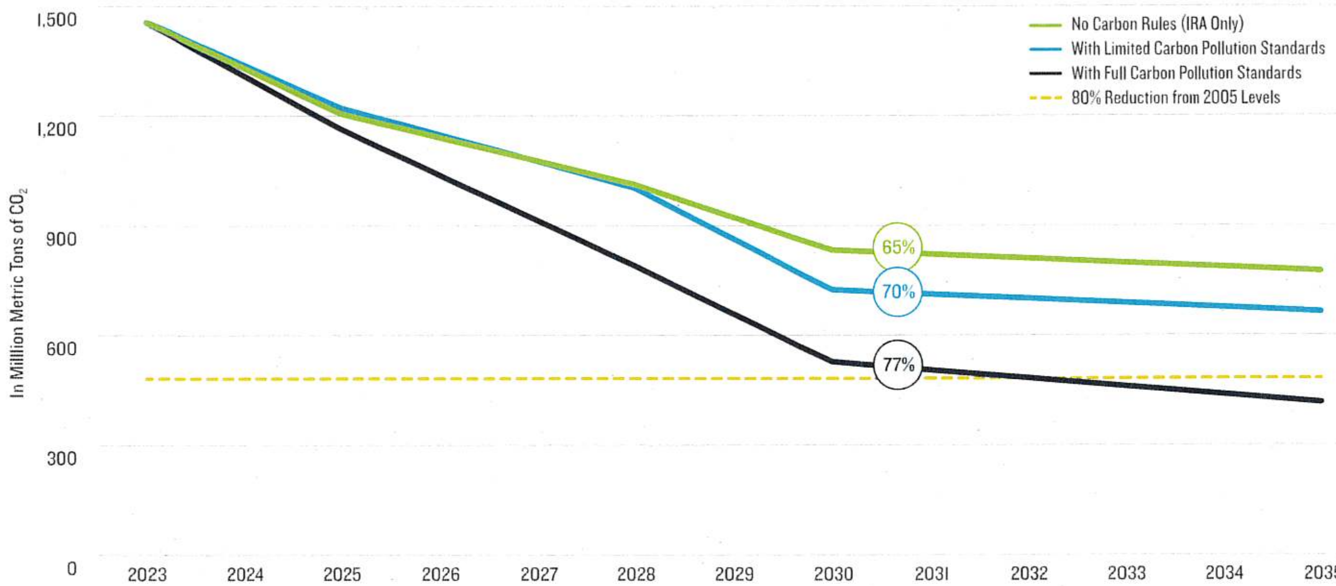
While the technology to capture carbon dioxide has existed for decades, few power plants have used it because there are no limits on their carbon emissions. As new carbon capture and storage projects come online, new rules will also be needed to ensure the safety and soundness of carbon dioxide pipelines and storage sites.

REAL BENEFITS, LOW COSTS

Modeling by NRDC projects that **with the Inflation Reduction Act's clean energy investments plus ambitious but achievable EPA carbon pollution standards, the power sector could reach at least a 77 percent reduction in carbon dioxide emissions by 2030**, relative to the peak in 2005.[11] This is significantly greater than the roughly 65 percent reduction with market trends and tax incentives alone.[12]

Strong carbon pollution standards could bring the power sector very close to the 80 percent reduction target for 2030 that analysis suggests is necessary for the United States to stay on track to meet its climate commitments—and to curb dangerous climate change and protect public health and welfare.[13]

FIGURE 1: PROJECTED U.S. POWER SECTOR EMISSIONS, 2023–2035, WITH FULL, LIMITED, AND NO CARBON STANDARDS



Carbon capture and storage has already been successfully demonstrated on multiple power plants and industrial facilities both in the United States and abroad.[14] With tax incentives defraying a significant share of the cost of installing and operating this technology, NRDC's modeling projects that the costs for power companies and their customers will be well within what is reasonable under the law.

Together with other air pollution standards for power plants, carbon rules will deliver reductions in soot, smog, and mercury, which could prevent hundreds of thousands of premature deaths and provide a huge public health benefit to communities across the nation.[15]

STATES AND COMPANIES WILL DECIDE HOW TO COMPLY

The EPA sets *performance* standards that establish the emission rate that plants have to meet, but does not specify the technology they have to use. So, while the EPA must base those standards on the most effective available technology that can be installed at individual plants—in this case, carbon capture and storage—states and companies are not required to use that technology but instead will have the flexibility to devise their own plans to meet those standards.

While federal standards for new plants apply right away, the Clean Air Act allows each state to adopt its own plan to implement the rules for existing plants. State plans will likely be required within 15 months following the finalization of the EPA's standards. State plans will likely be required within 15 months following the finalization of the EPA's standards, and then those state plans will phase in over the coming years.

The state planning process allows state leaders, utility regulators, companies, and the public to consider the best way to achieve emissions cuts. Some states and companies will choose to install carbon capture technology. Others will decide it makes more sense to operate less frequently and comply with a less stringent standard, or to retire existing fossil plants and invest in new, cleaner (and often cheaper) solar, wind, or battery storage. This will be entirely their decision, not the EPA's.

For plants that do comply with these standards using carbon capture, the EPA must provide for rigorous accounting of carbon pollution from the point of capture to the point of permanent storage, including monitoring of emissions and leaks at all stages and enforcement against any violations. In tandem, the EPA and the Biden administration should also take action to update regulatory safeguards for pipelines and underground storage to ensure that carbon capture and storage projects do not harm communities nearby.

THE POWER SECTOR IS ALREADY CHANGING

These standards will be built on trends already underway in the power sector. Even though the EPA standards reviewed in *West Virginia* never went into effect, the power sector has cut its carbon emissions by more than one-third from the peak level emitted in 2005.[16] Just a decade ago, coal-fired plants generated nearly half the power in the United States, but as coal plants aged and cheaper options grew quickly, coal generation declined; it is now just 20 percent of the total and is likely to dwindle further.[17]

Wind, solar, and battery technologies continue to advance quickly as their costs have plummeted. In fact, renewable energy generated 22 percent of electricity in the United States last year, for the first time outpacing the market shares of both coal and nuclear energy.[18] Solar and wind power are now cheaper to build and run than it is to continue running an old coal plant. In most cases they are also already cheaper than a new gas plant—and may soon be cheaper than existing ones, too.[19]

"With the right policies and technologies, a 100 percent clean energy future can be more than a goal; it can be a reality," the Edison Electric Institute, which represents the nation's investor-owned utilities, reported last year.[20] We think "the right policies and technologies" include these strong EPA standards.

THE IRA WILL SPEED UP THE ENERGY TRANSITION

The Inflation Reduction Act, which President Biden signed into law last year, is the single most important climate legislation in the nation's history. The biggest impact of the law's clean energy investments will be in cutting emissions from the power sector. The bill contains more than $100 billion in clean electricity tax incentives, including a 70 percent increase in the tax credit provided for each ton of carbon captured and sequestered.[21]

Overall, NRDC's modeling found that the tax incentives in the Inflation Reduction Act could double the amount of renewable energy and other low-carbon capacity on the grid by 2030—the fastest and most sustained build-out of renewables and other clean electricity resources in U.S. history.[22]

Private sector analysts agree. "The U.S. IRA provides the most supportive regulatory environment in clean tech history," Goldman Sachs wrote in a March 2023 report that predicted $3 trillion in private and public investments in the coming years.[23]

Several major investor-owned utilities—including DTE Energy, Ameren Missouri, and Duke Energy—have already announced that they will accelerate their transition away from fossil fuels and toward renewable energy, all while saving consumers money.[24] Across the economy, the acceleration of clean energy investments will lower consumers' electricity bills by $60 billion over the next 15 years while adding as many as 169,000 good clean energy jobs.[25] In the six months since the climate bill was passed, companies have announced more than 155 new investments in clean energy totaling $75 billion, according to data compiled by Environmental Entrepreneurs. Those investments alone are expected to create more than 58,000 jobs.[26]

EPA STANDARDS ARE NEEDED TO CUT CARBON

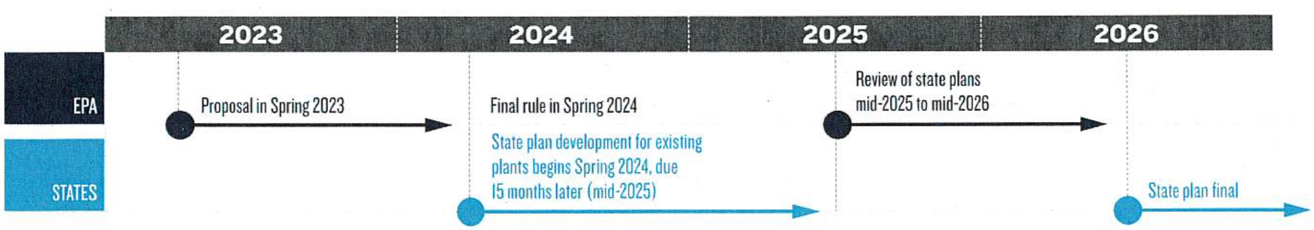
While the trend toward clean energy is clear, plants that continue to use fossil fuels must reduce their emissions commensurate with the best pollution controls available. EPA standards are essential to ensure sufficient reductions of harmful carbon pollution at the pace necessary to address the climate crisis.

These standards will ensure that the power industry is held accountable for their harmful carbon pollution and delivers the emission reductions needed to meet the climate crisis—made clear, once again, in the latest urgent warnings from the world's preeminent climate scientists, the Intergovernmental Panel on Climate Change.[27]

The carbon rules also will give states and companies both the flexibility and the certainty needed to figure out the best pathways to cut this pollution. Even though the standards themselves will be attainable through carbon capture and storage at the individual plant, states and companies will be free to look for the most cost-effective approaches. And clear standards will give industry the regulatory certainty it needs to guide future investment.

These carbon power plant standards will reinforce the changes already underway in the industry. And, together with the Inflation Reduction Act, they will deliver a cleaner grid that saves consumers money and grows the economy, while helping avert the most catastrophic impacts of climate change.

FIGURE 2: TIMELINE FOR EXISTING PLANTS COMPLIANCE



Special thanks to those who reviewed this publication: Jay Duffy of the Clean Air Task Force; Peter Heisler of the Center for Applied Environmental Law and Policy; and Sophia Ahmed, Mark Drajem, Laurie Geller, Ariana Gonzalez, Amanda Levin, and Derek Murrow of NRDC.

ENDNOTES

1 U.S. Environmental Protection Agency (hereinafter EPA), *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, Federal Register vol. 74, no. 239 (Dec. 15, 2009), https://www.epa.gov/sites/default/files/2021-05/documents/federal_register-epa-hq-oar-2009-0171-dec.15-09.pdf.

2 EPA, "Overview of Greenhouse Gases," last updated May 16, 2022, https://www.epa.gov/ghgemissions/overview-greenhouse-gases.

3 *West Virginia v. EPA*, 597 U.S. ___ (2022), https://www.supremecourt.gov/opinions/21pdf/20-1530_n758.pdf.

4 Inflation Reduction Act, Public Law No: 117-169 (Aug. 16, 2022), https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

5 *Massachusetts v. EPA*, 549 U.S. 497 (2007), https://supreme.justia.com/cases/federal/us/549/497/; *American Electric Power Co. v. Connecticut*, 564 U.S. 410 (2011), https://supreme.justia.com/cases/federal/us/564/410/.

6 David Doniger, "2023: A Big Year for Curbing Power Plants' Climate Pollution," NRDC, December 13, 2022, https://www.nrdc.org/bio/david-doniger/2023-big-year-curbing-power-plants-climate-pollution.

7 *West Virginia v. EPA*, 597 U.S. ___ (2022), https://www.supremecourt.gov/opinions/21pdf/20-1530_n758.pdf.

8 42 U.S.C. § 7411, https://www.govinfo.gov/content/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partA-sec7411.htm.

9 Inflation Reduction Act, Public Law No: 117-169.

10 EPA Office of Air and Radiation, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*, April 21, 2022, 39, https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf.

11 Charles Harper et al., *Powering Toward 100 Percent Clean Power by 2035*, NRDC and Evergreen Collaborative, January 23, 2023, https://collaborative.evergreenaction.com/policy-hub/powering-towards-100.

12 Amanda Levin and Jacqueline Ennis, "Clean Electricity Tax Credits in the Inflation Reduction Act Will Reduce Emissions, Grow Jobs, and Lower Bills" NRDC, September 2022, https://www.nrdc.org/sites/default/files/clean-electricity-tax-credits-inflation-reduction-act-ib.pdf.

13 Dan Esposito, *Studies Agree 80 Percent Clean Electricity by 2030 Would Save Lives and Create Jobs at Minimal Cost*, Energy Innovation, September 2021, 9, https://energyinnovation.org/wp-content/uploads/2021/09/Studies-Agree-80-Percent-Clean-Electricity-by-2030-Would-Save-Lives-and-Create-Jobs-at-Minimal-Cost.pdf.

14 Clean Air Task Force, "U.S. Carbon Capture Activity and Project Table," 2023, https://www.catf.us/ccstableus/.

15 Mahdieh Danesh Yazdi et al., "Long-Term Association of Air Pollution and Hospital Admissions Among Medicare Participants Using a Doubly Robust Additive Model," *Circulation* 143, no. 16 (February 22, 2021): 1584–96, https://www.ahajournals.org/doi/10.1161/CIRCULATIONAHA.120.050252.

16 U.S. Energy Information Administration (hereinafter EIA), "Environment," Section 11 in *Monthly Energy Review*, March 23, 2023, https://www.eia.gov/totalenergy/data/monthly/pdf/sec11.pdf.

17 EIA, *Short-Term Energy Outlook*, March 7, 2023, https://www.eia.gov/outlooks/steo/report/electricity.php#:~:text=We%20expect%20renewable%20sources%20will,up%20from%2020%25%20in%202021.

18 EIA, *Electric Power Monthly*, Table 1.1., "Net Generation by Energy Source: Total (All Sectors), 2013–January 2023," January 2023, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_1_01.

19 Lazard, "Levelized Cost of Energy, Levelized Cost of Storage, and Levelized Cost of Hydrogen," October 28, 2021, https://www.lazard.com/research-insights/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen-2021/.

20 Alexander Bond, "EEI [Edison Electric Institute] Comments on EPA's Combustion Turbine White Paper Docket ID No. EPA-HQ-OAR-2022-0289," June 6, 2022, https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0289-0030.

21 Matt Bright, "The Inflation Reduction Act Creates a Whole New Market for Carbon Capture," Clean Air Task Force, August 22, 2022, https://www.catf.us/2022/08/the-inflation-reduction-act-creates-a-whole-new-market-for-carbon-capture/.

22 Levin and Ennis, "Clean Electricity Tax Credits."

23 Goldman Sachs, "Carbonomics: The Third American Energy Revolution," March 2023, subscription required.

24 Eric Lipton, "With Federal Aid on the Table, Utilities Shift to Embrace Climate Goals," *New York Times*, November 29, 2022, https://www.nytimes.com/2022/11/29/us/politics/electric-utilities-biden-climate-bill.html; Ethan Howland, "Ameren Missouri Expects $1.3B in Inflation Reduction Act Tax Credits Will Help Offset Customer Rates by 4.5%," *UtilityDive*, October 14, 2022, https://www.utilitydive.com/news/ameren-missouri-inflationreduction-act-ira-ptcs/634133/.

25 Levin and Ennis, "Clean Electricity Tax Credits."

26 E2 (Environmental Entrepreneurs), "E2: March Sees 28 New Large-Scale Clean Energy Projects, New Projects Announced Since IRA Tops 150", April 5, 2023, https://e2.org/releases/e2-march-sees-28-new-large-scale-clean-energy-projects-new-projects-announced-since-ira-tops-150/.

27 Hoesung Lee et al., *AR6 Synthesis Report: Climate Change 2023*, International Panel on Climate Change, March 2023, https://www.ipcc.ch/report/sixth-assessment-report-cycle/.

ANALYSIS GROUP

Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023

Author:
Susan Tierney

November 7, 2023

Acknowledgments

This is an independent study prepared by the author at the request of Environmental Defense Fund. The Report, however, reflects the analysis and judgment of the author alone.

About the Author

Sue Tierney is a Senior Advisor at Analysis Group, where she has advised a wide variety of organizations. Previously, she served as the Assistant Secretary for Policy at the U.S. Department of Energy, and in Massachusetts she was Secretary of Environmental Affairs, Commissioner at the Department of Public Utilities, and Executive Director of the Energy Facilities Siting Council. She chairs the Board of Resources for the Future. She is a trustee of the Barr Foundation and the Alfred P. Sloan Foundation, a board member at World Resources Institute, and chairs the National Academies' Board on Environmental and Energy Systems. She has served on several National Academies' committees: The Future of the Electric Grid; Net Metering in the Evolving Electricity System; and Accelerating Decarbonization in the U.S. She chaired the Department of Energy's Electricity Advisory Committee, and now chairs the External Advisory Council of the National Renewable Energy Lab. She received her Ph.D. in regional planning from Cornell University

About Analysis Group

Analysis Group is one of the largest economics consulting firms, with over 1,200 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, analytics, strategy, and policy analysis to top law firms, Fortune Global 500 companies, government agencies, and other clients. The firm's energy and climate practice area is distinguished by its expertise in economics, finance, market modeling and analysis, economic and environmental regulation, analysis and policy, and infrastructure development. Analysis Group's consultants have worked for a wide variety of clients, including energy suppliers, energy consumers, utilities, regulatory commissions, other federal and state agencies, tribal governments, power system operators, foundations, financial institutions, start-up companies, and others.

Table of Contents

I. Executive Summary

This report is the latest in a long series of papers, comments and testimony that I have written over the past dozen years on the importance of maintaining electric system reliability as part of the development and implementation of federal regulations addressing air pollution from power plants. This report focuses on the Environmental Protection Agency's newest proposal to regulate greenhouse gas emissions from existing and new fossil generating units under Section 111 of the Clean Air Act.

A common theme in prior instances where EPA issued proposals to control power plant emissions is that industry stakeholders raise concerns that the proposal, if adopted by EPA, would jeopardize electric system reliability and thus conflict with the industry's obligation to provide around-the-clock electricity supply to consumers. Such red flags were raised in 2010 and 2011 about EPA's regulations to control mercury emissions, other hazardous air pollutants and the interstate transport of air pollution. Concerns were raised in the 2013-2015 period when EPA proposed regulations to control emissions of greenhouse gases from fossil-fueled power plants.

In each of those contexts, I authored or co-authored reports and provided testimony and commentary that acknowledged the critical importance of electric system reliability and described the various tools available to the industry to ensure the reliable supply of power even as owners of fossil-fueled generating units were required to take steps to reduce their emissions.[1] Some of these tools were written into the design of EPA's proposals themselves, because in each instance, EPA took into consideration the need to keep the lights on even as power plants complied with new regulations. Other tools are standard elements of the reliability tool kits long available to players in the electric industry.

In every instance in the past dozen years, the industry predictably stepped up to ensure that reliability was not compromised – mainly because these many tools are available and because power plant owners, reliability organizations, regulators, other public officials, and a wide range of other stakeholders took myriad actions to ensure that the grid as a whole performed its essential public service functions.

A common theme in past EPA efforts to control air pollution from existing power plants is concern that implementation of new rules will harm electric system reliability.

Yet past implementation of such power-plant emissions regulations has not led to such outcomes, in large part due to the existence and use of various tools to ensure reliable operations of the system.

In fact, in spite of early industry concerns that EPA's 2015 Clean Power Plan would introduce reliability problems if it went into effect (which it never did, after its implementation was stayed by the court and replaced by EPA in 2019), power-sector carbon dioxide emissions dropped to 34 percent below 2005 levels (thus exceeding the Clean

[1] These writings are referenced with citations in the body of this report.

Power Plan's goal of reducing such emissions by 32 percent by 2030).[2] There is no indication that such emission reductions have led to reliability events (although there is clear indication that extreme weather related to climate change has exacerbated them).

Reduction of power-sector carbon-dioxide emissions is the result of many changes in the electric industry over the past decade. The portfolio of generating resources has transitioned, with retirements of significant coal-fired generating capacity, with gas-fired power plants now providing the largest share of electricity supply and with wind and solar energy making up increasing percentages of electricity generation.[3] Electricity demand – in terms of year-long use and peak demand – has begun to grow in most parts of the country. Fundamental market forces, federal and state policies, and consumer preferences are principal drivers of such changes.[4] Extreme weather events, including frigid cold, droughts, heat waves, wildfires, torrential downpours, and flooding events, have disrupted energy infrastructure, including on the electricity grid (and notably among fossil generating units and their sources and transmitters of natural gas supply).[5]

Many stakeholders have commented that in light of these circumstances, the EPA's recent proposal errs in a number of ways, especially by not allowing more time for compliance and more expansive safety valves to provide more flexibility in the event that reliability problems arise.[6]

Many stakeholders have raised concerns that EPA's newest proposal to regulate GHG emissions from new and existing power plants could jeopardize reliability. Commenters call for longer compliance periods, greater flexibility in implementation and use of broader reliability safety valves.

The EPA regulation, however, reflects the agency's careful attention to reliability and includes many elements designed to ensure that the nation can enjoy the benefits of reduced aire pollution and operational reliability.

Although some of the particulars of the current context are different from those in the past, there are many reasons to feel reassured that this new EPA rule will not jeopardize electric system reliability.

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

[3] National Academies of Sciences, Engineering and Medicine, "The Future of Electric Power in the United States," 2021 (hereafter "NASEM Future of Electric Power"), https://nap.nationalacademies.org/download/25968.

[4] Susan Tierney, "U.S. Coal-Fired Power Generation: Market Fundamentals as of 2023 and Transitions Ahead," August 8, 2023 (Corrected), https://www.analysisgroup.com/globalassets/insights/publishing/2023-tierney-coal-generation-report.pdf.

[5] Susan Tierney, Testimony before the U.S. Senate Committee on the Budget, Hearing on "Beyond the Breaking Point: The Fiscal Consequences of Climate Change on Infrastructure," July 26, 2023 (hereafter "Tierney Budget Committee Testimony 2023"), https://www.budget.senate.gov/imo/media/doc/Hon.%20Susan%20F.%20Tierney%20-%20Testimony%20-%20Senate%20Budget%20Committee.pdf.

[6] *See* for example the following sets of comments submitted to the Environmental Protection Agency in Docket EPA-HQ-OAR-2023-0072: American Public Power Association, Comments, August 9, 2023, https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0566; National Rural Electric Cooperative Association, Comments, August 8, 2023, https://www.electric.coop/wp-content/uploads/2023/08/111-NPRM-Comments-NRECA.pdf; Edison Electric Institute, Comments, August 8, 2023, https://www.eei.org//-/media/Project/EEI/Documents/Resources-and-Media/TFB/EEIComments_111Rules_FINAL_080823.pdf; Power Generators Air Coalition, August 8, 2023 (hereafter "PGen Comments"), https://pgen.org/wp-content/uploads/2023/08/PGen-Comments-on-EPAs-Proposed-GHG-Emission-Standards-and-Guidelines-for-Fossil-Fuel-Fired-EGUs-with-attachments.pdf; Electric Power Supply Association, "Comments", August 5, 2023. https://epsa.org/wp-content/uploads/2023/08/EPSAComments_EPA111_August2023.pdf.

First, the electricity reliability institutions, tools and processes in place today are as good as, if not better than, those in place a decade ago. In addition to its important and continually updated reliability assessments of reliability conditions and outlooks, the North American Electric Reliability Council has instituted new assessments[7] and tools to identify reliability risks and opportunities and to recommend approaches to mitigate them.

Second, significant attention is already being paid by federal and state legislators, reliability organizations, and regulators and other public officials to address confounding circumstances – including gas/electric coordination issues, cybersecurity risks, transitions in generation portfolios, need to enhance the resilience of energy infrastructure to extreme weather events, transmission expansion challenges, wholesale market rule considerations, utility forecasting and planning, equity concerns[8] – so as to assure the grid is fit for purpose in the years ahead.

Third, the EPA proposal to curb GHG emissions from new and existing electric generating units itself includes multiple features to accommodate flexibilities in implementation and compliance-related reliability concerns. These elements of the proposal include: the fact that emissions limits apply only to some subcategories of existing generating units; the long lead times for compliance (with varied deadlines for units with different "operating horizons" and capacity factors); and the ability of states to design implementation plans with a degree of allowance trading and banking; and the commitment of the Department of Energy to use its authorities in a circumstance where compliance at a particular unit might trigger a local reliability concern. There is also the agency's existing system emergency exclusion for reliability.[9]

Unquestionably, there are many other reliability risks that have been identified by NERC, FERC and other organizations.

There is significant work underway to address such risks and needs to continue in earnest, regardless of finalization of the EPA regulation and its eventual implementation in the years ahead.

Unquestionably, the important reliability risks that currently affect the electric industry must be addressed and there is significant work underway to do so.[10] Regardless of requirements that developers of new gas-fired power plants and owners of existing fossil fuel power plants comply with new GHG emission reduction requirements, the electric industry must take the steps necessary to ensure reliability given the many other changes already underway and that are affecting the nation's energy transition.

[7] NERC, "2023 ERO Reliability Risk Priorities Report" (RISC Approved 7-24-2023; NERC Board approved 8-17-2023) (hereafter "NERC Reliability Risk Priorities Report 2023"), https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf.

[8] NASEM Future of Electric Power; NASEM 2023 Decarbonization Study.

[9] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-TTTT.

[10] NERC Reliability Risk Priorities Report 2023.

II. Background and Introduction

EPA's May 2023 proposal to regulate GHG emissions from existing and new fossil-fueled power plants has prompted thousands of public comments from stakeholders.[11] Among other things, various commenters from the power industry raise concerns about the implications of the proposed rule for electric system reliability, in part due to the potential for premature retirements of existing fossil-fueled electric generating units, operational constraints on some generating units, and difficulties in adding new gas-fired generating units.[12]

Some commenters point to what they view as technical flaws in the EPA's modeling of the industry's response to the proposed regulation, which in their view gives rise to reliability concerns. Other comments relate to market factors and considerations that the commenters view as inconsistent with EPA assumptions.

Comments address a wide variety of issues, only a small portion of which are addressed here in this report. This paper focuses on the following topics:

- Section III contains a high-level overview of the EPA proposal, especially as it intersects with electric-system reliability.
- Section IV provides context for considering the reliability-related comments and industry reactions to EPA's proposed regulations.
- Section V addresses my responses to thematic and technical concerns raised by stakeholders with regard to reliability issues.

---

[11] As of October 24, 2023, the EPA reports that 8,034 comments have been posted to Docket EPA-HQ-OAR-2023-0072, and that the agency has received a total of 1,293,352 comments on its proposal. https://www.regulations.gov/docket/EPA-HQ-OAR-2023-0072.

[12] *See* for example the following sets of comments submitted to the Environmental Protection Agency in Docket EPA-HQ-OAR-2023-0072: American Public Power Association, Comments, August 9, 2023, https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0566; National Rural Electric Cooperative Association, Comments, August 8, 2023, https://www.electric.coop/wp-content/uploads/2023/08/111-NPRM-Comments-NRECA.pdf: Edison Electric Institute, Comments, August 8, 2023, https://www.eei.org//-/media/Project/EEI/Documents/Resources-and-Media/TFB/EEIComments_111Rules_FINAL_080823.pdf; Comments of the Power Generators Air Coalition on the U.S. EPA New Source Performance Standards for GHG Emissions, Docket No. EPA-HQ-OAR-2023, 0072, August 8, 2023 (hereafter "PGen Comments"), https://pgen.org/wp-content/uploads/2023/08/PGen-Comments-on-EPAs-Proposed-GHG-Emission-Standards-and-Guidelines-for-Fossil-Fuel-Fired-EGUs-with-attachments.pdf; Electric Power Supply Association, "Comments", August 5, 2023. https://epsa.org/wp-content/uploads/2023/08/EPSAComments_EPA111_August2023.pdf.

III. Overview: EPA's Proposed Regulation for GHG Emissions from Fossil Units

On May 23, 2023, the Federal Register published EPA's proposal under Section 111 of the Clean Air Act to establish new source performance standards ("NSPS") for GHG emissions from new fossil-fueled stationary combustion turbine ("CT") electric generating units ("EGUs"), existing coal-fired EGUs, and from large and frequently used existing fossil CTs.[13] (Smaller existing fossil CTs (whether frequently or infrequently used) are not covered by this proposed rule.)

The Federal Register notice (often referred to as the "Preamble") describes the proposal in detail, identifies topics for comment and is accompanied by several other documents including a Regulatory Impact Assessment.[14] EPA's May 2023 proposal anticipates that the agency will publish final emission guidelines in June 2024, with state plans due to the agency 24 months later (e.g., June 2026).[15]

EPA states that it "has designed these proposed standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity" and is "taking into account the cost of the reductions, non-air quality health and environmental impacts, and energy requirements." [16]

More specifically, EPA states that it "has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals and is confident that these proposed NSPS and emission guidelines – with the extensive lead time and compliance flexibilities they provide – can be successfully implemented in a manner that preserves the ability of power companies and grid operators to maintain the reliability of the nation's electric power system."[17]

In addition to its regular interactions with federal agencies involved in matters affecting the electric industry, EPA drafted its proposal after two rounds of broad stakeholder engagement, including a pre-proposal docket that solicited public input prior design of the proposed regulation.[18] EPA's interagency consultations included

---

[13] This description of the EPA's proposal draws upon the Preamble published in the Federal Register 33240 Federal Register / Vol. 88, No. 99 at 33240, Tuesday, May 23, 2023, Proposed Rule (for Environmental Protection Agency, 40 CFR Part 60, [EPA–HQ–OAR–2023–0072; FRL–8536–02–OAR], RIN 2060–AV09, New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule) (hereafter referred to as the "Preamble"), https://www.govinfo.gov/content/pkg/FR-2023-05-23/pdf/2023-10141.pdf.

[14] See the "browse documents" tab at EPA's website for Docket EPA-HQ-OAR-2023-0072, https://www.regulations.gov/docket/EPA-HQ-OAR-2023-0072/document.

[15] Preamble, at 33372.

[16] Preamble, at 33243.

[17] Preamble, at 33246.

[18] Preamble, at 33276-77. "In the first round of outreach, in early 2022, the EPA sought input in a variety of formats and settings from States, Tribal nations, and a broad range of stakeholders on the state of the power sector and how the Agency's regulatory actions affect those trends. This outreach included State energy and environmental regulators; Tribal air regulators; power companies and trade associations representing investor-owned utilities, rural electric cooperatives, and municipal power agencies; environmental justice and community organizations; and labor, environmental, and public health organizations. A second round of outreach took place in August and September 2022, and focused on seeking input specific to this rulemaking. The EPA asked to hear perspectives, priorities, and feedback around five guiding questions, and encouraged public input to the nonregulatory docket (Docket ID No. EPA–HQ–OAR–2022–0723) on these questions as well."

discussions with the Department of Energy ("DOE") that covered reliability and technology issues among other things. Additionally, EPA described its resource adequacy assessment in a Resource Adequacy Technical Support Document.[19]

The proposed rule addresses emissions from certain types of fossil EGUs: new natural gas CT units (including in simple-cycle and combined-cycle configurations); existing fossil steam units (i.e., coal, natural gas, oil); and certain existing gas CTs.[20] The compliance deadlines vary for different types of units depending upon a number of factors relating to size, technology (i.e., steam unit versus combustion turbine) and operating characteristics (e.g., capacity factor, expected time period during which the unit would continue to remain in service), as explained further below.

In setting deadlines, EPA acknowledged that such factors affect the economics of recovering the costs of control technologies[21] and explained that during the early engagement process, "industry stakeholders requested that the EPA '[p]rovide approaches that allow for the retirement of units as opposed to investments in new control technologies, which could prolong the lives of higher-emitting EGUs; this will achieve maximum and durable environmental benefits.' Industry stakeholders also suggested that the EPA recognize that some units may remain operational for a several-year period but will do so at limited capacity (in part to assure reliability), and then voluntarily cease operations entirely."[22]

The proposed rule includes standards for new stationary CT units (which EPA states are likely to be fueled by natural gas) with facilities having different projected levels of output associated with "base load" operations (defined as units with a capacity factor greater than ~50 percent), "intermediate load" operations (units with a capacity factor of 20-~50 percent) and "low load" operations (units with a capacity factor less than 20 percent)).[23]

Between now and 2032, base load and intermediate units would need to meet emissions levels of highly efficient combined cycle ("CC") and CT technology, respectively. Starting in 2032, intermediate units would need to meet emissions associated co-firing with 30-percent low-GHG hydrogen ("H2"). In 2032 and beyond, base-load units would have standards consistent with two options (which EPA calls "pathways"): (a) a "Low-GHG Hydrogen Pathway" with an emissions standard based on co-firing with 30-percent low-GHG H2 starting in 2032, and with

[19] See the EPA "TSD – Resource Adequacy," ID EPA-HQ-OAR-2023-0072-0034 (hereafter referred to as the "Resource Adequacy TSD"), at https://www.regulations.gov/docket/EPA-HQ-OAR-2023-0072/document.

[20] "The EPA is not proposing to revise the NSPS for newly constructed or reconstructed fossil fuel-fired steam generating units, which it promulgated in 2015 (80 FR 64510; October 23, 2015). This is because the EPA does not anticipate that any such units will construct or reconstruct and is unaware of plans by any companies to construct or reconstruct a new coal-fired EGU. The EPA is proposing to revise the standards of performance that it promulgated in the same 2015 action for coal-fired steam generators that undertake a large modification (*i.e.,* a modification that increases its hourly emission rate by more than 10 percent) to mirror the emissions guidelines, discussed below, for existing coal-fired steam generators. This will ensure that all existing fossil fuel-fired steam generating sources are subject to the emission controls whether they modify or not." Preamble, at 33245.

[21] Preamble, at 33245.

[22] Preamble, at 33245.

[23] EPA, "Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions form Fossil Fuel-Fired Electric Generating Units," May 11, 2023, https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf; EPA, "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants," Webinar for Communities with Environmental Justice Concerns and Members of Tribal Nations, June 2023, https://www.epa.gov/system/files/documents/2023-06/111%20Power%20Plants%20Stakeholder%20Presentation_Webinar%20June%202023.pdf.

emissions rates consistent with co-firing with 96-percent low-GHG H2 starting in 2038; or (b) a "CCS Pathway" tied to emissions levels of 90 percent carbon capture and storage starting in 2035. These standards are shown in Table 1, along with the timing and character of standards for existing units (explained further below).

Table 1:
EPA Proposed Emissions Guidelines and Standards for Various New and Existing Electric Generating Units

	New (or Modified) Units					Existing Units				
	New Fossil CTs (Likely natural gas units) with compliance starting on in-service date				New, Recon-structed or Modified steam units (Likely coal)	Fossil CTs >300 MW and CF>50%* (Likely gas)	Fossil Steam Units** (coal, gas, oil units)		Fossil Steam Units** (coal units)	
	CF <20%	CF 20-50%	CF >~50%				If cease operations by 2032	If cease operations by 2035	If cease operations by 2040	If operate beyond 2040
2024	Final rule (State Implementation Plans due 24 months later)									
2025–2029 (**2026: SIPs due**)	Use of low-CO_2 fuel	Use of efficient current CT technology	Use of efficient current CC technology		2015 standards remain in place***					
2030–2031							Routine O&M (no emissions rate increase)	Routine O&M, no emissions rate increase, capacity factor <20%	Co-firing 40% natural gas (with 16% reduction in emissions rate)	CCS with 90% capture of CO_2
2032–2034		Add co-firing with 30% low-GHG H2	Co-firing with 30% low-GHG H2	Efficient CC units		Same as New Fossil CCs with CF >50% (with two options)				
2035–2037				CCS with 90% capture						
2038–2039			Co-firing with 96% low-GHG H2							
2040										
2041+										

Acronyms:

CC (combined cycle); CCS (carbon capture and storage); CF (capacity factor); GHG (greenhouse gas); CO_2 (carbon dioxide); CT (combustion turbine); H2 (hydrogen); MW (megawatt); O&M (operations and maintenance); SIP (State Implementation Plan)

Notes:

Gray-shaded areas indicate years when such plants will no longer operate due to an enforceable commitment from the unit's owner.

* Existing gas-fired CTs: Smaller (<300MW) with capacity factor below 50% not covered by the current EPA GHG proposal.

** Existing gas or oil-fired boilers: routine O&M with no increase in emissions rate

*** Current standards remain in place until such time as EPA makes a new proposal

https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf;
https://www.epa.gov/system/files/documents/202306/111%20Power%20Plants%20Stakeholder%20Presentation_Webinar%20June%202023.pdf.

Large, frequently used existing fossil combustion turbine units would be required to follow those same emissions guidelines after 2032. For modified and reconstructed fossil steam units (which are likely to be coal-fired generating units), existing emissions standards established in 2015 remain in place.

For existing steam and combustion turbine generating units, EPA's Preamble summarizes the compliance deadlines by subcategory of generating units as follows (with emphasis and formatting adjustments added from the original text so as to focus on treatment of different categories of electric generating units):

> In response to this industry stakeholder input and recognizing that the cost effectiveness of controls depends on the unit's expected operating time horizon, which dictates the amortization period for the capital costs of the controls, **the EPA believes it is appropriate to establish subcategories of existing steam EGUs that are based on the operating horizon of the units**.
>
> The EPA is proposing that for **[existing steam] units that expect to operate in the long-term** (*i.e.,* those that plan to operate past December 31, 2039), the BSER [Best System of Emissions Reduction] is the use of CCS [carbon capture and storage] with 90 percent capture of CO_2 with an associated degree of emission limitation of an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis). As explained in detail in this proposal, CCS with 90 percent capture of CO_2 is adequately demonstrated, cost reasonable, and achieves substantial emissions reductions from these units.
>
> The EPA is proposing to define **coal-fired steam generating units with medium-term operating horizons** as those that (1) Operate after December 31, 2031, (2) have elected to commit to permanently cease operations before January 1, 2040, (3) elect to make that commitment federally enforceable and continuing by including it in the State plan, and (4) do not meet the definition of near-term operating horizon units. **For these medium-term operating horizon units**, the EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis with an associated degree of emission limitation of a 16 percent reduction in emission rate (lb CO2/MWh-gross basis)….
>
> For **[existing fossil steam] units with operating horizons that are imminent-term**, *i.e.,* those that (1) Have elected to commit to permanently cease operations before January 1, 2032, and (2) elect to make that commitment federally enforceable and continuing by including it in the State plan, the EPA is proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO2/MWh-gross basis). The EPA is proposing the same BSER determination for units in the near-term operating horizon subcategory, *i.e.,* units that (1) Have elected to commit to permanently cease operations by December 31, 2034, as well as to adopt an annual capacity factor limit of 20 percent, and (2) elect to make both of these conditions federally enforceable by including them in the State plan.….
>
> The EPA is also proposing emission guidelines for **existing natural gas-fired and oil-fired steam generating units**. Recognizing that virtually all of these units have

> limited operation, the EPA is, in general, proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate….[24]

Under Section 111(d) and its application to existing electric generating units, states must submit plans to EPA that provide for the establishment, implementation and enforcement of standards of performance for existing sources, with those state-specific standards being at least as stringent as EPA's final guidelines. States may take into account remaining useful life and other factors when applying standards of performance to individual existing sources. EPA is proposing that states submit their State Implementation Plans ("SIPs") within 24 months after EPA finalizes the new rule.

EPA's Preamble explains the agency's approach to considering the implications of the proposed rule for the ability of the grid to maintain resource adequacy and electric system reliability:[25]

> Finally, the EPA has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals and is confident that these proposed NSPS and emission guidelines – with the extensive lead time and compliance flexibilities they provide – can be successfully implemented in a manner that preserves the ability of power companies and grid operators to maintain the reliability of the nation's electric power system. The EPA has evaluated the reliability implications of the proposal in the *Resource Adequacy Analysis* TSD; conducted dispatch modeling of the proposed NSPS and proposed emission guidelines in a manner that takes into account resource adequacy needs; and consulted with the DOE and the Federal Energy Regulatory Commission (FERC) in the development of these proposals. Moreover, the EPA has included in these proposals the flexibility that power companies and grid operators need to plan for achieving feasible and necessary reductions of GHGs from these sources consistent with the EPA's statutory charge while ensuring grid reliability….[26]

EPA concluded that its proposed emissions standards for existing gas-fired and coal units and new gas-fired units would have "very little incremental impact on resource adequacy" relative to the agency's modeled baseline (without the proposed standards in place). EPA estimated, for example, that "the emission guidelines for existing gas would cover 36.8 GW of natural gas EGUs, which represents 7.7 percent of total natural gas capacity in 2035"

[24] Preamble, at 33245-46.

[25] EPA states in the Resource Adequacy Technical Support Document: "As used here, the term resource adequacy is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region, while reliability includes the ability to deliver the resources to the loads, such that the overall power grid remains stable. This document is meant to serve as a resource adequacy assessment of the impacts of the final rule and how projected outcomes under the final rule compare with projected baseline outcomes in the presence of the [Inflation Reduction Act]." Resource Adequacy TSD, page 2.

[26] Preamble, at 33246.

and with "only a fraction of this amount ha[ving] a direct effect on resource adequacy" (i.e., meeting peak demand).[27]

The many provisions within EPA's proposed rule that also together address assurance of electric system resource adequacy and operational reliability include a combination of proposal elements and process attributes that provide many ways to address reliability concerns (i.e., at least a decade and in many cases longer to mitigate concerns). These elements include:

- Periods of governmental and stakeholder engagement prior to the 2023 Federal Register notice of the proposal, with discussions of potential interactions of the proposal and electric system reliability.

- Two-year lead times after EPA finalizes the rule in which states prepare their SIPs and identify potential ways (including through emissions averaging and trading) to provide compliance flexibility for affected generating units.

- Various time frames during which existing coal-fired generating units come into compliance with the emissions standards, depending on their operating horizons and output levels.

    - Coal units that commit to close by 2032 have no operating standards applied to them (except for routine operations and maintenance ("O&M")). This is nearly 10 years after notice of the proposed rule, and 8 years after the expected final rule.
    - Coal units that commit to close by 2034 and have low capacity factors (below 20 percent) have no operating standards applicable to them except for continued routine O&M. This is a decade after the expected year in which EPA finalizes the rule.
    - Coal units with longer anticipated retirement dates beyond 2034 have options for complying with the proposed standards – including through co-firing with natural gas and through eventually adding carbon capture and storage.

- Various options for gas-fired combustion turbines to comply:

    - New low load units (less than 20-percent capacity factor) are subject to standards equivalent to use of lower emitting fuels.
    - In the initial phase of compliance, new intermediate (20 to ~50 percent capacity factor) and baseload units (over ~50 percent capacity factor) are subject to GHG emissions rates tied to the most efficient CT and CC technologies, respectively, that are currently available (something that is likely to be efficient from an investor's point of view in any event).

[27] Resource Adequacy TSD, page 7. Further, EPA explained: "The total available capacity is needed, at most, for only a fraction of the year [i.e., to meet peak demand]; most facilities can run at significantly less than full utilization throughout the year without any impact on resource adequacy or system reliability. Moreover, even those EGUs [electric generating units] that operate at 50% annual capacity factor or below, and therefore avoid any requirements under the proposed emission guidelines for existing gas, could operate at higher utilization during periods of system need without exceeding a 50% capacity factor on an annual basis. Grid planners and system operators assign high capacity accreditation values to natural gas-fired EGUs that operate at a wide range of capacity factors. Therefore, those EGUs that choose to reduce utilization to at or under 50% would receive full capacity accreditation."

- In later years, new intermediate units are subject to lower GHG emissions standards equivalent to co-firing with low-GHG-emitting hydrogen, while new baseload units are subject to standards equivalent to co-firing low-GHG hydrogen *or* use of carbon capture and storage technology.
- Existing units that are relatively large (over 300 MW) and that operate frequently (over 50-percent capacity factor) meeting similar emissions standards as new baseload units during those same post-2032 time periods.
- Existing gas-fired combustion turbines (operating as stand-alone peaking units or in combined cycle configurations) that are either smaller (which would cover most units[28]) or operate at less than 50 percent capacity factor are not covered by these proposed rules.

[28] According to the Energy Information Administration ("EIA"), most CT generating units that are in operation as of August 2023 and owned by an electric utility or an independent power product are less than 300 MW in size:

- There are approximately 1,750 gas-fired combustion turbine generating units. Only two of these units are above 300 MW in size (nameplate capacity). The total nameplate capacity of all of these units is 143,074 MW (with summer capacity rating of 120,420 MW). The average size is 81 MW (nameplate capacity), or 67 MW summer capacity rating.
- There are an additional 1540 gas-fired combined cycle generating units, of which 181 units are over 300 MW in size (nameplate capacity). The total nameplate capacity of all of these units is 291,340 MW (with summer capacity rating of 263,460 MW). The average size is 189 MW (nameplate capacity), or 171 MW summary capacity rating.

EIA, Preliminary Monthly Electric Generator Inventory, EIA 860M data for August 2023, https://www.eia.gov/electricity/data/eia860m/.

IV. Context: Reliability Concerns Raised in Prior EPA Regulatory Proposals

A predictable complement to an EPA proposal to regulate air pollutants from fossil fueled generating units is a call from various stakeholders to ensure that the new regulation would not jeopardize electric system reliability – something often accompanied by requests to modify and/or delay the proposed regulation.

This has happened on numerous occasions over the past dozen years, I have been involved in assessing reliability concerns in these instances, an experience that – along with my continued participation in a variety of fora involved with electric industry transitions – has given me a perspective on how to think about the concerns currently being raised about EPA's May 2023 proposal to regulate GHG emissions from fossil units.

Here are examples of those prior instances.

- In the early 2010s,[29] EPA published its draft Clean Air Interstate Rule ("CAIR"), which would regulate NO_x and SO_2 emissions in dozens of Eastern states and go into effect at the start of 2012. This rule was eventually replaced by the Cross-State Air Pollution Rule ("CSAPR"), issued by EPA in July 2011 for implementation starting in 2015. During the approximately same period, EPA was developing rules to regulate hazardous air pollutants and mercury emissions from power plants, which also affected emissions from fossil fueled generating units. The latter eventually took the form of the proposed Mercury and Air Toxics Standards (May 2011).[30] EPA proposed new source performance standards for new stationary sources in April 2012.[31]
- At the time, reliability concerns were raised by power plant owners, trade associations, and reliability organizations.
    - I co-authored three reports[32] aimed at assessing the implications of anticipated EPA air-emission regulations for electric-sector reliability, all of which concluded that the electric industry could comply with these EPA regulations without threatening electric system reliability. As I explained in the third of those reports:

        > The first report, published in August 2010, concluded that the electric industry is well-positioned to comply with EPA's proposed air regulations without threatening electric system reliability. The summer 2011 update, published in August,

[29] https://www.epa.gov/sites/default/files/2016-10/documents/2013_full_report_0.pdf; https://www.epa.gov/Cross-State-Air-Pollution/overview-cross-state-air-pollution-rule-csapr#:~:text=This%20rule%20requires%20certain%20states,soot%20pollution%20in%20downwind%20state.

[30] https://www.epa.gov/mats/epa-proposes-mercury-and-air-toxics-standards-mats-power-plants.

[31] https://www.govinfo.gov/content/pkg/FR-2012-04-13/pdf/2012-7820.pdf.

[32] Michael J. Bradley, Susan Tierney, Christopher Van Atten, Paul Hibbard, Amlan Saha, and Carrie Jenks, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," August 2010, https://www.npcc.org/content/docs/public/program-areas/rapa/government-regulatory-affairs/2010/mjbaandanalysisgroupreliabilityreportaugust2010.pdf; Michael J. Bradley, Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Summer 2011 Update," June 2011, https://obamawhitehouse.archives.gov/sites/default/files/omb/assets/oira_2060/2060_06132011-2.pdf; Michael J. Bradley, Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Fall 2011 Update," November 2011, https://grist.org/wp-content/uploads/2011/11/reliabilityupdatenovember202011.pdf.

supplemented the original analysis in light of new information and reaffirmed the prior report's major conclusion that the electric industry can comply with EPA's air pollution rules without threatening electric system reliability. The August report noted that proper planning and implementation can secure important public health benefits, reliable electric service, and efficient market outcomes. Th[e] "Fall 2011 Update" focuse[d] on the many tools that are available for ensuring electric reliability as companies comply with the EPA rules by installing modern pollution control systems, utilizing allowances or retiring portions of the fleet that are uneconomic to retrofit. Federal and state regulators agree that the industry has the tools to maintain electric system reliability even in the face of coal plant retirements. In testimony to Congress, FERC Commissioner John Norris stated "[i]n short, based on the information I have reviewed to date on EPA's regulations, I am sufficiently satisfied that the reliability of the electric grid can be adequately maintained as compliance with EPA's regulations is achieved.[33]

- I also wrote a "field guide" to the many industry studies assessing the impacts of EPA regulations on power supply and co-authored a peer review of an electric industry analysis of the potential impacts of environmental regulation on the U.S. generation fleet, and concluded that the report was based on "worst-case assumptions which have not materialized..."[34]

- I testified before the U.S. Senate Environment and Public Works Committee at its June 30, 2011 Oversight Hearing on Review of EPA Regulations Replacing the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), where I explained the reasons for concluding that the electric "industry will respond innovatively and effectively, and with confidence that Americans can get the benefit of clean air and reliable electricity."[35] *Because most of these reasons are still relevant today, I repeat this summary here:*

  The U.S. electric industry has a proven track record of doing what it takes to provide the nation with reliable electricity. Regulated electric utilities, competitive electric companies, grid operators, and regulators have a strong mission orientation, along

[33] Michael J. Bradley, Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Fall 2011 Update," November 2011, https://grist.org/wp-content/uploads/2011/11/reliabilityupdatenovember202011.pdf.

[34] Susan Tierney May 17, 2011 letter to EPA Administrator Lisa Jackson, with three attachments: (a) S. Tierney and C. Cicchetti, "The Results in Context: A Peer Review of EEI's "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet," May 2011; (b) S. Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," January 18, 2011; and (c) S. Tierney, "EPA Regulations, Power Generation Capacity & Reliability," MIT Center for Energy & Environmental Policy Research Workshop – May 5, 2011," https://policyintegrity.org/documents/Tierney_letter_to_EPA_Administrator_Jackson_5-17-2011_-_with_attachments.pdf.

[35] Susan F. Tierney, "Summary of Testimony Before the U.S. Senate Environment and Public Works Committee Subcommittee on Clean Air and Nuclear Safety, June 30, 2011 Oversight Hearing: Review of EPA Regulations Replacing the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule," https://www.epw.senate.gov/public/_cache/files/e/f/ef424b3a-c948-496d-9438-30674d9e25b3/01AFD79733D77F24A71FEF9DAFCCB056.tierneytestimonycombined.pdf.

with regulatory requirements, that together ensure that reliable electricity supply is a priority.

By 2011, it is not reasonable to suggest that EPA's CATR and Utility Toxics Rule are a surprise, or that EPA's proposed regulations will require actions that are technically and economically infeasible. These regulations have been in the works for many years. EPA's proposals allow more flexibility in compliance approaches than previously anticipated.

Many factors besides these new regulations have encouraged owners of coal-fired power plants to take steps to reduce their air emissions. Many states have already adopted regulations as strict as those proposed by EPA. Some companies with facilities affected by the CATR and Utility Toxics rules are already under court orders to achieve similar outcomes even without the new regulations. And many companies have already taken steps to install appropriate control equipment: in recent months, chief executive officers of some of the most affected utility companies in different parts of the country have told their investors that they are already or will be ready to meet the new EPA air regulations. These facts occur within a context in which low natural gas prices are putting pressure on many of the oldest, least-efficient and uncontrolled coal plants to retire for economic reasons.

Much attention has been, and will continue to be, paid to the impacts of the regulations on electric system reliability. Many assessments published in the past year have called attention to potential gaps that could arise in the absence of market, utility and regulators' responses. These studies highlight potential plant retirements under different sets of assumptions, with the more reasonable estimates indicating strongly that the impacts are manageable, as long as industry and its regulators respond in a timely fashion.

The industry has various tools to assure that reliability will not be adversely affected. Among the more important tools are: the strong system-planning processes of utility transmission companies and regional transmission organizations (grid operators); the opportunities for companies to obtain power resources through the wholesale power markets that exist in many of the affected parts of the country; the strong least-cost planning processes that exist for utilities in other affected areas; the interest and ability of developers of new power projects to bring new supplies to the market; the fact that state and federal [regulators] have a strong track record of taking the steps necessary to ensure that the companies they supervise are meeting their obligation to provide reliable electric service; the large reservoirs of untapped cost-effective energy efficiency in affected states that can be mined relatively rapidly and can help ease impacts on consumers' electricity bills; and the statutory tools available to EPA, the Federal Energy Regulatory Commission ("FERC"), the U.S. Department of Energy ("DOE"), and the President to take actions to ensure reliable system conditions when all else fails.

> Finally, recent market developments provide practical, real-world evidence that the EPA clean air regulations are manageable. Notably, the nation's largest competitive wholesale power market – PJM, serving much of the mid-Atlantic and Midwest regions affected by the EPA regulations – has recently conducted its annual auction to purchase capacity so that it will be available far in advance of need. The PJM auction elicited far more capacity offers from existing and new suppliers than is needed for reliability purposes during the period when EPA's new air rules will go into effect."

- During the mid-2010s, EPA was considering approaches to limit GHG emissions and in June 2014 proposed the Clean Power Plan, regulating carbon pollution from existing electric utility fossil generating units. There were myriad concerns raised about the direct impact of such regulations on potential retirements of fossil generating units (especially coal-fired power plants) and apparent consequential reliability concerns for the nation's electric system.

  The North American Electric Reliability Corporation ("NERC"), which is the nation's federally approved Electric Reliability Organization, had previously prepared assessments of the potential impacts of other future environmental regulations (including a November 2011 report on "Potential Impacts of Future Environmental Regulations: Extracted from the 2011 Long-Term Reliability Assessment)".[36] In November 2014, NERC issued its report on "Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review."[37] These NERC reports identified retirements of fossil generating units as a major concern, noting the EPA's proposed Clean Power Plan "aims to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030" and would lead to a major reduction in total generating capacity. NERC expressed its concern that, among other things, "[d]eveloping suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation" and that "Essential Reliability Services may be strained by the proposed CPP."

  During that period, I wrote several papers[38] on reliability considerations related to potential EPA regulation of GHG emissions. Among my observations and conclusions in those reports, I note the following here because they are relevant for consideration of the May 2023 EPA proposal to regulate GHG emissions from fossil generating units:

---

[36] This report examined implications of several EPA regulatory activities, including the proposed Coal Combustion Residuals rule, the MATS rule, the Cooling Water Intake Structures rule, and the Cross-State Air Pollution Rule. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/EPA%20Section.pdf.

[37] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf.

[38] Additionally, I testified before Congress on market and reliability considerations associated with EPA's regulation of GHG emissions from fossil fueled power plants: Testimony of Susan F. Tierney, Ph.D. Before the U.S. House of Representatives Committee on Energy and Commerce, Subcommittee on Energy and Power, "Hearing on EPA's Proposed GHG Standards for New Power Plants and H.R. _, Whitfield-Manchin Legislation November 14, 2013," https://docs.house.gov/meetings/IF/IF03/20131114/101482/HHRG-113-IF03-Wstate-TierneyS-20131114.pdf.

- In 2014, I wrote a white paper on EPA regulation of GHG emissions, with a focus on implications for electric system reliability.

    Historically, the reliability red flag has tended to be raised with regard to concerns that compliance with a new environmental rule would require a large portion of generating capacity to be simultaneously out of service to add control equipment, to retire permanently, or otherwise to become unavailable to produce power. To date, implementation of new environmental rules has not produced reliability problems, in large part because the industry has proven itself capable of responding effectively. A very mission-oriented industry, composed of electric utilities, other grid operators, non-utility energy companies, federal and state regulators, and others, has taken a wide variety of steps to ensure reliability."[39]

    Other factors also allow for cost-effective emissions reductions at Section 111(d) units in ways that do not adversely affect system reliability. A significant amount of existing generating capacity is underutilized. For example, output at natural-gas fired combined-cycle power plants averaged approximately 50 percent in 2012. There is the potential to reduce overall demand through energy efficiency, thus reducing the need to dispatch plants with relatively high emission rates. There is potential to add additional low or zero-carbon electricity supply (e.g., wind and solar; combined heat and power; nuclear uprates). Actions also can be taken to extend the life of, or increase the output from, well-performing generating units that produce no emissions at the facility (e.g., hydroelectric resources, nuclear plants).[40]

- In 2015, I participated in a FERC Technical Conference on reliability considerations relating to EPA's proposed Clean Power Plan, and then co-authored a report[41] that summarized and responded to a range of themes raised by other commenters at the series of Technical Conferences hosted by FERC in February and March 2015. Our report observed the following:

    Throughout the FERC CPP Technical Conferences, some participants questioned whether, in light of CPP-driven changes in the resource mix, the grid could continue to perform, especially through high energy demand periods or during unexpected events. These participants generally cited three main factors for these concerns: (1) closure of coal-fired power plants that provide energy, capacity, and

[39] Susan Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability," May 2014, https://www.analysisgroup.com/globalassets/content/insights/publishing/tierney_report_electric_reliability_and_ghg_emissions2.pdf.

[40] Susan Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability," May 2014, https://www.analysisgroup.com/globalassets/content/insights/publishing/tierney_report_electric_reliability_and_ghg_emissions2.pdf.

[41] Susan Tierney, Eric Svenson, and Brian Parsons, "Ensuring Electric Grid Reliability Under the Clean Power Plan: Addressing Key Themes from the FERC Technical Conferences," April 2015, https://blogs.edf.org/climate411/wp-content/blogs.dir/7/files/2015/04/Ensuring-Electric-Grid-Reliability-Under-the-Clean-Power-Plan.pdf.

> essential reliability services such as reactive power, inertia, and voltage control; (2) inadequate infrastructure to support increased demand for natural gas for power generation in various parts of the country, and/or inadequate natural gas supplies; and (3) higher reliance on renewable and demand-side resources.
>
> The evidence does not support the argument that the proposed CPP will result in a general and unavoidable decline in reliability. While we do expect significant changes to the overall mix of resources under the CPP, we believe resource planners and markets will have sufficient time and resources to respond to a realistic projection of system redispatch and facility retirements. Both FERC-jurisdictional electricity markets and state-regulated resource planning processes have provided and will continue to provide timely planning, operational, and financial signals for new resources that can help maintain reliability. With clear and transparent signals, market participants can respond in different time frames and investment cycles for different types of resources, including but not limited to new gas resources, end-use energy efficiency measures and demand response, renewables, electric transmission, and natural gas pipeline infrastructure. We note that several market participants filed comments with EPA indicating their readiness to step up with solutions to these challenges.[42]

- In 2015, I co-authored several reports that addressed electric reliability issues related to the EPA's Clean Power Plan. The initial report focused on tools and practices available to electric industry and its regulators to ensure reliable electric service even as the federal government begins to regulate GHG emissions from power plants.[43] The other reports examined more specific reliability considerations in two regions – the PJM region and the MISO region – with significant existing coal-fired and other fossil generating capacity that would be affected by the CPP.[44]

> Since the U.S. Environmental Protection Agency (EPA) proposed its Clean Power Plan last June, many observers have raised concerns that its implementation might jeopardize electric system reliability. Such warnings are common whenever there is major change in the industry, and play an important role in focusing the

[42] Susan Tierney, Eric Svenson, and Brian Parsons, "Ensuring Electric Grid Reliability Under the Clean Power Plan: Addressing Key Themes from the FERC Technical Conferences," April 2015, https://blogs.edf.org/climate411/wp-content/blogs.dir/7/files/2015/04/Ensuring-Electric-Grid-Reliability-Under-the-Clean-Power-Plan.pdf.

[43] Susan Tierney, Paul Hibbard and Craig Aubuchon, "Electric System Reliability and the EPA's Clean Power Plan: Tools and Practices," February 2015 (hereafter "Tierney et al Electric Reliability Tools and Practices" and attached to this report as Attachment 1) https://hepg.hks.harvard.edu/sites/hwpi.harvard.edu/files/hepg/files/electric_system_reliability_and_epas_clean_power_plan_0215.pdf?m=1529956845.

[44] Susan Tierney, Paul Hibbard and Craig Aubuchon, "Electric System Reliability and the EPA's Clean Power Plan: The Case of PJM," March 16, 2015, https://www.analysisgroup.com/globalassets/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_case_of_pjm2.pdf; and Susan Tierney, Paul Hibbard and Craig Aubuchon, "Electric System Reliability and the EPA's Clean Power Plan: The Case of MISO," June 8, 2015, https://www.analysisgroup.com/globalassets/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf.

> attention of the industry on taking the steps necessary to ensure reliable electric service to Americans. There are, however, many reasons why carbon pollution at existing power plants can be controlled without adversely affecting electric system reliability.
>
> Given the significant shifts already underway in the electric system, the industry would need to adjust its operational and planning practices to accommodate changes even if EPA had not proposed the Clean Power Plan. In the past several years, dramatic increases in domestic energy production (stemming from the shale gas revolution), shifts in fossil fuel prices, retirements of aged infrastructure, implementation of numerous pollution-control measures, and strong growth in energy efficiency and distributed energy resources, have driven important changes in the power sector. As always, grid operators and utilities are already looking at what adjustments to long-standing planning and operational practices may be needed to stay abreast of, understand, and adapt to such changes in the industry.
>
> The standard reliability practices that the industry and its regulators have used for decades are a strong foundation from which any reliability concerns about the Clean Power Plan will be addressed. The electric industry's many players are keenly organized and strongly oriented toward safe and reliable operations. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations of the system, day in and day out…..
>
> Some of the reliability concerns raised by stakeholders about the Clean Power Plan presume inflexible implementation, are based on worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. There is no historical basis for these assumptions. Reliability issues will be solved by the dynamic interplay of actions by regulators, entities responsible for reliability, and market participants with many solutions proceeding in parallel. Some of the cautionary comments are just that: calls for timely action…
>
> In the end, because there are such fundamental shifts already underway in the electric industry, inaction is the real threat to good reliability planning. Again, there are continuously evolving ways to address electric reliability that build off of strong standard operating procedures in the industry.

In the end, there were no reliability problems that arose as a result of EPA's proposed and/or adopted regulation of air emissions from fossil-fueled power plants. This outcome occurred even as other EPA air-pollution rules (e.g., mercury controls, air transport regulations) did go into effect.

In fact, as noted previously, even though the EPA's Clean Power Plan was eventually stayed by federal courts and repealed and replaced by the EPA in 2019,[45] the CPP goal of reducing CO2 emissions from power plants by 32 percent by 2030 was reached by 2020, a decade earlier than planned by the CPP.[46] By that point, transitions in the electric industry (including retirements of significant and relatively inefficient fossil generating capacity, a shift from coal-fired generation to gas-fired power production, and the addition of significant new wind and solar capacity) had taken place more quickly than had been anticipated when the CPP was under consideration.[47]

In many ways, today's context for considering reliability issues related to EPA's new proposal to regulate power plant GHG emissions differs in a number of ways, in other regards the reliability issues, including tools and practices for ensuring reliability, are not so different than they were in the past decade, as described in the following sections of this report.

---

[45] https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-repealing-clean-power-plan#:~:text=Additional%20Resources-,Rule%20Summary,the%20Affordable%20Clean%20Energy%20rule.

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

[47] *See*, for example, EIA, "Analysis of the Impacts of the Clean Power Plan," May 22, 2015, https://www.eia.gov/analysis/requests/powerplants/cleanplan/.

V. Concerns Raised About EPA's 2023 Proposal: Thematic and Technical Issues

A. Overview: Changing conditions in the nation's electric industry

EPA's Preamble describes the changing conditions in the U.S. electric industry, with observations that rely on and cite to many scholarly and expert analyses. As summarized in the Preamble, these power sector changes and trends include: "a prolonged period of transition and structural change. Since the generation of electricity from coal-fired power plants peaked nearly two decades ago, the power sector has changed at a rapid pace. Today, natural gas-fired power plants provide the largest share of net generation, coal-fired power plants provide a significantly smaller share than in the recent past, renewable energy provides a steadily increasing share, and as new technologies enter the marketplace, power producers continue to replace aging assets with more efficient and lower cost alternatives."[48] EPA notes that many owners of existing coal-fired power plants have either already retired them in recent years due to their no longer being economic to operate and maintain, or have announced their intention to retire specific generating units in the future.[49]

The electric-sector trends observed by EPA in detail in the Preamble are consistent with those described in detail in recent National Academies' consensus studies of which I was a co-author: *The Future of Electric Power in the U.S.* (2021),[50] *Accelerating Decarbonization in the U.S* (2021, 2023),[51] and the *Role of Net Metering in the Evolving Energy System* (2023).[52] These trends are also the subject of numerous other governmental, expert and stakeholder groups, including ones related to gas/electric coordination issues,[53] cybersecurity risks,[54] transitions in

[48] Preamble, at 33255, and 33256-33266 and 33415-33416 more generally.

[49] EPA stated that: "Industry stakeholders have requested that the EPA structure this rule to avoid imposing costly control obligations on coal-fired power plants that have announced plans to voluntarily cease operations, and the EPA proposes to accommodate those requests." Preamble, at 33255.

[50] NASEM Future of Electric Power.

[51]; NASEM 2021 Decarbonization Study; NASEM 2023 Decarbonization Study.

[52] National Academies of Sciences, Engineering and Medicine, "The Role of Net Metering in the Evolving Electricity System" (2023) (hereafter "NASEM Net Metering Study"), https://www.nationalacademies.org/our-work/the-role-of-net-metering-in-the-evolving-electricity-system.

[53] FERC, NERC, and Regional Entity Joint Staff Inquiry, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations," September 21, 2023, https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott; FERC, NERC, and Regional Entity Joint Staff Inquiry, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations," September 21, 2023, https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[54] NASEM, Future of Electric Power.

generation portfolios,[55] need to enhance the resilience of energy infrastructure,[56] and transmission expansion challenges.[57]

The Preamble and the Technical Support Document also acknowledge the important influences and roles of other actions and developments – like the increasingly apparent impacts of a changing climate, changes in electricity demand and consumer preferences, the enactment of the 2021 Infrastructure Investment and Jobs Act and the 2022 Inflation Reduction Act, other changes in the cost and performance of electricity generation technologies and fossil fuels, trends in states' adoption of policies affecting the power sector's reliance on different resource portfolios and its emissions of GHGs, and increasing numbers of power companies with commitments to reduce GHG emissions.[58]

Perhaps with the exception of the two new federal statutes[59] which in 2021 and 2022 established extraordinary new levels of financial support and bolstered federal authority for various public and private investment in clean energy technology, these electric-industry changes have been underway for much of the past decade. As such, many of the discussions of reliability concerns and strategies described in the prior section of this report are entirely relevant today.

That said, there are heightened concerns in recent years, in part due to some recent reliability events (e.g., Winter Storm Uri in 2021 and Winter Storm Elliott in 2022[60]) that stressed electric and other energy infrastructure and in some cases produced blackouts or near blackouts with fatal consequences.[61] There is substantial attention to bulk power system reliability being paid by numerous entities, including by NERC which is capably exercising its

---

[55] NASEM, Future of Electric Power; National Academies of Sciences, Engineering and Medicine, "Accelerating Decarbonization of the U.S. Energy System" (2021) (hereafter "NASEM 2021 Decarbonization Study") and "Accelerating Decarbonization in the United States: Technology, Policy and Societal Dimensions" (2023) (hereafter "NASEM 2023 Decarbonization Study"), https://www.nationalacademies.org/our-work/accelerating-decarbonization-in-the-united-states-technology-policy-and-societal-dimensions.

[56] *See* for example: U.S. Department of Energy ("DOE"), "National Transmission Needs Study," October 2023, https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf; DOE, "Biden-Harris Administration Announces $13 Billion to Modernize and Expand America's Power Grid," November 18, 2022, https://www.energy.gov/articles/biden-harris-administration-announces-13-billion-modernize-and-expand-americas-power-grid.

[57] *See* for example: Joint Federal-State Task Force on Electric Transmission, https://www.ferc.gov/media/e-1-ad21-15-000; DOE, "Biden-Harris Administration Announces $3.5 Billion for Largest Ever Investment in America's Electric Grid, Deploying More Clean Energy, Lowering Costs, and Creating Union Jobs," October 18, 2023, https://www.energy.gov/articles/biden-harris-administration-announces-35-billion-largest-ever-investment-americas-electric.

[58] Preamble, at 33249-33266.

[59] The Inflation Reduction Act has been called the first and largest climate policy law enacted by Congress. *See* for example: Emma Newburger, "The U.S. passed a historic climate deal this year – here's a recap of what's in the bill," CNBC, December 30, 2022, https://www.cnbc.com/2022/12/30/2022-climate-recap-whats-in-the-historic-inflation-reduction-act.html; Josh Bivens, "The Inflation Reduction Act finally gave the U.S. a real climate change policy," August 14, 2023, https://www.epi.org/blog/the-inflation-reduction-act-finally-gave-the-u-s-a-real-climate-change-policy/.

[60] FERC – NERC – Regional Entity Staff Report, "The February 2021 Cold Weather Outages in Texas and the South Central United States," November 2021, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and; FERC, NERC, and Regional Entity Joint Staff Inquiry, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations," September 21, 2023, https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[61] Budget Committee 2023. Tierney Budget Committee Testimony 2023; Testimony of Dr. Melissa Lott of the Columbia University Center on Global Energy Policy before the Senate Committee on Energy and Natural Resources, Hearing on Electric Reliability, June 1, 2023, https://www.energypolicy.columbia.edu/wp-content/uploads/2023/05/Lott-SENR-Testimony-with-appendix-v20230530-1.pdf.

essential role of calling attention to issues related to the adequacy, security and resilience of the power system.

For example, the most recent NERC Long-Term Reliability Assessment (December 2022)[62] identifies "government policies, regulations, consumer factors, and economic factors" as helping to shape transitions in the bulk power system. Prolonged, extreme weather events[63] and "continuing resource mix challenges"[64] are also creating new reliability challenges in recent and in upcoming years. In short: "Energy systems and the electricity grid are undergoing unprecedented change" with the need for relevant actors to take steps to ensure reliability. Such steps include "effective regional transmission and integrated resource planning processes," the adoption of policies and market mechanisms to ensure the capability of the system to maintain "essential reliability services,"[65] transmission investment,[66] "managing the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services,"[67] and mitigating "the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure."[68]

---

[62] NERC, "Long-Term Reliability Assessment," December 2022 (hereafter "NERC Long-Term Reliability Assessment 2022"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

[63] "Electricity supplies can decline in extreme weather for many reasons. Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts. Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers. Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electric generation. Wind, solar, and other variable energy resource (VER) generators are dependent on the weather." NERC Long Term Reliability Assessment 2022.

[64] Several such challenges are called out by NERC, including: "reliable interconnection of inverter-based resources," "accommodating large amounts of distributed energy resources," "managing the pace of generation retirements," "maintaining Essential Reliability Services" (e.g., "capability to support voltage, frequency, and dispatchability," as well as reactive support, stability, and ramping/balancing). NERC Long-Term Reliability Assessment 2022.

[65] NERC states that "[v]arious technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue." NERC Long-Term Reliability Assessment 2022.

[66] "There has been some increase in the number of miles of transmission line projects for integrating renewable generation over the next 10 years compared to the 2021 LTRA projections. Transmission investment is important for reliability and resilience as well as the integration of new generation resources." NERC Long-Term Reliability Assessment 2022.

[67] "State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks. • Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators. • Resource planners and policymakers must pay careful attention to the pace of change in the resource mix as well as update capacity and energy risk studies (including all-hours probabilistic analysis) with accurate resource projections." NERC Long-Term Reliability Assessment 2022.

[68] "Addressing the Reliability Needs of Interdependent Electricity and Natural Gas Infrastructures. Natural gas is an essential fuel for electricity generation that bridges the reliability needs of the BPS [Bulk Power System] during this period of energy transition. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. Energy stakeholders must urgently act to solve reliability challenges that arise from interdependent natural gas and electricity infrastructure" including through promoting coordination of these two systems." NERC Long-Term Reliability Assessment 2022.

More recently, NERC published an update report on priority risks that need to be addressed, with identification of "strategic directions" the industry should take to understand, plan for and mitigate such risks.[69] The report highlights "five significant evolving risk profiles":

> **Energy Policy** at the federal, province, state, provincial and local levels is providing incentives and targets for resource changes and end-use applications of electricity. It is further contributing to the **Grid Transformation**, which includes the shift away from conventional synchronous central-station generators toward a new mix of resources that include natural-gas-fired generation; unprecedented proportions of non-synchronous resources, including renewables and energy storage; demand response; smart- and micro-grids; and other emerging technologies which will be more dependent on communications and advanced coordinated controls that can increase the potential **Security Risks**. Collectively, the new resource mix can be more susceptible to long-term, widespread **Extreme Events,** such as extreme temperatures or sustained loss of wind/solar, that can impact the ability to provide sufficient energy as the fuel supply is less certain. Furthermore, there is an associated increase in **Critical Infrastructure Interdependencies**. For example, for natural-gas-fired generation, there is increased interdependency on delivery of fuel from the natural gas industry that also depends on electricity to support its ability to extract and transport gas.

Although NERC does not specifically call out the risks relating to the design or implementation of EPA regulation of GHG emissions from power plants, the report includes decarbonization policy as part of the "energy policy" drivers of changes in demand and supply of electricity and other aspects of grid transformation. NERC's priority reliability risks report includes numerous recommendations to mitigate risks related to energy policy[70] (which NERC describes as including a wide range of federal, state and local policies relating to electrification of buildings and vehicles, other decarbonization policies, as well as adoption of central-station and decentralized renewable, low- and no-carbon resources, and other supply resources).

The NERC reliability risks report also includes recommendations in five other priority areas, which collectively address the complex planning, operational and other challenges that the industry must address to maintain system

---

[69] NERC, "2023 ERO Reliability Risk Priorities Report" (RISC Approved 7-24-2023; NERC Board approved 8-17-2023) (hereafter "NERC Reliability Risk Priorities Report 2023"), https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf. ("ERO" refers to Electric Reliability Organization.)

[70] "Increased coordination and collaboration between federal, provincial, and state policy makers, regulators, owners, and operators of the BPS as well as with the critical interdependent sectors is needed. Communication, coordination, and collaboration should be early, consistent, and clear to bridge increasingly complex jurisdictional lines. Education for policymakers and regulators to increase awareness of the reliability implications of policy decisions is a critical need. In addition, education for the industry, as the developers of reliability standards, is needed to better understand the processes and implications of policy decisions. Power system reliability requires many actively engaged, closely coordinated partners. NERC and state commissions share common goals in ensuring a reliable, resilient, safe, affordable electricity system that serves all customers. States, and the utilities they regulate, are responsible for the distribution systems, including DERs [distributed energy resources], and with some utilities responsible for resource acquisition and adequacy. As economic regulators, state commissions review and approve utility investment proposals which have long term impacts on power system reliability. State perspectives are important to NERC's success – translating BPS considerations to state-level needs, experience, and policy objectives. Concurrently, NERC's perspectives are important to the States' success..." NERC Reliability Risk Priorities Report 2023.

reliability. (I have included the full list of NERC recommendations in footnotes here to illustrate the number of actions that NERC recommends be taken in upcoming years, regardless of whether federal regulators put in place new requirements to regulate GHG emissions from fossil fuel power plants.) These other four areas are: grid transformation,[71] physical and cyber security,[72] extreme events,[73] and critical infrastructure interdependencies.[74]

---

[71] "Grid transformation will continue to require new and innovative approaches, tools, methods, and strategies to be used in planning and operating the BPS. To address these challenges and opportunities, [NERC] encourages the following actions in order of evaluated criticality to have the most impact and likelihood of mitigating the risk: 1. Develop and include energy sufficiency approaches in planning and operating the grid….NERC and the industry should collaborate to better understand and define energy sufficiency and develop approaches that examine the magnitude, duration, and impact across all hours and many years while also considering limitations and contributions to reliability from all resources (including load resources), neighboring grids, and transmission….2. Ensure sufficient operating flexibility during resource and grid transformation….3. Further consider the impacts and benefits of DER resources, electrification, energy storage, hybrid resources, and other emerging technologies….4. Plan for large and rapid load growth….5. Expand marketing to and development of the workforce of the future….6. Expect and be open to dramatically new grid operation approaches and platforms." NERC Reliability Risk Priorities Report 2023.

[72] "1. NERC should develop guidance for industry on the best practices to mitigate the risks from cloud adoption and the use of AI technologies. 2. NERC should continue to facilitate the development of planning approaches, models, and simulation methods that may reduce the number of critical facilities and thus mitigate the impact relative to the exposure to attack. 3. The ERO should take the lead in encouraging government partners to create a supply chain certification system….4. NERC should develop guidance to define best practices for "Secure by Design" and "Adaptive Security" principles in information technology and operational technology systems development and implementation. 5. The Electricity Information Sharing Analysis Center (E-ISAC) should continue to encourage industry efforts on workforce cyber education… 6. NERC should highlight [and provide training on] key risk areas that arise from the EPRI's EMP [electromagnetic pulse] analysis for timely industry action….7. NERC, while collaborating with industry, should continue to evaluate the need for additional assessments of the risks from attack scenarios (e.g., vulnerabilities related to drone activity, attacks on midstream or interstate natural gas pipelines or other critical infrastructure)….8. E-ISAC should continue to execute its long-term strategy to improve cyber and physical security information-sharing, protection, risk analysis, and increase engagement within the electric sector as well as potential foreign adversaries should continue to be addressed by the E-ISAC, other federal partners, and industry to continue diligently working to mitigate threats. 10. The industry must continue to focus on early detection and response to cyber attacks and adopt controls that can be executed to protect critical systems. 11.….NERC should continue to expand the scope of GridEx [exercises] to include and collaborate with cross-sector industries, such as natural gas, telecom, and water as well as state, local, and tribal authorities….12. [Other efforts relating to cybersecurity risk Information sharing should continue]." NERC Reliability Risk Priorities Report 2023.

[73] "1. Conduct special assessments of extreme event impacts, including capturing lessons learned, create simulation models, and establish protocols and procedures for system recovery and resiliency… 2. Accelerate planning and construction of strategic, resilient transmission. …. For instance, prioritize transmission installation with the explicit objective of reducing resilience risk and ensuring "hardening" for anticipated risks….3. Development of tools for BPS resiliency: DOE is performing analyses to evaluate both static, dynamic, and real-time scenarios that affect BPS reliability and resilience including transmission needs and planning studies, and evaluation of asset performance under extremes. NERC should continue to work with DOE on these efforts to ensure robust tools that can be used industry wide to evaluate potential threats to generation, transmission, and fuel supplies. 4. Regional coordination: States and any other applicable governmental authorities should meet collectively to discuss and understand impacts to ensure they are a part of the resiliency discussion….5. Workforce development: Entities should continue to focus on attracting, developing, and retaining the skilled workforce needed to plan, construct, and operate the transforming [grid]. 6. Industry forums: Forums should share and coordinate information sharing on best practices around resiliency efforts related to design considerations, supply chain deliverability issues, and identification and response to major storm events….7. Drills and emergency response: BPS operators should have formal emergency management programs that include periodic drills and exercises…8. Understanding of geomagnetic disturbance events on BPS." NERC Reliability Risk Priorities Report 2023.

[74] "1. NERC should conduct a study to determine the percent of available generation with on-site or firm fuel capacity in each Regional Entity….NERC and industry partners should continue to conduct meetings and conferences to highlight the importance of cross-sector and energy subsector interdependence and coordination, such as the NERC Reliability Summit, NATF/EPRI resiliency summits, the North American Energy Standards Board Forum, and FERC/DOE technical conferences….NERC, in collaboration with industry and industry partners, should continue to identify and prioritize limiting conditions and/or contingencies that arise from other sectors that affect the BPS. NERC and Reliability Coordinators should continue to conduct special assessments that address natural gas availability and pipeline common mode failures. NERC and industry partners should continue to increase emphasis on cross-sector coordination in industry drills ….NERC should investigate the feasibility of potential infrastructure improvements, such as feeder segmentation required to facilitate more pinpoint control of load during emergencies in order to increase the amount of load available for rotating outages. The EPRI and DOE should continue their work on communication alternatives but also the use of same or similar technologies for critical supervisory control and data acquisition data. New technologies should be explored that could assist in providing unique and hardened back-up telecommunication methods for the most critical data. The ERO Enterprise should continue to communicate to state, provincial,

These recommendations encompass a wide variety of actors in industry and government, and touch on specific areas of needed analysis, information sharing and coordination over time as conditions continue to change.

There are other discussions – e.g., in Texas, at FERC-regulated Regional Transmission Organizations ("RTOs"), and at the North American Energy Reliability Board ("NAESB")[75] – to address problems and concerns relating to preparedness and performance of electric facilities and in gas production and delivery, particularly in extreme weather situations. FERC/NERC's reports, for example, concluded that all types of generating technologies failed to adequately prepare for extreme cold weather or freezing conditions, with gas-fired units experiencing significant incremental unplanned outages, in part due to gas production, supply and delivery issues constituting the second-largest cause of unplanned outages after mechanical issues relating to cold and freezing conditions.[76] FERC/NERC's recommendations reflect the lessons learned from past events, including FERC/NERC's specific recommendations to identify critical facility components and systems that need freeze-protection measures and to prepare and execute plans to address such winterization.[77]

I note that many of these recommendations are similar – and in some cases, identical – to recommendations in reports, forums, and studies with which I have been personally involved and which focused on critical actions needed to address the complex changes already underway in the nation's electric system. For example, the National Academies' Future of Electric Power in the U.S. study identified five "major needs" for the future electric power system, including the following (and also made recommendations related to each one): (1) improving our understanding of how the system is evolving; (2) ensuring that electricity service remains clean and sustainable, and reliable and resilient; (3) improving understanding of how people use electricity and keep electricity affordable and equitable in the face of profound change; (4) facilitating innovation in technology, policy and business models relevant to the power system; and (5) accelerating innovation in technology in the face of shifting global supply chains and the influx of disruptive technologies.[78] The National Academies' Net Metering Study describes the local reliability systems that need greater visibility, operational controls and other mechanisms to be ready for increasing deployment of distributed energy resources with new power flows on the grid.[79]

Many of these broader concerns show up in comments and concerns raised in the context of EPA's proposed regulation of existing and new fossil generating units, even though EPA's proposal did not create these issues.

---

and federal regulators of natural gas about the critical interdependence of this fuel source with the other infrastructure sectors. NERC and industry partners should continue to evaluate voice and data communication interdependencies and strategies for ensuring continuous communications during an emergency event, particularly as remote working arrangements grow. NERC should continue to encourage industry to consider the unavailability of other critical infrastructures, such as water, sewer, roads, rails, and communications in their emergency plans." NERC Reliability Risk Priorities Report 2023.

[75] North American Energy Standards Board, "Gas Electric Harmonization Forum Report," July 28, 2023, https://naesb.org/pdf4/geh_final_report_072823.pdf. I served as a co-chair of this Forum and co-authored the Foreword with my two co-chairs, Robert Gee and Pat Wood, III.

[76] See, for example, Section IV of the February 2021 Cold Weather Outages staff report by FERC/NERC/Regional Entities. https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[77] See, for example, Section IV of the February 2021 Cold Weather Outages staff report by FERC/NERC/Regional Entities. https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[78] NASEM Future of Electric Power Study.

[79] NASEM Net Metering Study, especially chapters 2, 6, and 7.

B. Reliability-related themes in comments on EPA's 2023 proposal

Several themes emerge from comments on reliability implications of EPA's proposed power plant GHG rule. These concerns include: the already-challenging operational conditions in the electric system; challenges relating to the ability of the industry to expand the transmission system; and the role of the proposal in leading to premature fossil unit retirements.

First, regarding challenging operational conditions on the electric system as a result of potential increases in demand and changes in the supply portfolio: Whether or not EPA moves forward with its proposed rule, such conditions are present and will continue to grow as operational changes and challenges, as discussed in the prior section. NERC's recommendations in its 2023 priority reliability risks report detail a broad and deep array of actions that should and can be taken to address these issues (including the impacts of any incremental changes introduced by promulgation of EPA's rule). As noted in NERC's report, these efforts are important to undertake now.

Additionally, the long list of specific recommendations that my colleagues and I previously identified as important tools and practices for assuring reliability in the context of EPA's adoption of prior regulations of GHG emissions from power plants still remain relevant here.[80] That report identified the array of key players with responsibilities that relate directly or indirectly to electric-system reliability – including FERC, other federal agencies, NERC, regional reliability organizations, system operators and balancing authorities, states, vertically integrated utilities, other power plant owners, energy efficiency program operators, and others – and potential actions that they can consider taking in the context of new EPA GHG regulations.

If the EPA's proposed rule is finalized in 2024 as anticipated by EPA, the industry will have nearly a decade to address any incremental reliability issues introduced by the rule and shaped by states' SIPs over the subsequent two years (and where the states can hear input from industry stakeholders about how to introduce greater flexibility into their plans).

Most of the nation's power plant capacity is not covered by these regulations, and includes nuclear facilities,[81] central station and distributed renewable facilities,[82] and existing combustion turbine units that are smaller than 300 MW or that operate infrequently (i.e., less that 50percent capacity factor). Notably, most existing gas-fired combustion turbines (operating as stand-alone peaking units or in combined cycle configurations) are smaller than 300 MW and therefore not covered by the proposal. According to the Energy Information Administration's current inventory of power plants, a significant share of such capacity (and associated generating units) is in this "less than 300 MW in size" category, as shown in Table 2:

[80] See recommendation Tables 1-6 in Tierney et al. Reliability Tools and Practices (Attachment 1 to this report). https://hepg.hks.harvard.edu/sites/hwpi.harvard.edu/files/hepg/files/electric_system_reliability_and_epas_clean_power_plan_0215.pdf?m=1529956845.

[81] Nuclear generating capacity amounts to 100.5 GW. EIA Monthly Generator Inventory (existing generating units with 1 MW or greater capacity (nameplate)), August 2023 (hereafter "EIA Generator Inventory"), https://www.eia.gov/electricity/data/eia860M/.

[82] Capacity of hydro, wind, solar, and geothermal generating facilities greater than 1 MW amounts to 311 GW. EIA Generator Inventory.

Table 2: Existing Gas-Fired Combustion Turbines (Simple Cycle and Combined Cycle)

Gas-Fired CTs	Total In Operation		Total In Operation And <300 MW in Size		Total In Operation and >300 MW in Size	
	# of units	GW total	# of units	GW total	# of units	GW total
CTs (simple cycle CTs)	1,755	141 GW	1,753	140.3 GW	2	0.7 GW
CCs (combined cycle CTs)	1,540	291 GW	1,359	219.0 GW	181	72.0 GW
**All Gas-Fired CTs	3,295	432 GW	3,112	359.3 GW	183	72.7 GW
Percentage of Currently Operating Gas-Fired CTs affected by EPA proposal			94% not covered	83% not covered	6% covered	17% covered

Source:
EIA Monthly Generator Inventory (existing generating units with 1 MW or greater capacity (nameplate)), August 2023, https://www.eia.gov/electricity/data/eia860M/.

An additional 43.7 GW of existing coal capacity[83] is currently scheduled to retire by 2032 (an amount equivalent to 24 percent of total coal-fired capacity) and needs only to perform routine O&M to comply with the EPA proposal. Also, 4.3 GW of coal-fired capacity has planned retirements in 2032 and 2033, thus similarly complying with EPA's proposal if their capacity factor is below 20 percent. This reflects another 2 percent of currently operating coal-fired steam unit capacity. Given that the EPA Section 111(d) rule is not finalized much less in effect, it is reasonable to assume that market forces and other public policies (and/or utility commitments) have led to such existing retirement announcements.

Note that current estimates of lead times for permitting and constructing new non-renewable capacity are: 24 months for battery storage; 36 months for gas-fired simple cycle CTs; and 48 months for gas-fired combined cycles.[84] Even a doubling of such time frames – such as to account quite conservatively for permitting delays or other extensions of lead times for individual projects – could allow for the economical and timely development of new facilities. Many projects are already in interconnection queues or in development, permitting, financing, and/or construction stages, and may be completed and interconnected in the years leading up to proposed implementation of the more stringent elements of EPA's proposals (e.g., post 2032). Before then, new gas-fired facilities entering service are only held to the use of efficient current CT and CC technologies. Of course, significant quantities of wind and renewable capacity are also in some stage of project development.

Second, regarding challenges in the nation's ability to expand the transmission system to support changes in the electric system: Certainly, the difficulties of adding transmission are well known and being addressed in many

[83] EIA's inventory indicates that 92 existing conventional coal units owned by utilities and independent power products and currently in operations have announced retirements by the end of 2031. EIA Generator Inventory.

[84] Paul Hibbard, Todd Schatzki, Charles Wu and Christopher Llop (Analysis Group) & Matthew Lind, Kiernan McInerney, and Stephanie Villarreal (Burns & McDonnell), "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report," September 9, 2020.

fora.[85] FERC has opened and received comments in a proposed rulemaking on transmission planning, cost allocation and interconnection, with final rules issued on generator interconnections in July 2022.[86]

The Infrastructure Investment and Jobs Act acknowledged such challenges in its provisions that provide expanded federal authorities to facilitate transmission expansion. The Congressional Research Service summarized these transmission-related activities as follows:

> Section 40105 of IIJA revises the process for designation of a National Interest Electric Transmission Corridor (NIETC) by the Department of Energy (DOE). A key revision allows for an NIETC designation that may lead to new interstate transmission lines specifically for intermittent (e.g., renewable) energy to connect to the electric grid. Another key change in the section enhances FERC's "backstop" siting authority for transmission lines in NIETCs. This would allow FERC to supersede traditional state permitting of transmission facilities and issue a permit for the construction and operation of certain interstate facilities under defined circumstances, including when a state has denied an applicant's request to site transmission facilities.
>
> Section 40106 establishes the ''Transmission Facilitation Program,'' under which DOE can facilitate the construction of electric power transmission lines and related facilities. Under this program, DOE may potentially enter a capacity contract (for no more than 40 years or 50 percent of the total capacity) with respect to an eligible transmission project; issue a loan to an eligible entity for an eligible transmission project; or participate with an eligible entity in designing, developing, constructing, operating, maintaining, or owning an eligible transmission project. Thus, under a capacity project, DOE could be closely involved in operational support of eligible transmission-line construction. Such an arrangement could help move a transmission project from proposal to construction, as a transmission project is unlikely to be built without significant customer commitment to its use. Section 40106 also establishes a "Transmission Facilitation Fund" to help finance eligible projects deemed to be in the public interest.

The Department of Energy has established a Grid Deployment office and has already made a number of significant commitments in support of new transmission. Recently announced actions include the agency's

---

[85] *See*, for example: NASEM Future of Electric Power study; NASEM Decarbonization study; Institute for Policy Integrity, "Transmission Siting Reforms in the Infrastructure and Jobs Act of 2021," December 2021, https://policyintegrity.org/files/publications/Building_a_New_Grid_Policy_Brief_v3_%281%29.pdf; Institute for Policy Integrity, Memo to DOE Grid Deployment Office on Coordination of Federal Authorizations for Electric Transmission Facilities, October 2, 2023, https://policyintegrity.org/documents/Comments_of_Institute_for_Policy_Integrity.pdf; Liza Reed et al., "How are we going to build all that clean energy infrastructure?", Niskanen Center, August, 2021, https://www.niskanencenter.org/wp-content/uploads/2021/08/CATF_Niskanen_CleanEnergyInfrastructure_Report.pdf; James Hewett, "Advancing U.S. Transmission Deployment: Navigating the Policy Landscape," Breakthrough Energy. August 7, 2023, https://breakthroughenergy.org/news/transmissiondeployment/.

[86] FERC, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," 179 FERC ¶ 61,028, No. RM21-17-000, April 21, 2022, https://www.ferc.gov/media/rm21-17-000; https://www.ferc.gov/electric-transmission/generator-interconnection.

.

commitment of $1.3 billion to help fund three major new transmission projects[87] and the publication of the National Transmission Needs Study.[88] Combined with the new authorities provided by Congress to DOE and FERC, and the current efforts of the DOE to use them, it is reasonable to assume that transmission bottlenecks and challenges are being addressed on a timeframe consistent with the compliance milestones anticipated by EPA in its proposed rule. Moreover, EPA's assessment of the impacts of the 2023 proposal are relatively conservative with regard to their assumptions about expansion of the interstate transmission system in support of development of renewable electricity projects.[89]

Notably, also, transmission expansion designed to support reliability outcomes tends to be approved more readily than projects aimed primarily at providing economic savings or to support public policy. To the extent that reliability challenges complicate fossil generating units' compliance strategies (e.g., including retirements, as discussed further below), there are numerous examples of successful siting approvals for such lines.[90]

Third, regarding premature retirements of fossil steam units (especially coal-fired generating units): The trends in retirements of coal-fired generation are driven principally by fundamental market economics.[91] EPA's rule allows for plants to stay in operation until the end of 2034 – a decade from now – if the unit maintains a capacity factor of no more than 20 percent (or for any level of output if a unit is retired by 2032). Already, there are dozens of coal-fired steam units with recent capacity factors below or around that levels.[92] And currently, plant owners have indicated retirement plans of approximately a quarter of total coal-fired steam capacity by those dates. Plants that commit to retire by the end of 2039 (fully 15 years from now) will need to co-fire with natural gas starting in 2030. The EPA has modeled estimated retirements of coal plants, but what will ultimately matter from a reliability point of view is the resource adequacy and other operating conditions on the grid at the time a plant is actually planning on retiring. These timelines are many years away.

To the extent that a unit has not yet announced retirement and operating conditions lead to an owner's decision to retire it (due to an uneconomic financial outlook for the facility) by any of those milestone dates, the unit's owner will need to get permission (from a reliability point of view) to retire the facility to determine whether taking the plant permanently out of service would trigger local or regional reliability issues. Most coal-fired generating capacity is either (a) owned by a vertically integrated utility with the ability to request cost recovery of a unit until alternative resources are in place to allow it to retire without adverse consequences to local reliability, or (b) not owned by a

---

[87] DOE, "DOE Launches New Initiative from President Biden's Bipartisan Infrastructure Law to Modernize National Grid," January 12, 2022, https://www.energy.gov/oe/articles/doe-launches-new-initiative-president-bidens-bipartisan-infrastructure-law-modernize; DOE, "Biden-Harris Administration Announces $1.3 Billion to Build Out Nation's Electric Transmission and Releases New Study Identifying Critical Grid Needs," October 30, 2023, https://www.energy.gov/articles/biden-harris-administration-announces-13-billion-build-out-nations-electric-transmission.

[88] DOE, "National Transmission Needs Study," October 2023, https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf.

[89] See comments of Clean Air Task Force and Natural Resources Defense Council, EPA Docket No. EPA-HQ-OAR-2023-0072, August 8, 2023, pages 45-51, https://cdn.catf.us/wp-content/uploads/2023/08/09090744/CATF-and-NRDC-Comments-on-Proposed-Rule-EPA-HQ-OAR-2023-0072-1.pdf?_gl=1*1ork94d*_ga*MjEyMzQ4MDA3LjE2OTU4NzY5MzA.*_ga_88025VJ2M0*MTY5ODQzOTUyMy40LjAuMTY5ODQzOTUyNC42MC4wLjA.*_gcl_au*MTIxNTk3MjA0Ni4xNjk1ODc2OTMw.

[90] NASEM, Future of Electric Power.

[91] NASEM Decarbonization: Chapters 6 (The Essential Role of Clean Electricity) and Chapter 12 (The Future of Fossil Fuels).

[92] SPGlobal Regional Power Summary, accessed 11-1-2023.

regulated utility but operates in an RTO region which can put in place reliability-must-run compensation arrangements to cover plant O&M costs to keep it in service until alternatives (including wires and non-wires alternatives) are in place, if needed for reliability.[93]

EPA's Resource Adequacy TSD refers to these and other options as mechanisms that help to ensure reliable system operations, which the agency has taken into account in the development of its proposal and accompanying implementation approach.

> The emission reduction requirements under this rule are based on adequately demonstrated cost-reasonable control measures that form the BSER. Some EGU owners may conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new emissions controls at the unit. However, the EPA also understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant regional transmission organization (RTO), balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. The Agency also expects that any resulting unit retirements will be carried out through an orderly process in which RTOs, balancing authorities, and state regulators use their powers to ensure that electric system reliability is protected.[94]

[93] Tierney et al Electric Reliability Tools and Practices; Paul Hibbard, Pavel Darling and Susan Tierney, "Potomac River Generating Station: Update on Reliability and Environmental Considerations," July 19, 2011, https://www.cleanskies.org/wp-content/uploads/2011/07/PRGSReportAnalysisGroup2011.pdf.

[94] EPA, Resource Adequacy Technical Support Document, https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0034.

More specifically, the EPA Preamble further describes the reliability options available within the proposed rule and existing in current policy, as excerpted in the text box here:

EPA Preamble
Section XIV.F: Grid Reliability Considerations (excerpts)

Preserving the ability of power companies and grid operators to maintain system reliability has been a paramount consideration in the development of these proposed actions.

Accordingly, these proposed rules include significant design elements that are intended to allow the power sector continued resource and operational flexibility, and to facilitate long-term planning during this dynamic period. Among other things, these elements include subcategories of new natural gas-fired combustion turbines that allow for the stringency of standards of performance to vary by capacity factor; subcategories for existing steam EGUs that are based on operating horizons and fuel reflecting the request of industry stakeholders; compliance deadlines for both new and existing EGUs that provide ample lead time to plan; and proposed State plan flexibilities.

In addition, this preamble discusses EPA's intention to exercise its enforcement discretion where needed to address any potential instances in which individual EGUs may need to temporarily operate for reliability reasons, and to set forth clear and transparent expectations for administrative compliance orders to ensure that compliance with these proposed rules can be achieved without impairing the ability of power companies and grid operators to maintain reliability. As such, these proposed rules provide the flexibility needed to avoid reliability concerns while still securing the pollution reductions consistent with section 111 of the CAA.

The EPA routinely consults with the DOE and FERC on electric reliability and intends to continue to do so as it develops and implements a final rule. This ongoing engagement will be strengthened with routine and comprehensive communication between the agencies under the DOE–EPA *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* signed on March 8, 2023.716 The memorandum will provide greater interagency engagement on electric reliability issues at a time of significant dynamism in the power sector, allowing the EPA and the DOE to use their considerable expertise in various aspects of grid reliability to support the ability of Federal and State regulators, grid operators, regional reliability entities, and power companies to continue to deliver a high standard of reliable electric service….

In addition, the EPA observes that power companies, grid operators, and State public utility commissions have well-established procedures in place to preserve electric reliability in response to changes in the generating portfolio, and expects that those procedures will continue to be effective in addressing compliance decisions that power companies may make over the extended time period for implementation of these proposed rules. In response to any regulatory requirement, affected sources will have to take some type of action to reduce emissions, which will generally have costs.

Some EGU owners may conclude that, all else being equal, retiring a particular EGU is likely to be the more economic option from the perspective of the unit's customers and/or owners because there are better opportunities for using the capital than investing it in new emissions controls at the unit. Such a retirement decision will require the unit's owner to follow the processes put in place by the relevant RTO, balancing authority, or State regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place.

In some rare instances where the reliability of the system is jeopardized due to extreme weather events or other unforeseen emergencies, authorities can request a temporary reprieve from environmental requirements and constraints (through DOE) in order to meet electric demand and maintain reliability. These proposed actions do not interfere with these already available provisions, but rather provides a long-term pathway for sources to develop and implement a proper plan to reduce emissions while maintaining adequate supplies of electricity.

C. Other Technical Issues raised about reliability implications of EPA's 2023 Proposal

In addition to the broader, thematic issues discussed in the prior section, several other technical reliability-related issues have been raised in stakeholder comments.

For example, although critics acknowledge that EPA discusses resource adequacy issues, EPA has been criticized for not having modeled or sufficiently accounted for *operational reliability* issues in considering the feasibility of the implementation of the proposed rule.[95]

NERC defines these two major reliability concepts in the following way: Resource adequacy is "'[t]he ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.'" By contrast, operational reliability, or system security, requires "[o]perating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."[96]

Resource adequacy considerations indeed differ from operational reliability ones, but EPA has not erred in modeling only the former. It is not reasonable to expect that at this point in time EPA should have modeled operational-reliability outcomes for the nation – that is, prior to actual promulgation of standards that (a) require state implementation plans to be developed, (b) require compliance obligations no earlier than 2030, and (c) allow for flexibility in owners' decisions about how to comply with the eventual standards and SIPs.

It would be unrealistic to expect that EPA (or even anyone with operational responsibility for the grid) to know the specific future compliance decisions of power plant owners that would be required to conduct meaningful detailed system impact studies across all regions of the country affected by the new standards starting nearly a decade from now. Operational security studies are location specific and quite granular in form. Given the long lead times available in the proposed regulatory approach, power plant owners will need to make decisions about technology and/or fuel choices, and/or whether to retire a unit or operate it at a low capacity factor in future years and when many other changes have occurred on the grid, in electricity markets, and so forth. Moreover, EPA has provided the types of flexible compliance options and timing runways that will allow decision makers about specific power plants' compliance to explore such operational security considerations at the time and location when they are most relevant.

Other commenters have raised concerns about the performance characteristics of different types of generating resources as assumed by EPA in its analyses.[97] Certainly, different generating technologies operate in different

---

[95] See, for example, PGen Comments.

[96] Paul Hibbard, Susan Tierney and Katherine Franklin, "Electricity Markets, Reliability and the Evolving Power System," June 2017, page 42, https://www.analysisgroup.com/globalassets/content/insights/publishing/ag_markets_reliability_final_june_2017.pdf, citing NERC's glossary of terms, available at http://www.nerc.com/files/glossary_of_terms.pdf.

[97] For example, a criticism is that technologies like wind or solar projects cannot be counted on to meet peak demand and thus have a lesser value from a resource adequacy point of view. PGen Comments; NRECA Comments.

modes, with combinations of characteristics – start-up and ramping speeds, fuel that is on-site (e.g., nuclear or conventional hydro) or subject to just-in-time delivery (e.g., natural gas) or tied to natural conditions (e.g., windiness or solar radiation), and so forth. Operational reliability depends on complex factors that system operators and electric companies bring to bear in real time, as my colleagues and I have previously explained:

> System operations are affected in real time by several things:
>
> - The mix of attributes of the resources on the system – their location, their fuel source, and the operating characteristics of the supply and demand resources;
> - The continuous variations in system conditions (e.g., variations in load as consumption changes; the sudden loss of a power plant or transmission line; changes in ambient conditions or sudden power outages due, e.g., to a storm); and
> - The system operator's practices and procedures for managing the changing conditions on the system at all times and in all places under that operator's responsibility, to assure that the system stays in balance.
>
> System security describes the ability of the system to meet ever changing system conditions, and to do so with enough redundancy in operational capabilities to manage and recover from a variety of potential system events – or "contingencies" – such as sudden and unexpected loss of generation, transmission, or load. System planners and operators must ensure that the technical capabilities of the mix of resources on the power system are capable of responding in real time to normal load changes and contingency events. This is needed to avoid the catastrophic wide-area failure of the bulk power system - such as a cascading outage covering one or more regions - that can come from unacceptable variations in system voltage and frequency….
>
> Importantly, system security, or operational reliability, does not result from a singular condition, such as the percentage of a system's capacity that operates in "baseload" mode. To maintain operational reliability, system operators use a combination of strategies, tools, procedures, practices, and resources to keep the entire system in balance even as conditions change on a moment to moment basis. The difficulty of this task largely results from several things, and occurs along different time frames.

In the end, on-the-ground reliability will result from a combination of technologies with different attributes (e.g., capacity, energy production, capacity factors, dispatchability, fuel delivery, ramping speed, ability to provide voltage support, and so forth). Operational reliability depends upon the attributes of thousands of physical elements of and market conditions affecting the bulk power system and local electricity distribution systems.

Some commenters[98] have argued that EPA has assumed an inappropriate "replacement rate" in modeling when renewable resources replace capacity lost when coal unit retire. While it is certainly the case that wind or solar

---

[98] PGen Comments.

facilities do not replace the combination of energy and capacity of some other types of technologies, such as nuclear plants, with their typical 90-percent capacity factors, or particular coal-fired or gas-fired generating units that have similarly high current capacity factors, there are many existing fossil units where extremely low capacity factors and fuel-delivery considerations (e.g., absence of firm gas pipeline delivery arrangements) suggest that it would be reasonable to presume a priori a "standard" replacement ratio across these technologies.

The more important consideration in modeling is to identify the amount of capacity AND energy that needs to be replaced on a system when determining what is needed upon the retirement of a unit with a particular operating profile (e.g., whether it is dispatchable with around the clock output capability and without fuel delivery constraints, versus an intermittent resource available either when its wind or solar energy source is available or when its electrical output can be combined with storage to provide dispatchable service subject to the operating constraints of the storage system). The availability of wind and solar output (e.g., capacity factor; capacity reliably available at the time of system peak) will depend upon a number of factors, such as the quality of the wind or solar resource, the height of towers, the age of the facility, the tilt of solar panels, the size of the solar installation). Capacity values are under review (and will continue to need to be assessed over time), not just of intermittent resources but also for resources that depend upon just-in-time deliveries of fuel (e.g., gas-fired power plants that require deliveries during extreme weather events).

EPA's analysis has been careful to provide reasonable estimates of future system conditions, and moreover the agency's design of the proposed rule provides many options for reasonable accommodation of and support for electric reliability considerations.

Attachment 1: Tierney et al., Reliability Tools and Practices (2015)

Susan Tierney, Paul Hibbard and Craig Aubuchon,

"Electric System Reliability and the EPA's Clean Power Plan: Tools and Practices,"

February 2015

Report link:
https://www.analysisgroup.com/globalassets/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_tools_and_practices.pdf

Electric System Reliability and EPA's Clean Power Plan: Tools and Practices

Analysis Group

Susan Tierney
Paul Hibbard
Craig Aubuchon

February 2015

Acknowledgments

This report provides a primer on various reliability issues facing the electric industry as it looks ahead to implementation of the Clean Power Plan, as proposed by the U.S. Environmental Protection Agency on June 2, 2014.

Taking into consideration the many comments of various parties filed on EPA's proposal, the report addresses issues that the nation and the electric industry need to address in order to simultaneously meet electric system reliability and carbon-emissions reduction obligations.

This is an independent report by the authors at the Analysis Group, supported by funding from the Energy Foundation.

The report, however, reflects the analysis and judgment of the authors only.

About Analysis Group

Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 600 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

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

Table of Contents

Executive Summary

Since the U.S. Environmental Protection Agency (EPA) proposed its Clean Power Plan last June, many observers have raised concerns that its implementation might jeopardize electric system reliability.

Such warnings are common whenever there is major change in the industry, and play an important role in focusing the attention of the industry on taking the steps necessary to ensure reliable electric service to Americans. There are, however, many reasons why carbon pollution at existing power plants can be controlled without adversely affecting electric system reliability.

Given the significant shifts already underway in the electric system, the industry would need to adjust its operational and planning practices to accommodate changes even if EPA had not proposed the Clean Power Plan.

In the past several years, dramatic increases in domestic energy production (stemming from the shale gas revolution), shifts in fossil fuel prices, retirements of aged infrastructure, implementation of numerous pollution-control measures, and strong growth in energy efficiency and distributed energy resources, have driven important changes in the power sector. As always, grid operators and utilities are already looking at what adjustments to long-standing planning and operational practices may be needed to stay abreast of, understand, and adapt to such changes in the industry.

The standard reliability practices that the industry and its regulators have used for decades are a strong foundation from which any reliability concerns about the Clean Power Plan will be addressed.

The electric industry's many players are keenly organized and strongly oriented toward safe and reliable operations. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations of the system, day in and day out.

http://imgkid.com/checklist-icon.shtml

Among other things, these "business-as-usual" procedures include:

- Assigning specific roles and responsibilities to different organizations, including regional reliability organizations, grid operators, power plant and transmission owners, regulators, and many others;
- Planning processes to look ahead at what actions and assets are needed to make sure that the overall system has the capabilities to run smoothly;
- Maintaining secure communication systems, operating protocols, and real-time monitoring processes to alert participants to any problems as they arise, and initiating corrective actions when needed; and
- Relying upon systems of reserves, asset redundancies, back-up action plans, and mutual assistance plans that kick in automatically when some part of the system has a problem.

http://www.bls.gov/ooh/installation-maintenance-and-repair/line-installers-and-repairers.htm

As proposed by EPA, the Clean Power Plan provides states and power plant owners a wide range of compliance options and operational discretion (including various market-based approaches, other means to allow emissions trading among power plants, and flexibility on deadlines to meet interim targets) that can prevent reliability issues while also reducing carbon pollution and cost.

EPA's June 2014 proposal made it clear that the agency will entertain market-based approaches and other means to allow emissions trading within and across state lines. Examples include emissions trading among plants (e.g., within a utility's fleet inside or across state lines), or within a Regional Transmission Organization (RTO) market. In this respect, the Clean Power Plan is fundamentally different from the Mercury and Air Toxics Standard (MATS) and is well-suited to utilize such flexible and market-based approaches. Experience has shown that such approaches allow for seamless, reliable implementation of emissions-reduction targets. In its final rule, EPA should clarify acceptable or standard market-based mechanisms that could be used to accomplish both cost and reliability goals.

Moreover, EPA has stated repeatedly that it will write a final rule that reflects the importance of a reliable grid and provides the appropriate flexibility.[1] We support such adjustments in EPA's final rule as needed to ensure both emissions reductions and electricity reliability.

Some of the reliability concerns raised by stakeholders about the Clean Power Plan presume inflexible implementation, are based on worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. There is no historical basis for these assumptions. Reliability issues will be solved by the dynamic interplay of actions by regulators, entities responsible for reliability, and market participants with many solutions proceeding *in parallel*.

Some of the cautionary comments are just that: calls for timely action. Many market participants have offered remedies (including readiness to bring new power plant projects, gas infrastructure, demand-side measures, and other solutions into the electric system where needed).[2] Indeed, this dynamic interplay is one reason why a recent survey of over 400 utility executives nationwide found that more than 60 percent felt optimistic about the Clean Power Plan and either supported EPA's proposed current emissions reduction targets or would make them more stringent.[3]

We note many concerns about electric system reliability can be resolved by the addition of new load-following resources, like peaking power plants and demand-side measures, which have relatively short lead times.[4] Other concerns are already being addressed by ongoing work to improve market rules, and by infrastructure planning and investment. A recent Department of Energy (DOE) report found that while a low-carbon electric

[1] See, for example, the January 6, 2015 blog post of Janet McCabe, EPA's Acting Administrator for Air and Radiation, "Time and Flexibility: Keys to Ensuring Reliable, Affordable Electricity," http://blog.epa.gov/epaconnect/2015/01/time-and-flexibility/. Also, see EPA's October 2014 Notice of Data Availability (NODA) that sought comments on, among other things, the potential to change the phase-in of emissions reductions to accommodate, for example, any constraints in natural gas distribution infrastructure, or how states could earn compliance credits for actions taken between 2012 and 2020.

[2] Although we think it is ultimately a good thing that the industry is paying close attention to reliability issues – so that any potential problems can be avoided through planning and infrastructure – we do note that serious questions have been raised about the assumptions used in recent reliability assessments performed by the North American Reliability Corporation (NERC). For example, Brattle Group's February 2015 report found that NERC failed to account for how industry is likely to respond to market and operational changes resulting from the Clean Power Plan. See Jurgen Weiss, Bruce Tsuchida, Michael Hagerty, and Will Gorman, "EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review," The Brattle Group, February 2015.

[3] The same survey found that utility executives believe that distributed energy resources offer the biggest growth opportunity over the next five years, and more than 70 percent expect to see a shift away from coal towards natural gas, wind, utility-scale solar and distributed energy. Utility Dive and Siemens, "2015 State of the Electric Utility Survey Results," January 27, 2015. The survey included 433 U.S. electric utility executives from investor-owned and municipal utilities, and electric cooperatives.

[4] Our report provides typical timelines for various types of resource additions in Section II.

system may significantly increase natural gas demand from the power sector, the projected incremental increase in natural gas pipeline capacity additions is modest (lower than historic pipeline expansion rates), and that the increasingly diverse sources of natural gas supply reduces the need for new pipeline infrastructure.[5]

Some other comments raise the reliability card as part of what is – in effect – an attempt to delay or ultimately defeat implementation of the Clean Power Plan. We encourage parties to distinguish between those who identify issues and offer solutions, and those who (incorrectly) suggest that reducing carbon pollution through the Clean Power Plan is inconsistent with electric system reliability.

In the end, because there are such fundamental shifts already underway in the electric industry, inaction is the real threat to good reliability planning. Again, there are continuously evolving ways to address electric reliability that build off of strong standard operating procedures in the industry.

There are many capable entities focused on ensuring electric system reliability, and many things that states and others can do to maintain a reliable electric grid.

First and foremost, states can lean on the comprehensive planning and operational procedures that the industry has for decades successfully relied on to maintain reliability, even in the face of sudden changes in industry structure, markets and policy.

Second, states should take advantage of the vast array of tools available to them and the flexibility afforded by the Clean Power Plan to ensure compliance is obtained in the most reliable and efficient manner possible. Given the interstate nature of the electric system, we encourage states

Entities with roles to play as part of ensuring electric system reliability and timely compliance with EPA's Clean Power Plan	
Electric Reliability Entities	Federal Energy Regulatory Commission (FERC)
	North American Electric Reliability Corporation (NERC)
	Regional Reliability Organizations
	Electric System Operators and Balancing Authorities
Other public entities	Environmental Protection Agency (EPA)
	States (air agencies, public utility commissions, energy offices, state legislatures)
	Other federal agencies (Department of Energy, Energy Information Administration)
Entities involved with markets, resource planning, procurements	Wholesale market administrators
	Electric utilities (investor-owned, municipal utilities, cooperatives, joint action agencies
Other organizations that have a role to play	Non-utility generating companies and providers of other technologies
	Interstate natural gas pipeline companies (and storage suppliers)
	North American Energy Standards Board (NAESB)
	Energy efficiency program administrators
	Others

[5] U.S DOE, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector," February 2015.

to rely upon mechanisms that facilitate emission trading between affected power plants in different states. Doing so will increase flexibility of the system, mitigate many electric system reliability concerns, and lower the overall cost of compliance for all.[6]

In this report we identify a number of actions that the Federal Energy Regulatory Commission (FERC), grid operators, states, and others should take to support electric system reliability as the electric industry transitions to a lower-carbon future. We summarize our recommendations for these various parties in tables at the end of our report.

In the end, the industry, its regulators and the States are responsible for ensuring electric system reliability while reducing carbon emissions from power plants as required by law. These responsibilities are compatible, and need not be in tension as long as all parties act in a timely way and use the many reliability tools at their disposal.

We observe that, too often, commenters make assertions about reliability challenges that really end up being about cost impacts. Although costs matter in this context, we think it is important to separate reliability considerations from cost issues in order to avoid distracting attention from the actions necessary (and feasible) to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution precisely because they fail to account for the cost of unacceptable system outages to electricity consumers.

Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs. There is no reason to think that cost and reliability objectives cannot be harmonized within a plan to reduce carbon pollution.

[6] As we will discuss in a series of regional reports, others have already identified that regional strategies will minimize overall compliance costs. For example, the Midcontinent Independent System Coordinator (MISO) estimated that a regional carbon constraint approach could save up to $3 billion annually relative to a sub-regional or individual state approach. MISO, "Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units," November 2014. See also, "Statement of Michael J. Kormos, Executive Vice President – Operations, PJM Interconnection, FERC Docket No. AD15-4-000, Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure," February 19, 2015.

This paper is designed to:

- Describe the changes underway in the industry which set the stage for the continued evolution of reliability tools and practices;
- Provide a "reliability 101" primer to describe what "electric reliability" means to system planners and operators, and why specific standard practices are so important to assuring electric reliability;[7]
- Summarize reliability concerns expressed by various stakeholders;
- Explain the ways that standard operating procedures can address these concerns; and,
- Recommend actions that can be taken by various actors in the electric industry to assure that the Clean Power Plan's goals do not undermine reliable power supply.

Our recommendations can be found in tables following the Executive Summary.

[7] This report also includes a glossary of acronyms used in our report.

Recommendation Tables

Table 1
Key Players in the Clean Power Plan and Available Tools

Entities	Roles and Responsibilities
Entities with direct responsibility for electric system reliability	- FERC (under the Federal Power Act (FPA)) - NERC (as the FERC-approved Electric Reliability Organization under the FPA) - Regional Reliability Organizations (RROs) - System operators and balancing authorities (including Regional Transmission Organizations (RTOs) and electric utilities) - States (for resource adequacy)

Other public agencies with direct and indirect roles in the Clean Power Plan	- U.S. Environmental Protection Agency (EPA)
	- State executive branch agencies:
	    - Air offices and other Environmental Agencies
	    - Public Utility Commissions (PUCs)
	    - Energy Offices
	    - Public authorities (e.g., state power authorities)
	- State governors and legislatures
	- U.S. Department of Energy (DOE)
	- Energy Information Administration (EIA)

Owners of existing power plants covered by 111(d) of the Clean Air Act	- Electric utilities
	    - investor-owned utilities
	    - municipal utilities
	    - electric cooperatives
	    - joint action agencies
	- Non-utility power plant owners

Markets and Resource Planning/ Procurement Organizations	- Organized markets administered by RTOs (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, SPP).
	- Electric utilities with supply obligations & subject to least-cost planning processes:
	    - Many utilities (including joint action agencies) operate under requirements to use a combination of planning and competitive procurements (with or without self-build opportunities
	    - Transmission owners also have transmission planning requirements
	- Private investors (including non-utility companies) responding to market signals and seeking to develop/permit/construct/install/operate new resources (including new power plant projects, demand-response companies, merchant transmission companies, rooftop solar PV installation companies, etc.)

Others	- North American Energy Standards Board (NAESB) for setting electric & gas standards - Administrators/Operators of CO_2 allowance-trading systems - Administrators/Operators of energy efficiency programs - Fuel supply and delivery companies (gas pipeline and/or storage companies; gas producers; coal producers; coal transporters) - Energy marketing companies - Emerging technology providers – including, e.g., storage system providers, companies providing advanced communications and "smart" equipment, etc.

Table 2
FERC, NERC, and RROs' Potential Actions to Address Reliability Issues

Electric Reliability Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
FERC: - Adoption of federally-enforceable reliability requirements and standards - Oversight of NERC and all bulk power system operators - Oversight of interstate natural gas pipeline owners/operators, with authority to approve interstate pipeline expansions - Authority over transmission planning, tariffs, open-access - In organized markets, authority over market rules (including capacity markets, provision of ancillary services providing various attributes to system operators) - Interagency coordination with EPA, DOE	Consider: - Requiring NERC, RROs, and system operators/balancing authorities to periodically assess potential reliability impacts of CPP with geographic scope appropriate to the reliability entity. The assessments could identify specific concerns, and develop backstop solutions – Preliminary assessments starting at end of 2015/early 2016, to inform state action taking into account known policy, practices, resources in the relevant area – Reliability assessments at the time of proposed state plans – Reliability assessments annually up through early 2020s - Continuing to evaluate the adequacy of current FERC gas/electric coordination policies in light of *incremental* changes resulting from CPP relative to trends already underway in the industry - Eliciting filings from RTOs and other transmission companies about any new planning tools, notice provisions for potential retirements, information reporting, new products, minimum levels of capability with various attributes - Inquiring into new natural gas policies to support wider interdependence with electric system reliability (e.g., incentives for development of gas delivery/storage infrastructure) - Working with states to consider mechanisms to afford bulk-power system grid operators' greater visibility into generating and demand-side resources on the distribution system - Providing guidance outlining compliance strategies that would require approvals of the FERC under the FPA (versus approaches that might not require such)
NERC – Reliability Standards, compliance assessment, and enforcement – Annual & seasonal reliability assessments – Special reliability assessments	Consider: – Continuing to conduct special assessments of impact of CPP on reliability (as it periodically does for other developments in the industry) – Preliminary assessments in parallel with final rule development,(in 2015) and development of State Plans (2015/2016) – Final assessments upon finalization of State Plans (2016+) – Assess whether any new standards relating to Essential Reliability Services need to be modified in light of electric system changes occurring as part of the industry's response(s) to CPP
Regional Reliability Organizations – Annual & seasonal reliability assessments – Special reliability assessments – Coordination with neighboring RROs	Consider: – Conducting special assessments of impact of CPP on reliability – Preliminary assessments in parallel with final rule development,(in 2015) and development of State Plans (2015/2016) – Final assessments upon finalization of State Plans (2016+)

Table 3
Grid Operators' Potential Actions to Address Reliability Issues

Electric Reliability Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

System Operators and Balancing Authorities
– On-going annual & seasonal reliability assessments, including transmission planning
– Special reliability assessments
– Coordination with neighboring systems
 	
Note: Some of these entities also fulfill market, resource planning and procurement functions (described further below)
	Consider
	– Conducting special assessments of impact of CPP on system reliability
	  – Preliminary assessments in parallel with final rule development (in 2015) and development of State Plans (2015/2016)
	  – Final assessments upon finalization of State Plans (2016+)
	– Identifying specific areas of concern (e.g., notice period for potential unit retirements; need for more routine anticipatory analyses in transmission planning to explore "what if" changes occur on the system; identification of zones with violations of reliability requirements and any specific units needed for reliability pending resolution of the violation)
	– Working with stakeholders (including environmental agencies in relevant states) to develop proposals for reliability safety value to ensure mechanism to fully offset CO_2 emission impacts when use of a safety valve is triggered
	– Working with counterparts in natural gas industry to harmonize business practices, develop improved inter-industry forecasting tools, coordinate operating days/market timing, share information, identify specific natural gas infrastructure needs
	– Refreshing policies and practices to assure technology-neutral and competitively neutral means for providing reliability services (both resource adequacy and system operations)
	  - Technology neutrality should recognize the different attributes needed for essential reliability services, but be supportive of generation, transmission and demand-side solutions for providing such attributes
	– Working with state officials and distribution utilities within their relevant geographies to explore ways to expand the visibility (e.g., through communications and information systems) of the system operator into distribution system resource operations (i.e., distributed variable resources such as solar PV); incorporate into planning activities
	– Continuing to improve meteorological forecasting capabilities

Table 4
Other Federal Agencies' Potential Actions to Address Reliability Issues

Other Public Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

EPA
- **Issuing the final Clean Power Plan regulation**
- **Responsibility for finalizing standards for new power plants (Section 111(b))**
- **Responsibility for administering federal air, water, and waste pollution standards**
	Consider:
	- Clarifying acceptable standard market mechanisms that could be used to accomplish emission-reduction and reliability goals in economically efficient ways
	- Providing guidance on allowing one or more forms of a reliability safety valve, *with the condition* that overall emissions over the interim period (e.g., 2020-2029) are equal to or better than the plan without a triggering of the reliability safety valve. Examples might include:
	  - Allowing the reliability safety valve as proposed by the RTO/ISO Council (with the noted CO_2 emissions offset condition)
	  - Requiring/allowing temporary exemptions/modifications of timing/quantity requirements in State Plans
	  - Providing guidance about how states may propose to alter compliance deadlines/requirements where needed for reliability, should such issues arise over time
	- Requiring States to include reliability assessments in final State Plans (not for EPA to review/approve, but rather to ensure that such studies are conducted)

Other federal agencies - **DOE** - **EIA**	Consider: - Investigating additional reporting requirements by members of the industry - Conducting studies and analyses that examine physical capabilities of more integrated gas and electric system - Identifying CPP compliance issues as qualifying for DOE Critical Congestion Areas and Congestion Areas of Concern, and/or "national interest electric transmission corridors" under the Energy Policy Act of 2005

Table 5
States' Potential Actions to Address Reliability Issues

Other Public Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

States
– Air agency:
  – obligation to submit State Plans to EPA
  – reviewing/approving any modification to air permits of affected generating units
– Executive and legislative responsibility for energy, environmental laws and regulations
– Oversight over regulated electric and natural gas utilities (public utility commissions) – including ratemaking, programs (e.g., energy efficiency), planning and resource procurement
– Coordination with neighboring states
– Engagement in regional planning, operational, and market rules and procedures
– Siting/permitting of electric energy infrastructure and local gas distribution facilities
	Consider:
	– Proactively (i.e., now) engaging with state utilities and state/regional system operators in evaluation of potential CPP reliability impacts, and identification of reliability solutions (including supporting preliminary assessments in parallel with development of State Plans (2015/2016), and final assessments upon finalization of State Plans (2016+))
	– Establishing as part of the State Plan an annual state reliability evaluation, and identification of/commitment to take steps and measures in the future in response to any identified reliability concerns. This could include a framework for allowing compliance waivers and extensions in the early years in the event that reliability issues arise circa 2020, combined with requirements on state and/or compliance entities for provisional CO_2 reductions over transition period to make up for waivers/extensions in early years (e.g., to arrive at same cumulative emissions over the period)
	- Incorporating conditions in air permits to reflect operating limits (e.g., total emissions within an annual period)
	- Creating flexible implementation plans (e.g., mass-based models) and multi-state programs (e.g., regional cap/trade) to mitigate potential reliability impacts and operational flexibility across regions that reflect the normal operations of interconnected electric system
	  - State or regional cap and trade programs
	  - "Bubbling" of requirements across units owned by common owner (e.g., within one state or across states through bilateral state agreements/MOUs)
	– Developing statewide policies and measures for compliance that support reliability (energy-efficiency/renewable energy programs, including measures beyond Investor Owned Utility funded programs), for example:
	  – Clean energy standards
	  – Investment in emerging or early-stage technologies (*e.g.*, storage), public-private partnerships, tax and investment credits
	  – Protocols for counting Energy Performance Savings Contracts in State Plans
	– Reviewing need to modify permitting/siting regulations to accommodate dual-fuel capability of gas-fired power plants
	– Reviewing need to modify administrative or procedural measures to expedite siting, zoning, permitting of needed energy infrastructure (renewables, other power plants, transmission, LNG storage)
	– Instituting new entities (e.g., natural-gas buying authorities) to serve as contracting entity to support long-term commitments that may be necessary for gas system expansion
	– Requiring longer advance notice of power plant retirements

Table 6
Organized Markets' & Electric Utilities Potential Actions to Address Reliability Issues

Entities Involved with Markets, Resource Planning, and Procurements	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

Wholesale Market Administrators (Generally, Bulk Power System (BPS) Operators in Competitive Market Regions)
– **Markets designed and administered to minimize costs *subject to the constraint* that all reliability requirements of the system are met**
	Consider:
	– Adding technology-neutral and competitively neutral market rules/products to add incentives for new reliability attributes.
	   – Local (zonal/load pocket) capacity and energy market pricing; changes to scarcity pricing
	   – Reliability attributes for system security (greater quantities of spinning or non-spinning reserves; AGC; ramping/load-following; reactive power; on-site fuel; frequency response; black start capability)
	– Establishing or clarifying, where necessary, expectations around unit performance during shortage or scarcity conditions
	– Clarifying how normal dispatch processes incorporate current restrictions on unit operations (including emissions limits, ramping periods, etc.), and how similar operational restrictions (if any) resulting from Clean Power Plan compliance would be incorporated in system operations
	– Establishing or clarifying, where needed, provisions for the creation of reliability must run (RMR) contracts for generators needed for reliability that would otherwise retire – conditioned upon permit restrictions that account for CO_2 emissions offsets
	– Establishing or clarifying, where needed, procedures to minimize duration of RMR contracts through development of utility or market responses (generation, transmission)
	– Identifying any changes in forward capacity markets for the period starting in 2020

Vertically-Integrated Utilities, Cooperatives, Municipal Light Companies
– **Long-term resource planning**
– **Obligation and opportunity to develop and obtain cost recovery for necessary demand, supply, and transmission investments and expenses**
– **Obligation to maintain power system reliability**
– **In some states, integrated resource planning and/or resource need/procurement processes**
– **Coordinated operation of systems with neighboring utilities**
	Consider:
	– Conducting forward-looking assessments of potential impacts on system reliability of CPP implementation
	   – Preliminary assessments prior to and during final rule development and SIP implementation
	   – Final assessments upon finalization of SIP
	– Developing or expanding long-term integrated resource planning processes for timely and practical incorporation of CPP compliance requirements
	– Incorporating all potential short- and long-term measures (supply and demand; generation and transmission) to address significant changes during CPP transition period
	– Engaging in coordination with neighboring utilities around local reliability concerns tied to CPP implementation

Table 7
Other Organizations' Potential Actions to Address Reliability Issues

Other Organizations that have a Role To Play in Assisting in Reliable and Effective Industry Compliance	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
Non-Utility Generating Companies	Consider: - Responding to signals in organized wholesale markets and in response to competitive solicitations by electric utilities
Interstate Natural Gas Pipeline Owners/Operators – Coordination among NGP owners/operators – Coordination with BPS operators – Development of new pipeline capacity	Consider: – Improving coordination with system operators – e.g., harmonize standards and practices, coordinate operating days/market timing, share information, etc.
NAESB - Working with industry stakeholders to develop standards for operations in electric and gas industry	Consider: – Periodically convening industry sector discussions about continuing need to harmonize standards in the electric and gas industries
Administrators of Allowance Trading Programs (e.g, RGGI, California, new ones)	Consider: - Establishing new "plug and play" programs that allow states to join with relatively administrative ease
Administrators of Energy Efficiency Programs	Consider: - Establishing products to offer to generating companies to 'purchase' program credits to offset emissions, subject to strict measurement and verification
Energy Service Companies (ESCos)	Consider: - Working with State agencies to develop mechanisms to incorporate energy-savings-performance contracts into State Plans

I. Context

In June 2014, the U.S. Environmental Protection Agency (EPA) issued its proposed Clean Power Plan, designed to reduce carbon dioxide (CO_2) emissions from existing fossil-fuel power plants in the United States. The final rule, which is now anticipated to come out in mid-2015, will require each of the 49 states with covered power plants to prepare and submit plans for how they propose to reduce emissions from the plants in their state. Although the features of the final regulation will undoubtedly change in light of the many comments filed, EPA's current proposal requires states and affected electric generating units (EGUs) to demonstrate progress to reduce emissions starting in 2020, with subsequent reductions thereafter. This new policy will eventually affect over half of the nation's generating capacity and all but the smallest fossil fuel generating units.[8]

In light of the broad scope of the regulation, many stakeholders have raised concerns about whether EPA's proposal will jeopardize the reliability of the electric system. In Washington, in state capitols, in media alerts, in comments filed at the EPA, and elsewhere, many public officials, electric utilities, industry reliability organizations, and others have been demanding

[8] An affected electric generating unit (EGU) is defined broadly, as any boiler, integrated gasification combined cycle (IGCC), or combustion turbine (in either simple cycle or combined cycle configuration) that (1) is capable of combusting at least 250 million Btu per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input and (3) sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system (Proposed Rule, Federal Register, Vol. 79, No. 117, June 18, 2014, page 34854). Generating units estimated to be subject to EPA's Clean Power Plan:

SNL Financial (as of 2-2015)	Generating Units Likely to be Directly Covered by Section 111(d)*		Total Grid-Connected Generating Capacity in the U.S. (GW)	111(d) Capacity as Share of Total Capacity (%)
	(# Units)	Summer Capacity (GW)	Summer Capacity (GW)	Summer Capacity (GW)
Coal	922	300	303	99%
Gas	2,137	334	464	72%
Oil	62	17	39	44%
Total Fossil	3,121	651	806	81%
All Capacity			1,151	57%

* Includes all existing or under development steam turbines and combined cycle units greater than 25 MW, and any natural gas combustion turbines with generation greater than 219,000 MWh.
Source: SNL Financial, Power Plant Unit Database.

that the changes introduced by the Clean Power Plan not come at the expense of electric reliability.[9]

For many decades, such cautions have appeared whenever major events – such as major new environmental regulations affecting power plants or structural changes to introduce competition in the electric industry – occur that could affect electric system reliability.[10]

Indeed, well before the EPA issued its proposal, various reliability organizations had already begun to anticipate how changes underway in the electric industry would necessitate modifications in traditional ways to plan for and operate the electric system. For example, the North American Electric Reliability Corporation (NERC) – the nation's electric reliability standards organization – issued a "concept paper" in October 2014, in which NERC describes the many ways that today's reliability procedures will need to evolve to keep ahead of the changing character of the electric "resources" that connect with the grid.[11]

NERC's paper, which was in development well before the EPA issued its Clean Power Plan (and is different from NERC's November 2014 assessment relating to the EPA proposal), begins by recognizing that the

> North American BPS [bulk power system] is experiencing a transformation that could result in significant changes to the way the power grid is planned and operated. These changes include retirements of baseload generating units; increases in natural gas generation; rapid expansion of wind, solar, and commercial solar photovoltaic (PV) integration; and more prominent uses of Demand Response (DR) and distributed generation…. As the overall resource mix changes, all the aspects of the ERSs [Electric Reliability Services] still need to

[9] See discussion in Section III and the Appendix to this paper. Note that even the leadership of the EPA and the President of the United States have insisted upon design and implementation of the Clean Power Plan in ways consistent with electric system reliability. See, for example: President Obama's Presidential Memorandum ("Power Sector Carbon Pollution Standards," June 25, 2013), in which the President directed the EPA to issue regulations to control CO_2 emissions from the power sector, and included the following instructions: "In developing standards, regulations, or guidelines … [EPA] shall ensure, to the greatest extent possible, that you: …(v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses…" Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards

Also, see: Statement of Gina McCarthy, Nominee for the Position of Administrator of the EPA, Before the Environment and Public Works Committee, U.S. Senate, April 11, 2013; and the January 6, 2015 blog post of Janet McCabe, EPA's Acting Assistant Administrator for Air and Radiation, "Time and Flexibility: Keys to Ensuring Reliable, Affordable Electricity," http://blog.epa.gov/epaconnect/2015/01/time-and-flexibility/.

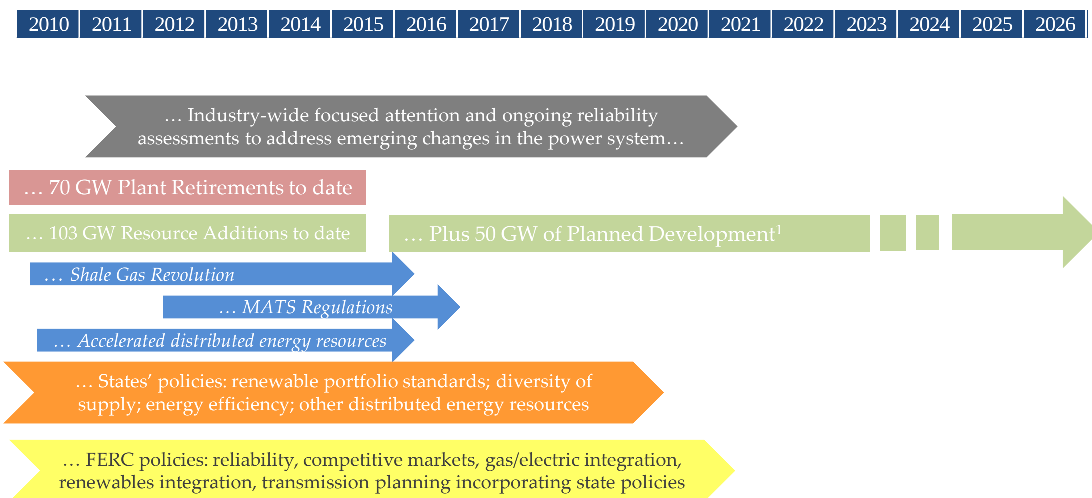
[10] Notably, this has occurred in conjunction with: the EPA "NO_x SIP call" which affected 23 states in the 1990s; state and federal policies related to electric industry restructuring in the 1990s: the Cross-State Air Pollution Rule (CSAPR) and MATS rule; and with on-going increases in the amount of distributed energy resources and intermittent/non-dispatchable resources on the grid.

[11] NERC, "Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability," October 2014. Hereinafter referred to as "NERC Essential Reliability Services Report".

> be provided to support reliable operation. ERSs are technology neutral and must be available regardless of the resource mix composition.[12]

Those transformations have been in the works for years – in part as a result of the shale gas revolution, changes in the relative prices of fossil fuels, state policies and federal laws encouraging greater use of renewable energy and energy efficiency, declines in wind and solar technology costs, retirements of old and highly polluting coal plants, retirements of a handful of nuclear plants (in some cases for safety reasons, and others for economic reasons), and strong interest by many customers in exploring ways to better manage their own energy use.[13] We depict these changes occurring in parallel in Figure 1, below.

Figure 1
Timeline of Changes Underway in the Electric Industry



[1] Includes retirements/additions announced for 2015 and units that are mothballed or out of service. Planned units include those under construction or in advanced development. Source for MW of retirements and planned additions: SN Financial, Accessed February 2015

As always, grid operators and utilities have implemented and adjusted long-standing planning and operational practices to stay abreast of, understand, and adapt practices to address reliability issues related to such changes in the industry. Given the multiple pressures on the electric power sector, such actions would be needed today even if EPA had not proposed to control carbon pollution in the Clean Power Plan.

---

[12] NERC Essential Reliability Services Report, page iii. The scope of work for this report was adopted by NERC in March of 2014, before the EPA Clean Power Plan was issued in proposed form in June, 2014.

[13] See, for example: Susan Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 8, 2014, pages 23-46.

Indeed, many organizations besides NERC have also been flagging the need to address reliability issues as the industry undergoes significant change. For example:

- The Federal Energy Regulatory Commission's (FERC) attention to gas-electric coordination as the two industries become increasingly dependent on each other,[14] and transmission companies and Regional Transmission Organizations (RTOs) plan for integration of variable generating resources and transmission requirements driven by public policies of state and local governments;[15]
- Studies by the Midcontinent ISO (MISO) of gas infrastructure,[16] and MISO's support for policies addressing transmission implications of the region's growing quantities of wind and other renewable resources;[17]
- ISO-New England's (ISO-NE) continuing analysis of that region's deepening reliance on gas-fired generating facilities, near-term generator retirements, and need to integrate deepening amounts of renewable resources;[18]

---

[14] FERC Commissioner Philip Moeller first requested comments on gas-electric coordination in February 2012. Since that time, the FERC has held nine regional conferences to address the issue. See FERC "Natural Gas – Electric Coordination." Available: http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp for additional detail. In 2013, FERC Chairman Cheryl LaFleur and Commissioner Moeller testified before Congress on "The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges". The Commissioners noted that gas-electric coordination was and is a growing and important trend due to falling natural gas prices and substantial domestic supplies. FERC receives quarterly updates from its staff on the status of developments in the industry regarding gas/electric coordination issues. http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp. Note too that in response to a directive from FERC, the North American Energy Standards Board (NAESB) undertook a process to develop some new standards for both electric and natural gas industries, which were described in a report submitted to FERC on September 29, 2014.

[15] On July 21, 2011, FERC issued Order 1000 (Docket No. RM10-23-000), in which the agency required, among other things, that each public utility transmission provider: (1) participate in a regional transmission planning process that produces a regional transmission plan; and (2) consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs. FERC Fact Sheet, Order 1000, http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-factsheet.pdf. On June 22, 2012, FERC issued the final rule in its docket (RM10-11-000) on Integration of Variable Energy Resources, in which it ordered a number of changes in interconnection agreements, transmission tariffs and cost recovery for regulation reserves to better accommodate renewables reliably and efficiently. 139 FERC ¶ 61,246, FERC Order No. 764.

[16] MISO released its first gas-electric interdependence study in February 2012; it reviewed existing gas pipeline capacity to serve existing electric generation and additional capacity that could be added in the future, and signaled to the MISO and stakeholders that an increase in gas-fired generation will require an "improved collaborative process between pipelines, power generators, and regulators to coordinate natural gas infrastructure projects." Gregory L. Peters, "Gas and Electric Infrastructure Interdependency Analysis," Prepared for the Midwest Independent Transmission System Operator, February 22, 2012, page. 12.

[17] MISO's "Multi-Value Project Portfolio Analysis" of transmission projects will support delivery of up to 41 million MWh of wind energy. Available: https://www.misoenergy.org/PLANNING/TRANSMISSIONEXPANSIONPLANNING/Pages/MVPAnalysis.aspx

[18] ISO-NE first identified these issues in 2010. In 2013, ISO-NE's Chief Executive Officer, Gordon van Welie, stated: "It is clear that resolving these challenges will not be simple, and it will take several years to realize the benefits of the solutions… It is important to remember that, often, the best ideas are born out of necessity. Today the power system faces significant and formidable obstacles. But tomorrow, it will be smarter, stronger, and more environmentally sound because of our collective efforts." ISO-NE, "2013 Regional Electricity Outlook," January 31, 2013, page 8.

- Starting in 2010, calls by the American Public Power Association (APPA) to pay greater attention to the impacts of distributed generation and increased natural gas demand for power generation;[19]
- The Electric Reliability Council of Texas' (ERCOT) ongoing analysis of wind integration as part of its bi-annual Long Term System Assessment;[20]
- The review by the five major electric utilities in California of the implications of a potential significant increase in the state's renewable portfolio standard,[21] and the California ISO's (CAISO) solicitation of more flexible resources to support integration of renewables;[22]
- PJM Interconnection's (PJM) recent capacity performance proposal, in response to concerns raised by unavailable conventional generation capacity during the 2013-2014 polar vortex;[23] and
- New York ISO's (NYISO) ongoing evaluation of reliability needs, including scenarios that account for environmental regulations, increasing penetration of renewable resources, and natural gas fuel availability.[24]

These studies and activities – and others like them – illustrate that our electric system operators, planners, regulators, and others are stepping up to the plate (as they typically do) to grapple with ways to make sure that the future electric system is as reliable as the one we count on today. And their analyses reflect the reality that these trends are occurring as a result of economic, policy and regulatory forces that are independent of EPA's Clean Power Plan.

The value of such "reliability alerts" is that they identify ways in which changes in policy, economics, technology, and law affecting the electric industry intersect with the physics and engineering of interconnected electric systems. All parts of the system must pay attention to certain imperatives of the others.

---

[19] See, for example, Aspen Environmental Group, "Implications of Greater Reliance on Natural Gas for Electricity Generation," prepared for American Public Power Association, July 2010.; and American Public Power Association, "Distributed Generation: An Overview of Recent Policy and Market Developments", November 2013.

[20] See, for example, ERCOT, "Long-Term System Assessment for the ERCOT Region," December 2012, which examined the implications of introducing significant wind generation and new gas-fired power plants on to the ERCOT Texas system.

[21] Energy+Environmental Economics, "Investigating a Higher Renewables Portfolio Standard in California," January 2014.

[22] California Independent System Operator Corporation Reply Comments on Workshop issues, before the Public Utilities Commission of the State of California, In the Matter of "Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations." Rulemaking 11-10-023, April 5, 2013.

[23] PJM Staff Proposal, "PJM Capacity Performance Proposal", August 20, 2014.

[24] NYISO conducts a detailed "Reliability Needs Assessment" every two years. See, for example, NYISO, "2014 Reliability Needs Assessment," Final Report, September 16, 2014.

Certainly, the shale gas 'revolution' has introduced significant quantities of domestically supplied natural gas at prices which compete with coal, the historically dominant domestic fossil fuel for power generation. This new reality presents economic opportunities to the power system, with cost and environmental benefits for households and businesses. At the same time, however, lower-cost natural gas introduces new issues that must be addressed in the standards, business practices and regulation of both the electric and gas industries: for example, there are new issues surrounding ensuring adequate fuel-transportation and storage arrangements. States' policies to rely more heavily on domestic wind and solar generation also introduce new challenges: grid operators must plan to operate their systems reliably with greater reliance on less dispatchable resources (or in some cases resources that cannot be 'seen' on the system by grid operators, when the resources are behind the meters of customers).

Reliability organizations and grid operators (including NERC, Regional Transmission Organizations (RTOs), electric utilities, and others) are already facing the implications of these trends. They are doing what we count on them to do: looking ahead to see what's on the horizon and identifying reliability-related issues that require adjustments to planning, markets, or operations. They are identifying issues that arise from economic, technological, legal or policy changes. They are developing new analytic tools to better understand how factors like the weather (or wind or sun/cloud-cover conditions) affect power system operations. They are identifying possible, if not likely, changes in power supplies, and indicating where and when new resources might be needed in the years ahead. They are working with transmission owners, power plant companies, government regulators, reliability coordination organizations, consumer representatives, and others to identify changes that may be required in operating standards, market products, and practices.

This is standard operating procedure in an industry with a history with strong legal, cultural, and organizational incentives to do what it takes to make sure that a world-class reliable electric system remains a bedrock of the American economy and society. Recent calls for action to ensure that the Clean Power Plan does not jeopardize electric system reliability should be viewed in that context: people are doing their jobs, not necessarily trying to impede the Clean Power Plan.

II. What Do We Mean by "Electric System Reliability"?

What is reliability, and why does it matter?

http://www.dailymail.co.uk/news/article-2226399/Sandy-Vast-majority-ConEd-wont-power-10-days--Manhattan-hopes-lit-Saturday.html

Most electricity users think of reliability in terms of how often their power shuts off and how long it takes to get it back on. These familiar reliability annoyances typically result from events affecting the local distribution system, such as a snowstorm or hurricane knocking out power lines or a car hitting a power pole.

While critically important to electricity users,[25] such events are not the main concern of observers considering the implications of EPA's Clean Power Plan. What they worry about is whether the overall electric system can do its job, day in and day out, even if one neighborhood or another loses its power.

This other kind of reliability is known as "bulk power system"[26] reliability (and what we call "system reliability" and what insiders sometimes call "BPS" reliability). Outages due to system failures differ from local outages in fundamental ways: in how they can arise; in the geographic scope of power interruptions; in the process and timing of power restoration; in the magnitude of adverse consequences; and, in terms of the parties responsible to fix the problems. The sheer scale of potential human health, safety, and economic impacts is what separates system reliability from local reliability, and dictates a high degree of vigilance on the part of regulators and the industry to avoid system-reliability failures.[27]

[25] Electricity consumers are acutely aware of how inconvenient and costly outages can become, and of course may not care whether an outage is local or system-wide, in terms of the disruptive impacts on their lives. At the state level, maintaining reliable service is a fundamental obligation of every local utility, and state public utility commissions (PUCs) measure the performance of local utilities in maintaining local reliability over time through measurements that track the frequency and duration of outages. In many states, utilities can be fined heavily for poor reliability performance tied to local distribution-system outages. In contrast, system power failures – which are far less common – generally involve events affecting power plants and transmission lines and a wider geographic area of the grid, with reliability enforcement subject to the jurisdiction of FERC under then Federal Power Act (FPA).

[26] A Bulk Power System (BPS) generally covers a wide geographic region, and includes the generating resources, transmission lines, and associated equipment and systems used to operate the integrated electric system within the region. BPSs generally do not include the lower-voltage distribution systems of local utilities, which deliver power from the BPS to end-use customers.

[27] This is not to say that local distribution system circumstances can never create system reliability challenges. Given that the electric system has to maintain customer demand (load) and supply in balance at all times, a major storm that causes local lines to

For this reason, multiple entities (including those in Table 8) constantly monitor conditions on the overall power system to assure that the overall system operates with a high degree of reliability. System planners, reliability organizations, power companies and regulators look many years ahead, to analyze changing conditions and flag issues on the horizon that need attention. From one season to the next, they review whether there will be enough resources to meet peak demand. Closer to real time, system operators monitor whether power plants are out for maintenance, whether temperature conditions will produce higher than expected demand, and myriad other conditions so that they can get ready for the next day's operations. And in real time, on a second-by-second basis, grid operators have to monitor, and manage the "balance" of the system so that supply equals demand within tolerable operating limits (i.e., "frequency"). Thus, across very different time frames, many actors in the industry work to assure that the system performs with impeccable reliability levels.

Table 8
Entities Responsible for Electric System Reliability

Organization	Roles and Responsibilities
Federal Energy Regulatory Commission (FERC)	- Federal agency responsible for enforcement of electric sector reliability requirements, including oversight of the ERO (NERC)
North American Electric Reliability Corporation (NERC)	- Designated as the Electric Reliability Organization (ERO) by FERC; responsible for developing, assessing and enforcing reliability standards
Regional Reliability Organizations (RROs)	- Members of the NERC that ensure regional operations are reliable, adequate and secure. Includes: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First (RF), SERC, Southwest Power Pool (SPP), Texas Reliability Entity (TRE), and Western Electric Coordinating Council (WECC)
Grid and System Operators, and Balancing Authorities	- Responsible for the reliability functions in specific geographic areas. In addition to many electric utilities, there are other organizations serving this function in wide geographic areas, including Regional Transmission Organizations (the New York System Operator (NYISO), PJM Interconnection, New England Independent System Operator (ISONE), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), and Electric Reliability Council of Texas (ERCOT)

Those responsible range from: the federal regulators at the FERC, which has statutory authority relating to system reliability; to NERC, the nation's "Electric Reliability Organization" (ERO), authorized by FERC to set reliability standards for grid operators, utilities and other power companies; to Regional Reliability Organizations (RRO) which ensure that the system is reliable, adequate and secure within the geographic footprint for which they're responsible; to grid operators (also known as "balancing authorities" or "system operators") with the operational responsibility in smaller areas.[28] Each

go down can cause a rapid loss of demand with the immediate need to address that big imbalance on the overall system in order to avoid a bigger problem affecting many other areas of the grid. Similarly, high penetrations of distributed resources (e.g., rooftop solar panels on customers' premises) connected to the local distribution system are emerging as a reason to increase the BPS grid operator's "visibility" into what is happening at the distribution system level because of the interrelationships between the two systems. In fact, several areas with significant current or expected installation of distributed resources (e.g., Hawaii, California) have begun to evaluate potential system-wide challenges associated with such developments.

[28] NERC's Glossary of Terms formally defines the various entities, along with various terminologies that described their responsibilities. NERC, "Glossary of Terms Used in NERC Reliability Standards," January 29, 2015, available: http://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf

one has different responsibilities, as shown in Table 8.

These entities monitor system reliability using time-tested, well-developed industry analytic tools. For longer-term assessments, the standard methods take into consideration a vast array of potential future infrastructure scenarios and system operational contingencies (e.g., sudden loss of generation, transmission or load). Annually and seasonally, system operators and reliability planners conduct reliability assessments to evaluate system changes, flag areas of concern that need to be addressed within different time frames, and identify plans to address any reliability concerns that may arise over the planning period. In addition, special assessments are periodically carried out in response to any industry or policy changes that have the potential to affect system reliability.

Thus it should not be surprising that EPA's proposed Clean Power Plan is being (and will continue to be) evaluated for potential reliability impacts in future years. We have seen such reliability evaluations exercised regularly over decades in the face of other major industry changes, as noted previously.[29] In every case, the prospect of change has led to reliability assessments and the waving of cautionary flags to call attention to the new challenges ahead.

How could electric system reliability be affected by the Clean Power Plan?

The Clean Power Plan will not lead to more cars hitting distribution poles, nor will it affect the frequency, location, or severity of storms that lead to local outages. The more relevant questions are how controls on power plant CO_2 emissions will affect power system components and operations. As highlighted in Section III (which summarizes stakeholder concerns around the Clean Power Plan's potential impacts on system reliability), concerns primarily relate to impacts these pollution controls will have on availability of existing power plants. Will plants

[29] There are many examples where changes in conditions have led to questions about whether the electric industry (and its supply chains) could respond in a sufficiently timely and effective way to avoid reliability problems. This occurred, for example, with: (1) prior EPA and state regulations governing human health and environmental impacts, including the CAA Title IV sulfur dioxide cap-and-trade program contained in the 1990s; the changes in National Ambient Air Quality Standards (NAAQS) and Clean Water Act (CWA) requirements; the more recent CSAPR and MATS regulations; and the proposals under 316(b) of the CWA. (2) Changes to the structure of the electric industry over the past several decades, involving major changes in the regulation of and the incentives for investment and operation; transfers of ownership and management of existing generation and transmission system elements; and the formation of RTOs and associated wholesale markets for energy, capacity and ancillary services. (3) Fundamental shifts in the economics of generating power from coal or from natural gas, driven initially by changes in technology costs (e.g., large-scale steam generators versus combined-cycle technologies) and more recently by the emergence of low-priced domestic shale gas resources; the growing strain in some regions on the capacity of interstate natural gas delivery and storage systems to meet combined demand from heating and electricity generation uses during peak winter conditions; and different business practices, and operational protocols and standards in two industries (the natural gas industry and the electric industry) that might need to be better aligned as the two industries become more interdependent. (4) The ongoing displacement of traditional generation resources by grid-connected and customer-sited variable renewable resources, in some cases dramatically changing the shape of net load that must be followed by system operators. (5) Questions about the ability of some wholesale electricity markets to provide sufficient financial incentives for suppliers to continue to operate and/or to enter the market.

retire and, if so, which ones and when? Which new ones will be added, over what time period? Will gas pipelines and other fuel-delivery infrastructure be in place in time to fuel a power system that depends more upon natural gas? Will the electric transmission system be capable of moving power generated in new locations relative to customer demand?

Insights and answers to these various questions fall into two basic categories, differentiated by time scales. One focuses on long-term planning considerations, and is called "resource adequacy": Will there be enough (adequate) resources in place when system operators need to manage the system to meet demand in the future? The other focuses on short-term operations, and is called "system security": Will the operators be able to run the system in real time in a secure way to keep the system in balance, with all that that entails technically?[30]

Resource Adequacy

First, the interconnected electric grid must have resource adequacy – that is, there must be sufficient electric supply to meet electric demand at the time of annual peak consumption, taking into account the expectation that some parts of the system will not be able to operate for one reason or another. The system must have some additional quantity of capacity above the annual peak load value (the reserve margin) to cover the possibility that in highest-demand hours some resources may be out of service due to planned or unplanned outages.[31] In some regions and sub-regions (or "zones"), constraints on the ability of the transmission system to move power from one location to another mean that some portion of the demand within the zone must be met by generating resources within that same zone.

Ensuring resource adequacy is generally accomplished through two steps. First, the expected system peak demand and energy requirements over a long-term period (e.g., ten years) are established through a comprehensive forecasting effort. Forecasting processes for this purpose use well-established economic and industry modeling tools and data, are conducted frequently, and typically involve input by utilities, grid operators, public officials, consumer advocates, and

[30] The U.S. Energy Information Administration (EIA) defines electric system reliability as the "degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired. Reliability encompasses two concepts, adequacy and security. Adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected electrical demand plus reserves for contingencies. Security implies that the system will remain intact operationally (i.e., will have sufficient available operating capacity) even after outages or other equipment failure. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service." U.S. EIA, "Glossary," available at http://www.eia.gov/tools/glossary/index.cfm?id=E.

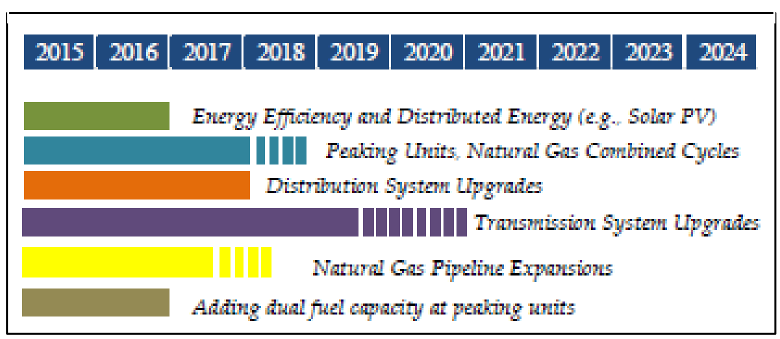
[31] Reserve margins are generally in the range of 10 to 20 percent of system peak load. The actual reserve margin varies from region to region as a function of many factors (e.g., the mix and expected performance of assets on the system, operational and emergency procedures, the availability of demand response/load curtailment, and contributions that may come from neighboring regions).

many other market participants and stakeholders. This step occurs in both wholesale energy markets and through integrated resource planning conducted by electric utilities.

Second, to the extent that identified long-term needs exceed resources expected to be on the system (due, for example, to growth in demand over time, and/or the retirement of existing resources), the deficit is met through the addition of new infrastructure (power plants or transmission lines) and/or demand resources (such as energy efficiency or demand-response measures). The ways in which new resources are added varies around the country, depending on the structure of the electric industry and the regulatory approach in place in a given state, along with other aspects of the market (including FERC-regulated RTOs in many regions). In wholesale market regions like PJM and NYISO, identified needs are met through market structures designed to provide financial incentives for investment in new capacity. In other regions (like most of the West), vertically integrated utilities, cooperatives and municipal electric companies add needed capacity by proposing and building their own project and/or through soliciting offers from other competitive suppliers. In any event, the overall resource need is forecasted (and, if relevant, a local/zonal requirement is further identified), and some combination of regulated and/or market process brings forth proposals to satisfy the need.

These processes are designed to accommodate the lead times necessary to bring a new project or resource into operation. They typically involve sufficient advance notification of need to allow for: (1) initial development stages and associated studies around project feasibility, interconnection, etc.; (2) administration of the markets or competitive procurement processes (and regulatory approvals of them); (3) zoning, permitting, and siting approvals for specific facility projects; (4) construction of the power plant and associated infrastructure (e.g., transmission interconnection/upgrades and – if needed – fuel delivery such as natural gas pipeline connections). Lead times for implementing peaking generating units and demand-side actions (e.g., programs leading to installation of energy efficiency measures; equipping buildings with automated capability to control demand when signaled to do so by the system operator; adding solar PV panels) are much shorter than those for large power plants and transmission upgrades. Figure 2 provides a conceptual depiction of lead times for planning, developing and installing

Figure 2
Typical Lead Times for Different Electric Resources



Source: Analysis Group

different types of infrastructure to support electric resource options.

The processes outlined above rarely occur in a sequential fashion.[32] Ten-year assessments take into account time periods that extend well beyond the number of years it typically takes to develop, permit, finance, and construct a new power plant.[33] As one developer is starting to scope out where to site a new power plant in anticipation of hoping to get approvals and enter the market four years in the future, another already has its approvals and has commenced construction. Installation of demand-response measures take much shorter time periods altogether. Many steps occur concurrently across many different types of resources that are being planned and put in place to meet resource adequacy requirements.

In practice, there are exceptionally few instances where industry has failed to provide for resource adequacy, where – due to a lack of installed capacity – the grid operator had to implement emergency protocols (such as lowering voltage (sometimes known as rolling brownouts) or curtailing service to customers (sometimes known as rolling blackouts)).[34] Although there have been rare occasions where a relatively near-term resource adequacy problem has been identified, regulators, market participants, grid operators, customers and reliability organizations have taken the steps needed to assure that the lights stayed on. There are well-known examples from around the country where the industry (including its regulators) did what was necessary to keep power flowing to consumers.[35] In large part, this track record

---

[32] For example, often initial market development of a new generating resource – e.g., site identification and control, technology selection, fuel and transmission infrastructure studies, fatal flaw analyses, even some initial siting and permitting efforts – happen in advance of or concurrent with resource need specification or market/utility procurement. Similarly, engineering, construction, and fuel contracts may be established (on a contingent basis) prior to final resource selection or final regulatory approval. Successful resource development teams effectively manage the flow of steps needed to take a new power plant from concept to operation so as to balance the stages of investment risk against the process of procurement and approval.

[33] Typically, lead times for a new natural gas power plant involve 2 years for development and permitting and another 2 years for construction. A peaking unit typically takes less time: from 2 to 3 years. Demand-response and other distributed energy resources can be brought to market in 1 to 2 years. Some generating additions may further require transmission or distribution system upgrades. These can range in time from as little as 2 to 3 years for local distribution upgrades to 5 to 6 years or longer for more extensive transmission system upgrades, but such permitting and construction activities are carried out coincident with power plant permitting and construction. Lead and development times are in part, flexible, depending on the system need and critically, it is possible to move faster when needed. For example, following the California Energy Crisis in the early 2000's, the state added thousands of MWs of new generation using a set of emergency 21-day, 4-month, and 6-month citing procedures. These emergency responses helped establish a set of best practice siting procedures that can be used by other states in similar situations. Susan F. Tierney and Paul J. Hibbard, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," Hewlett Foundation Energy Series, February 2002.

[34] A notable exception is the well-known California electricity crisis of 2000-2001, which resulted from a combination of actions (including market manipulation through actions in the electric and natural gas markets, as well as caps on retail electricity prices). To our knowledge, there has never been a resource adequacy event (e.g., a brownout or blackout) due to implementation of an environmental regulation.

[35] Examples include:

- ERCOT's slim reserve margins in recent summers, including for example, in 2012, when nearly 2,000 MW of mothballed capacity was returned to service. Commissioner Anderson Jr., Public Utilities Commission of Texas, "Resource Adequacy in reflects the existence of the many resource-adequacy processes outlined above, the presence of multiple early warning systems, the ability of policy makers to take action to address challenges when urgent action is needed,[36] and a strong mission orientation of the industry and its regulators.[37]

System Security

Even assuming that these resource adequacy processes end up ensuring there are enough megawatts of capacity in place when needed to meet aggregate load requirements, actual

---

ERCOT," Update #4, January 30, 2013. Available: https://www.puc.texas.gov/agency/about/commissioners/anderson/pp/analysis_ercot_capacity_reserve_margin_013013.pdf.

- Reliability must run (RMR) contracts to keep plants operating, for example:
  - The retention of operations of the Potomac Generating Station until completion of the Pepco transmission lines; see, Paul J. Hibbard, Pavel G. Darling, and Susan F. Tierney, "Potomac River Generating Station: Update on Reliability and Environmental Considerations," July 19, 2011);
  - A delay in Exelon's proposed retirement of the Eddystone and Cromby generating stations in Pennsylvania after PJM determined that in the absence of transmission upgrades, retirements of those units would lead to violations of security standards, with a reliability must run agreement between PJM and Exelon and state air regulators so that the plant could remain on line pending those transmission upgrades, but with limits on the units' dispatch to only those times when the units were needed for operational reliability purposes. Prepared Testimony of Kathleen L. Barrón, Vice President of Federal Regulatory Affairs and Policy, Exelon Corporation, before the FERC, Reliability Technical Conference Docket No. AD12-1-000 (etc.), November 11, 2011.
- Construction of peaking units on a fast-track basis by the New York Power Authority: "We increased our generating capacity by about 450 megawatts during summer 2001 when we began operating small, clean natural gas-powered generating plants at six sites in New York City and one on Long Island. We had launched a crash program in late August 2000 to install these PowerNow! plants in response to warnings from officials in the public and private sectors that the New York City metropolitan area could face power shortages in the summer of 2001. Similar warnings were repeated throughout the 10 months it took to obtain, site, design and install the units—a process that normally would require more than two years." New York Power Authority, "Small Clean Power Plants," Available: http://www.nypa.gov/facilities/powernow.htm.
- Requests by ISO-NE for demand-response resources in Connecticut on a fast-track basis: "On December 1, 2003, ISO New England Inc. (ISO-NE) issued a Request for Proposals (RFP) soliciting up to 300 MW of temporary supply and demand resources for Southwest Connecticut (SWCT) for the period 2004 to 2008. The purpose for acquiring these resources was to improve the electric system reliability in SWCT through the summer of 2007, when the 345 kV transmission loop is planned for completion." J.E. Platts, ISO-NE, "Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability, 2004-2008," October 4, 2004, page iii.
- New York State's contingency planning efforts (including consideration of new transmission projects) to prepare for a possible shutdown of the Indian Point nuclear plant, shutdown as early as 2018, depending on the outcome of its re-licensing with NRC. See the New York Department of Public Service Commission Case No. 12-E-0503, "Proceeding on Motion to Review Generation Retirement Contingency Plans." Available: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=12-e-0503&submit=Search+by+Case+Number

[36] Susan F. Tierney, and Paul J. Hibbard, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," Hewlett Foundation Energy Series, February 2002.

[37] For example, FERC/EPA processes under the MATS regulation introduced a Reliability Safety Valve and related procedures to ensure that identified reliability challenges could be addressed, while allowing some flexibility with the eventual MATS timeline. As discussed below, the ISO/RTO council has proposed a similar reliability safety valve for the Clean Power Plan and the EPA has also acknowledged potential reliability concerns in its most recent Notice of Data Availability memorandum.

'delivered' reliability also depends on making sure that the system operates in real time with high technical integrity.

System reliability is affected in real time by several things:

- The mix of attributes of the resources on the system – their location, their fuel source, and the operating characteristics of the supply and demand resources;
- The variations in system conditions (e.g., building lights turned on, or a power plant tripping off line unexpectedly, or sudden storm-related outages, or shifts in windiness) that change on a second-to-second, minute-to-minute, hour-to-hour, and day-to-day basis; and
- The system operator's practices and procedures for managing the changing conditions on the system at all times and in all places under that operator's responsibility, to assure that the system stays in balance.

System security describes the ability of the system to meet ever changing system conditions, and to do so with enough redundancy in operational capabilities to manage and recover from a variety of potential system events – or "contingencies" – such as sudden and unexpected loss of generation, transmission, or load.[38] System planners and operator must ensure that the mix of resources on the system is capable of responding in real time to normal load changes and contingency events. This is needed to avoid the catastrophic wide-area failure of the bulk power system – such as a cascading outage covering one or more regions – that can come from unacceptable variations in system voltage and frequency. Blackouts can damage electrical equipment on the grid and on customers' premises, and create wide-ranging safety and health impacts.

To assure system security, the system as a whole must have certain attributes allowing it to provide "essential reliability services," as summarized in Table 9. These include two functional categories:

- *Voltage support*, meaning the ability of system resources to maintain real power across the transmission grid, through the use of reactive power sources such as generators connected to the system, capacitors, reactors, etc. Voltage on the system must be

[38] NERC describes certain features of the bulk power system needed to meet system security requirements – e.g., voltage control, frequency control – as Essential Reliability Services, or ERS. NERC Essential Reliability Services Report.

maintained within an acceptable voltage bandwidth in normal operations and following a contingency on the system.[39]

- *Frequency Management*, meaning the ability of the system to maintain a system frequency within a technical tolerance at all times.[40] Frequency is a function of the match between generation output and load on the system, and requires constant balancing, or following of load by resources that can increase and decrease output instantaneously.

Importantly, system security, or operational reliability, is not a "yes" or "no" condition. To maintain it, system operators use a combination of strategies, tools, procedures, practices, and resources to keep the entire system in balance even as conditions change on a moment to moment basis.[41] The difficulty of this task largely results from several things. First, the

[39] Voltage support is local in nature, can change rapidly, and depends in part on the type and location of generators connected to the transmission system. Typically, voltage control is maintained by system planners and operators. Acceptable power factors for voltage support are maintained, in part, through the use of reactive power devices (or power factor control) that inject or absorb reactive power from the bulk power system. Reactive power can be provided by synchronous thermal generators and through capacitors and other devices, as well as by 'adequately designed' variable energy resources (including wind and solar) and storage technology. Voltage disturbance performance is the ability to maintain voltage support and voltage control after a disturbance event. NERC Essential Reliability Services Report, pages 1, 10-11.

[40] Frequency must typically be maintained within tens of mHz of a 60 Hz target. Higher frequencies indicate greater supply, while lower frequencies typically indicate greater demand. Frequency management includes: (1) Operating reserves, which are used to balance minute to minute differences in load and demand, load following capabilities to respond to intra- and inter-hour changes in load fluctuations, and reserves, which are used to restore system synchronization following generator or transmission outages; (2) Active Power Control, including ramping capability to quickly bring generators online in response to operator needs, often in ten minutes or less; (3) Inertia, or stored rotating energy that is used to arrest declines in frequency following unexpected losses. Historically, inertia has been supplied by large coal-fired generators, although NERC notes that new 'synthetic' inertia is available through the operation of variable energy resources supported by energy storage devices; and (4) Frequency Distribution Performance, which similar to voltage distribution performance, is the ability to maintain operations during and after an unplanned disturbance. NERC Essential Reliability Services Report, pages 3-5, 8-9.

[41] System operators manage voltage and frequency as load changes over time, and in response to contingency events, through the posturing and management of the resources on the system across several time scales:

- On a second-by-second basis through automatic generation control (AGC) systems on resources that will automatically adjust generation up or down in response to system frequency signals.
- On the time scale of minutes through tens of minutes through accessing "spinning reserves," including operating resources with the ability to ramp output up or down quickly, and resources that can connect to the system within several minutes.
- On the timescale of tens of minutes through accessing longer-term reserve resources that can turn on and connect to the system in less than an hour (typically on the order of 15 to 30 minutes).
- On the time scale of hours or days by committing sufficient operating and reserve resources to manage *expected* swings in net system load (that is, system load net of variable resource output). Note that load varies in relatively 'normal' ways over the course of the days, weeks, and months, and is predictable with a relatively high degree of accuracy by system operators. This allows for the commitment and availability of enough system resources to meet reliability objectives. However, the proliferation of distribution-level, behind-the-meter (BTM) generation with variable output (e.g., distributed wind and solar PV) complicates the forecasting of "net load" visible to system operators – that is, the normal variation in load net of variable BTM output that comes and goes with the sun and wind.
- On an as-needed basis for voltage control by adjusting reactive power injected into or absorbed from the system by on-line generators, capacitors, reactors, and system var compensators.

Source: NERC Essential Reliability Services Report, generally.

operator has, in effect, a particular set of assets on the system at any time, which reflects the operational attributes of the various resources on the system at that time. These include things like: power plants with different operating profiles (e.g., start-up time, limits on output under different temperature conditions, availability to fuel supply); transmission systems that allow or limit power flows in various directions; 'smart' controls and communications devices that allow (or not) visibility into and/or management of power flows; demand response; storage systems; and so forth.

Table 9
System Security Needs and "Essential Reliability Services"

Services	Components		Description	Consequences of Failure
Voltage Support	*Voltage Control*		Support system load; maintain transmission system in a secure and stable range	· Loss of Load · Equipment Failure · Cascading Losses
	Voltage Disturbance Performance		Ability to maintain voltage support after a disturbance	
Frequency Management	*Operating Reserves*	Regulation	Minute-to-minute differences between load and resources	· Loss of Generation · Load Shedding · Interconnection Islanding · Overload Transmission Facilities · Damage Equipment and lead to Power System Collapse
		Load Following	Intra- and inter-hour load fluctuations	
		Reserves	Includes Spinning, Non-Spinning, and Supplemental; Used for synchronization and respond to generator or transmission outages in 10 min or greater time frames	
	Inertia		Stored rotating energy; Used to arrest decline in frequency following unexpected losses	
	Frequency Distribution Performance		Ability of a plant to stay operational during disturbances and restore frequency to BPS	
	Active Power Control	Frequency Control	Real-time balance between supply and demand	
		Ramping (Curtailment) Capability	Ability to increase/decrease active power, in response to operator needs. Measured in MW/min basis	

Notes and Sources:
[1] Adapted from NERC (2014) "Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability".
[2] NERC (2014) notes that these Essential Reliability Services are functionally equivalent to the Interconnected Operations Service (IOS) definitions, with Voltage Support covering Reactive Power Supply from Generation Sources and Frequency Support covering Frequency Response, Regulation, Load Following, and Contingency Reserves.
[3] NERC notes that many of these ESRs are already defined as ancillary services in the OATT of many system operators. Ancillary services are "those services necessary to support the transmission of electric power form seller to purchaser", considering reliabilty needs. Therefore, NERC considers ancillary services to be a subset of ESRs.

Second, the operator must maintain frequency and voltage on the system at all times. This means, for example, starting up plants as backup resources ("reserves") to quickly replace another plant that trips off line or dips in its output (e.g., due to changes in wind conditions or power plant failure), or adjusting power output up and down with little notice to meet swings in load.

Third, the operator maintains and draws on a diverse set of operational procedures to manage system performance – such as committing or "posturing" resources that may be needed, allowing minor variations in system voltage, calling on resources from neighboring regions, disconnecting variable generation, signaling to 'demand-response' providers to curtail their loads within short periods of time, and other procedures (including, as a last resort, isolated involuntary disconnection of load – or "rolling blackouts").

Reliability is by nature a technology-neutral concept. That said, not all of a system's resources are equal when it comes to the attributes they provide to system operators to manage system security. Historically, power systems' needs for voltage support, inertia, frequency control, and contingency-response capability have been met through operator actions in conjunction with their commitment of the types of technologies on the system: traditional thermal steam units (e.g., coal, nuclear, oil plants, natural gas and combined heat and power units) providing baseload service around the clock; cycling and load-following technologies (e.g., combined cycle plants operating on natural gas); quick-start fossil-fired peaking plants; and dispatchable hydro power supplies.

As the technologies on the system change – which is happening to different extents in different regions as a result of various forces, with or without the Clean Power Plan (as described above in Section I) – steps are being taken to ensure that the suite of essential reliability services is available to supply the frequency/voltage control and contingency-reserve needs of the system. NERC has characterized the challenge as one of filling gaps in services as they arise or widen over time.

Notably, system planners across the country are dealing constantly – and so far successfully – with the new and emerging reliability challenges from changing technology mixes. For example, the CAISO and California electric utilities have identified the need to add greater ramping capability to handle an increased variability in intra-day loads introduced from increasing amounts of 'variable energy resources' (VERs) necessary to meet increasingly higher renewable portfolio standards.[42] In general, load following is typically accomplished through the dispatch of fast-ramping combustion turbines and natural gas combined cycle (NGCC), although load following can also be met through well-designed and cost-effective storage, optimized energy efficiency programs, demand response, and devices (such as smart inverters) being added to wind farms.

[42] California is on track to meet its renewables portfolio standard target, such that by 2020, 33 percent of its total energy comes from renewable resources. The state is considering whether to adopt a 50-percent goal by 2030. Behind-the-meter solar and wind supplies are projected to significantly decrease net load during the middle of the day, while leaving significant shoulder peaks in the morning and evening, resulting in what is commonly called the "duck curve." A recent analysis found that this will require a significant increase in fast ramping, flexible dispatchable generation resources (along with other technologies, including storage). See Energy+Environmental Economics (E3), "Investigating a Higher Renewables Portfolio Standard in California," January 2014.

III. What Concerns are Commenters Raising About Reliability Issues Associated with EPA's Clean Power Plan?

Summary of comments

To date, the EPA has received more than 3 million comments on the proposed Clean Power Plan. Many comments have raised concerns about electric system reliability. These comments have come from a wide range of stakeholders, including: owners of affected power plants (including vertically integrated utilities, merchant generators, municipal electric utilities, cooperatives); state officials, including public utility commissions, air pollution regulators, energy offices, as well as governors, attorneys general, and consumer advocate offices, and associations representing these various groups of public officials; system operators, regional reliability organizations; trade associations with business, public health, environmental, fossil-fuel supply and delivery organizations; members of the public; and others.[43]

The many comments received on reliability issues reflect the importance of thinking clearly about the potential impacts of the Clean Power Plan on system reliability. We summarize the types of reliability-related comments in Table 10, below, and provide more information about these public comments in the Appendix. Notably, EPA has made it clear that system reliability needs to be maintained as the Clean Power Plan is finalized and implemented.[44]

[43] Among the latter include various electric industry organizations (e.g., the Edison Electric Institute; the APPA; the National Rule Electric Cooperative Association; the Electric Power Supply Organization; the Clean Energy Group); business associations (e.g., the Chamber of Commerce); gas industry organizations (e.g., the Interstate Natural Gas Association (INGAA)); coal-industry groups (e.g., the Coal Utilization Research Council); non-energy trade groups (e.g., Water Associations such as the American Water Works Association, National Association of Water Companies and the National Association of Clean Water Agencies), and environmental organizations (e.g. Natural Resources Defense Council and Environmental Defense Fund); NERC; various individual RTOs (MISO, PJM, NYISO); FERC Commissioner Philip Moeller; Senator Dan Coats and 22 other senators. This is not intended to be a comprehensive or exhaustive list of comments or commenters, but rather represent the broad cross-section of types of organizations with an interest in Clean Power Plan reliability issues. Regulations.gov Docket Folder Summary, Docket No. EPA-HQ-OAR-2013-0602, "Standards of Performance for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units," available at http://www.regulations.gov/#!docketDetail;rpp=100;so=DESC;sb=docId;po=0;D=EPA-HQ-OAR-2013-0602.

[44] For example, see both the Proposed Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Federal Register, Vol. 79, No. 117, June 18, 2014. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf, and the Technical Support Document: Resource Adequacy and Reliability Analysis. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-resource-adequacy-and-reliability-analysis

Table 10
Summary of Reliability Concerns Raised in Public Comments and Which Need to be Addressed as the EPA's Proposed Clean Power Plan is Implemented

Summary of Comments Submitted on Reliability Issues Related to the EPA Clean Power Plan		
Category	**Description**	**Potential Reliability Considerations – Which Need to be Addressed**
Resource Adequacy	Retirements of baseload power plants are presenting on-going challenges in some regions	May tighten planning reserve margins in some regions and require timely replacement of capacity on a 1-to-1 basis
		Requires additional transmission planning and analyses, with transmission solutions typically having longer lead times (~10 years) than generation additions
Resource Mix and Operational Security	Retirement of coal-fired capacity and restrictions on output at coal plants, combined with greater use of gas-fired capacity, will result in less fuel diversity in various regions	Some coal units will/may be cycled more frequently, ending up with lower overall capacity factors and adversely impacting relevant heat rates (and emissions per MWh)
		Operating gas plants at higher output will depend upon having adequate gas delivery capability, including firm supply and delivery contracts
		Increased reliance on variable and non-dispatchable resources (like wind and solar) will mean the need for greater quantities of operating reserves and ramping capability
		Loss of baseload generation requires additional voltage and frequency Support, including Inertia
Planning and Regulatory Coordination	The interim goals established in the Clean Power Plan do not provide adequate time for planning and development of adequate resources, for state and regional coordination, or for market solutions	Lead times for new transmission and power plants (including planning, siting, permitting, and construction time lines) extend beyond 2020 and the interim deadlines)
		Successful resolution of various gas-electric coordination issues will be needed to support greater reliance on natural gas in many regions
		RTO/ISO rules and practices regarding security-constrained economic dispatch may need to be reviewed and/or updated, depending upon how states design their plans to incorporate emissions controls
		Greater reliance on demand response and energy efficiency may require new rules and forecasting capabilities in wholesale energy and capacity markets
		Allocation (or reassignment) of transmission rights may be needed to accommodate changing power flows following power plant retirements or to accommodate greater reliance on underutilized gas-fired capacity and/or renewable resources.
Market Impacts and Market Responses	Uncertainty surrounding final regulations and state plans make it hard for markets to respond with concrete proposals in timely fashion	Uncertainty surrounding the regulatory treatment of new gas-fired combined cycles (under 111(b)) may chill development.
		Increased reliance on gas-fired power plants may depend upon new investment in pipeline capacity, with need for new mechanisms to support long-term commitments in some regions (e.g., organized markets)
		Increased reliance on natural gas may accelerate retirements of nuclear units prior to the end of their operating licenses.
		Reliability must-run contracts may be needed to retain some units needed for reliability, but with potential adverse impacts on wholesale market efficiency
		Uncertainty surrounding how states will plan for ensuring new capacity additions in regional organized markets, in light of buyer-side mitigation and other federal wholesale market rules

Many observers' concerns that the Clean Power Plan could jeopardize *resource adequacy* are tied primarily to questions around timing: Does the sequence of steps implied by EPA's proposal – starting with the June 2014 proposal, then taking into account the timing of EPA's final rule, the development of State Plans, the approval of plans by the EPA, and then through compliance decisions and actions by owners of affected power plants – allow sufficient time for everything that needs to be done by states, reliability planners, grid operators, planning and procurement processes, market responses, and so forth to ensure resource adequacy? Or, where that is not assured, do the final EPA and state compliance provisions and administrative procedures allow sufficient flexibility to ensure proper administration of Clean Power Plan without jeopardizing resource adequacy?

Concerns voiced about whether Clean Power Plan implementation could jeopardize *system security* are tied primarily to anxiety over how and when state compliance activity will alter the diversity of resources on the system, and thus the mix of resource capabilities needed to meet system security requirements. In particular, will the economic signals and compliance obligations provided through state implementation of the Clean Power Plan cause the retirement of resources that are needed for system security, and/or will replacement capacity provide the needed operational capabilities? If a significant portion of existing coal-fired capacity retires and is replaced (in part) by gas-fired capacity, will regional interstate pipeline systems be robust enough to ensure reliable delivery of fuel in all hours of the year? If state compliance activities significantly increase the proliferation of grid- and distribution-level variable resources, how much more difficult will it be for system operators to manage the variability in net load on a real-time basis? Or, where this is not assured, do the final EPA and state compliance provisions and administrative procedures allow sufficient flexibility to ensure proper administration of Clean Power Plan without jeopardizing system security concerns?

Other commenters portray the readiness of the industry to step up with solutions to these reliability issues. For example, INGAA described the capability of the natural gas pipeline industry to add new infrastructure.[45] Calpine stated its readiness (along with other market participants) to add new gas-fired generation (and to offer under-utilized capacity already existing on the system).[46] The Clean Energy Group provided suggestions about how the design of policies supporting flexibility and market-based approaches can substantially mitigate reliability concerns.[47] State energy offices (through their national association (NASEO)) noted the ability of a wide variety of well-tested energy efficiency measures (beyond utility-provided programs) to avoid CO_2 emissions from power plant operations.[48] The National Association of Regulatory Commissioners (NARUC) pointed to the ability to reap cost-effective savings in the

[45] Comments of INGAA, filed December 1, 2014.

[46] Comments of Calpine Corporation, filed November 26, 2014.

[47] Comments of the Clean Energy Group (CEG), filed December 1, 2014.

[48] Comments of the National Association of State Energy Officials (NASEO), filed December 1, 2014.

electricity used for water treatment and delivery by introducing measures on the water utility system – thus affording water savings and avoiding CO_2 emissions on the power system.[49]

We also point out many ways to address the reliability issues raised in comments in Section IV of our report, with our suggestions organized around the different entities with some direct or indirect role to play in system reliability.

Reliability safety value concept

The ISO/RTO Council (IRC) has proposed that EPA include a "Reliability Safety Valve" provision as part of the final rule, to help with resolve multi-state issues that may arise due to the Proposed Rule and impact grid reliability.[50] In the view of the IRC, a Reliability Safety Value would provide a regulated and reviewed backstop solution with a defined process for modifying State Plans to ensure reliability against unforeseen issues. As part of this process, the IRC has recommended that the EPA include a specific requirement in the final rule that State Plans must include a detailed reliability assessment. By requiring reliability assessments ahead of final plans, according to the IRC, the Reliability Safety Valve would only be used in situations that could not be addressed ahead of time and that arise solely from dynamic, unplanned changes in the grid. As proposed by the IRC, a Reliability Safety Value would allow relief from compliance schedules if specific units are deemed necessary for reliability considerations.[51] The Reliability Safety Value has been supported by numerous organizations and RTOs, who point out that the concept has been successfully implemented as part of the MATS compliance policy.

We note – as an important element in considering the particular Reliability Safety Valve proposed by the IRC – that there are key differences between the regulatory frameworks of Clean Power Plan and the MATS rule. In particular, the latter assigns emissions-reductions targets on each affected fossil-fuel generating unit, and does not allow any emission averaging across generating stations or across time. As we noted previously in this report, there is much more flexibility in the design of the Clean Power Plan.[52] In particular, the opportunity for states

[49] Comments of the National Association of Regulatory Utility Commissioners (NARUC), filed November 19, 2014.

[50] For example, see comments filed by the ISO/RTO Council (IRC), December 1, 2014.

[51] This process is analogous to RMR contracts that are often available in organized ISO/RTO markets. These contracts provide for time-limited, out-of-market payments to generators that have provided notification of retirement but are necessary for reliability reasons (e.g., local voltage support). Once alternative resources (transmission or generation) solving the reliability need are in place, the RMR contracts cease and the units may retire. By way of example, the IRC suggests that the Reliability Safety Value and a mandatory reliability assessment could help identify reliability issues arising from an individual State Plan, such as a state requirement for reduced utilization at a fossil unit needed for transmission security and voltage support on a transmission network that crosses a state line. ISO/RTC Comments, filed December 1, 2014.

[52] EPA is relying on a portion of the Clean Air Act– Section 111(d) – in its Clean Power Plan. "Section 111(d)'s regulatory framework creates an entirely different and potentially much wider set of compliance and implementation options compared to

to rely upon market-based mechanisms that allow emission trading across power plants within states and across wide regions is a compelling basis for thinking differently about the need for a reliability safety value in this instance. The wider the region in which emission trading might occur, the less likely that reliability issues will be introduced by the Clean Power Plan.

NERC's initial reliability assessment of the Clean Power Plan

NERC published its own "Initial Reliability Review" of the Proposed Rule in November 2014.[53] NERC flagged a number of "significant reliability challenge[s], given the constrained time period for implementation" and that "Essential Reliability Services may be strained by the proposed [Clean Power Plan]."[54] NERC notes that the primary purpose of the paper was to "provide the foundation for the range of reliability analyses" that will be required for stakeholders to work together. Notably, NERC recommended that coordinated regional and multi-regional planning and analysis should start immediately to identify specific areas of concern and that the EPA should consider a more timely approach to resolving any known reliability concerns.

NERC noted that the accelerated retirement of fossil units will stress already declining reserve margins, and that time will be a major constraint, particularly for facility planning, permitting, and construction. NERC identifies transmission upgrades as potentially being needed to successfully integrate variable energy resources anticipated as part of various states' plans, as well as to support reliability concerns regarding voltage and frequency support associated with extensive re-dispatch of NGCC. NERC also suggested that pipeline capacity constraints will

---

other recent federal regulatory initiatives applicable to the electric industry.… In the recent MATS rule, for example, EPA set uniform national standards to reduce emissions from different categories of existing coal- and oil-fired power plants. No trading or averaging is allowed across different generating stations. There is no possibility of purchasing credits resulting from over-compliance at other sources, or to credit emissions reductions resulting from end-use efficiency or zero-carbon energy sources. By contrast with MATS, Section 111(d) inherently allows greater opportunities for different pathways to compliance… And in its [State Plan], each state will have flexibility to propose its own preferred actions to accomplish the targeted reductions, as long as the plan provides reductions across the facilities in the state that are at least as effective as EPA's approach. This language "supports the use of market-based mechanisms" and other alternatives in ways that are not possible under the statutory language governing MATs, which required each affected generating station to have emissions at or below the allowed emissions rates. If a state has concerns about the reliability implications of compliance with EPA guidance, the state can take that fact into account as it designs its SIP and its schedule/timetable for individual units' compliance so long as the overall emission reduction required by the guideline has a firm deadline and is achieved. For example, a state could propose plan elements that enable early action/compliance at some Section 111(d) generating units in exchange for allowing more time for others, or that allow for deeper reductions at one unit in exchange for lighter reductions at another." Source: Susan F. Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 2014, pages 3-4.

[53] NERC has stated that its November report, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review," November 2014 (Hereinafter referred to as "NERC CPP IRR") is the first in a series of reliability assessments that NERC plans to conduct. NERC says it plans to release two additional studies in 2015 that will include a detailed evaluation of generation and transmission adequacy and a preliminary assessment of state SIPs.

[54] NERC CPP IRR, page 2.

exacerbate the strain on essential reliability services from relying more heavily on gas. While a full review of the NERC study is beyond the scope of this paper, we note again that these issues have been emerging in markets for a number of years, well before the introduction of the Clean Power Plan. Indeed, NERC covered these "emerging trends" in California, Hawaii, ERCOT, and other regions in its October primer on "Essential Reliability Services."

Many comments in turn, have cited and expanded on the NERC Review. While reliability has been a common theme of these comments, for the most part the NERC report and the public's comments on the Clean Power Plan do not point to specific, modeled reliability problems that have been identified at known points on the bulk power system. Rather, both the report and the comments focus on generalized concerns about potential reliability issues that may arise due to the operational challenge of meeting both the interim and final-goal targets, generally assuming little in the way of the compliance flexibility built into the proposed rule and available to states. While these are valid concerns, it is critical to recognize the numerous strategies, policies, markets and organizations in place that have successfully dealt with these similar operational challenges in the past, and will going forward, as we discuss further below.

Moreover, the Clean Power Plan proposed rule, like all proposed EPA rules, is a "first draft" that is designed to elicit data and comments. EPA has already signaled that it is evaluating stakeholder concerns about the timing and glide path for meeting interim and final targets, and will evaluate this information as it writes the final rule.

Although we think it is ultimately a good thing that the industry is paying close attention to reliability issues – so that any potential problems can be avoided and addressed in time through planning and infrastructure – we do note recent critiques (e.g., Brattle Group's February 2015 report) of the assumptions used in NERC's recent reliability assessments, which do not take into consideration industry responses to market and reliability signals. This is a significant reason to view the NERC as only having set the table with respect to potential reliability concerns, and to recognize that NERC and many other parties will step up with their important contributions to implementation of the CPP within the electric system reliability context.

IV. Options for Assuring Electric System Reliability in Conjunction with Implementing the Clean Power Plan

The reliability check list

The many comments on the proposed Clean Power Plan submitted to EPA serve as a reminder of the broadly-understood condition that pursuing CO_2 emission reductions in the power sector has to occur in an environment that respects the reliability rules of the game. Like the check list at the start of any endeavor, the comments point out a number of potential items to consider adding to the "to do" list that the electric industry routinely uses to ready itself for reliable system operations.

http://imgkid.com/checklist-icon.shtml

Fortunately, that check list is already robust. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations, placing the country in a good starting position as of the start of 2015. Many of the reliability issues identified in public comments are not new – the industry has responded successfully and effectively to similar challenges in the past. And for several years, some of the trends that commenters note must now be addressed in response to the Clean Power Plan are actually developments that have been underway for many years – and that are currently being addressed. Examples include the FERC's policies addressing: transmission planning taking into account infrastructure needs arising from state-policy (such as renewable portfolio standards); integration of variable electric resources; market designs to assure efficient entry of capacity with attributes needed for reliable system operations; and directives to modify standards and policies so as to better harmonize operations of the electric and gas markets. Other examples include the many studies conducted by RTOs, electric utilities, national laboratories (like the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory), research institutions (such as the Electric Power Research Institute, university research centers, and think tanks) , and the Department of Energy.

These many studies are already pointing out that some of the tools and checklists needed for reliability may need to be enhanced as a result of the many changes underway in the industry. In many respects, the shift towards natural gas-fired generation (driven in large part by fundamental economic forces), the proliferation of variable resources due to economic and policy factors, and the growth in distributed resources in some regions will drive changes in industry planning and operations over a schedule largely coincident with implementation of the Clean Power Plan.

In the end, we think that even if sometimes exaggerated, the reliability "alerts" are actually a good thing: It is appropriate that people are paying attention to reliability issues, so that potential problems can be avoided – and they can be addressed in time through proper planning and appropriate responses. Even if some of the existing tools need to be sharpened or even new ones added, past experience, the capabilities of the industry, the attention of regulators, and the inherent flexibility of Clean Power Plan implementation strongly suggest that the task is manageable. As always, careful planning and advance work is necessary to make sure that there are not inefficient trade-offs between the two core objectives.

The Reliability Toolkit: Which ones to use here?

The U.S. electric system performs so reliably because it includes both clearly defined and clearly assigned roles and responsibilities to particular actors, and also relies upon markets and regulated planning processes to provide an array of workable solutions. This is a very sturdy toolkit to build upon. Our suggestions aim to make it even better by pointing out some extra steps that responsible parties might take to make the toolkit as strong as possible for supporting the changes underway in the industry, including Clean Power Plan implementation.

For this reason, we organize our discussion of tools by identifying those in the hands of "reliability organizations" (like grid operators, FERC, NERC, the states, and others) and those in others' hands (including power plant owners, the markets, and many additional players, including the EPA itself). While the latter may not be "reliability organizations" in the same ways that the institutions in the first group are, they still have significant opportunities (if not genuine responsibility) to take actions to help ensure reliable pathways to compliance with CO_2 emission reductions required from the power sector.

In Table 1 at the beginning of our report, we categorize parties into the following groupings:

- Entities with direct responsibility for critical reliability functions;
- Other public agencies with direct or indirect roles in the Clean Power Plan;
- Owners of existing power plants covered by Section 111(d) of the CAA;
- "Markets" and resource planning/procurement organizations; and
- Other entities with inevitable roles to play in ensuring a reliable system in conjunction with enabling effective and timely compliance with the Clean Power Plan.

Note that in some cases, some parties (e.g., a vertically integrated utility which is a balancing authority and also conducts resource/planning and procurements) may fall into one or more categories.

Then we use those groupings not only to identify the normal, business-as-usual responsibilities of those parties, but also to make a number of suggestions for things that those different players might do in anticipation of heading off potential reliability problems before they arise, or in mitigating impacts if they do. Table 2 makes suggestions for what FERC, NERC, the Regional Reliability Organizations, with Table 3 providing suggestions for System Operators/Balancing Authorities might do, in terms of institutionalizing new studies, reporting requirements, and so forth. Table 4 then focuses on things that other federal agencies can do, with Table 5 suggesting actions by state government entities. Table 6 identifies potential actions that might be considered/adopted as part of organized markets to send appropriate and timely signals for investment, and in parallel, what electric utilities might do within their own resource planning/procurement processes to accomplish reliable outcomes in their geographic footprint. Finally, Table 7 provides a number of suggestions about things that other players might do in their own zones of influence.

In the end, the industry, its reliability regulators and the States have a wide variety of existing and modified tools at their disposal to help as they develop, formalize, and implement their respective State Plans. These two responsibilities – assuring electric system reliability while taking the actions required under law to reduce CO_2 emissions from existing power plants – are compatible, and need not be in tension with each other as long as parties act in timely ways.

This is not to suggest that electricity costs to consumers do not also matter in this context; of course they do. But we observe that too often, commenters make assertions about reliability challenges that really end up being about cost impacts. We think that separating reliability considerations from cost consideration is important so as to avoid distracting attention from the actions necessary (and possible) in order to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution, precisely because they fail to account for the cost of unacceptable system outages to electricity consumers. Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs.

This array of tools is of course subject to important and beneficial social constraints and must be exercised to serve the interests of ratepayers. There is no reason to think that these dual objectives cannot be harmonized within a plan to reduce carbon pollution.

V. Conclusion

In this report we identify the many rules, regulations, institutions, and organizations – in effect, the industry's *standard operating procedures* – for ensuring that EPA's design and administration of the Clean Power Plan in no way jeopardizes or compromises the high level of power system reliability we are used to. Such reliability is essential for the strength of our economy and the public health and safety of our citizens.

In the end, of course, it is a good thing that the industry is paying close attention to reliability issues, so that any potential problems can be avoided – and can be addressed in time through planning and appropriate responses. This is do-able, based on past experience and the capabilities of the industry. As always, careful planning and advance work is necessary to make sure that there are not trade-offs between the two.

Having reviewed the broad range of comments received by EPA with a focus on power system reliability, and the potential reliability challenges posed by Clean Power Plan administration, we find that many of these comments tend to assume inflexible implementation and present worst case scenarios, with an exaggerated cause-and-effect relationship. Moreover, many comments (including those from NERC itself) tend to assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. The history of the electric system and its ability to respond to previous challenges including industry deregulation and previous Clean Air Act regulations such as the NO_x SIP call, SO_2 rule, CSAPR, and MATS prove that this is highly unlikely. These challenges will be solved by the dynamic interplay of regulators and market forces with many solutions proceeding *in parallel*.

Indeed, this dynamic interplay is one reason why a recent survey of more than 400 utility executives nationwide found that more than 60 percent felt optimistic about the Clean Power Plan and felt that EPA should either hold to its current emissions reduction targets or make them more aggressive.[55] Similarly, other market participants announced a willingness and ability to help meet system demand for new natural gas supplies[56] and gas-fired generation, in

[55] The same survey found that those utility executives believed that distributed energy resources offered the biggest growth opportunity over the next five years, and more than 70 percent expect to see a shift away from coal towards natural gas, wind, utility-scale solar and distributed energy. Utility Dive and Siemens, 2015 State of the Electric Utility Survey Results, January 27, 2015. The survey included 433 U.S. electric utility executives from investor-owned, municipal, and electric cooperatives.

[56] See, for example, comments filed by INGAA, December 1, 2014. ("INGAA is confident that … the natural gas pipeline industry can respond to demand for the natural gas pipeline capacity that may be necessary to enable compliance with the Clean Power Plan."). INGAA noted that the existing natural gas pipeline system is already supporting national gas-fired combined-cycle utilization rates of 60 percent during peak periods, which are the same periods when distribution constraints are most likely.

support of the Clean Power Plan.[57] This is in addition to the expanded and innovative solutions and strategies for incremental energy efficiency and distributed energy resources identified by State Regulators and Energy Officials.

There are a number of things states and others can (and, in our view, should) do as part of developing their State Plans to further ensure reliability. First and foremost, states can lean on the comprehensive planning and operational procedures that the industry has relied on to maintain reliability for decades – in the face of both normal operations and sudden changes in markets and policy. These procedures flow from a comprehensive set of laws, rules, protocols, organizations, and industry structures that focus continuously on what is needed to maintain electric reliability.

Second, states should give due consideration to the vast array of tools available to them and the flexibility afforded by the Clean Power Plan in order to ensure compliance is obtained in the most reliable and efficient manner possible. In particular, given the interstate nature of the electric system, we encourage states to enter into agreements with other states or add provisions to state plans that facilitate emission trading between affected power plants in different states; doing so will increase flexibility of the system, mitigate electric system reliability concerns, and lower the overall cost of compliance for all.

[57] See, for example, the comments of Calpine Corporation, filed November 26, 2014. ("With our modern, flexible, and efficient generating fleet, Calpine is prepared to facilitate the successful implementation of the Proposed Clean Power Plan. We are confident that by working constructively with the states and EPA as we have always done, the Clean Power Plan can be a success.")

APPENDIX:
Public Comments on EPA's Proposed Clean Power Plan: Summary of Concerns Relating to Electric System Reliability Issues

As of February 8, 2015, 3.83 million comments have been filed on the EPA's proposed Clean Power Plan.[58] Many organizations have compiled lists and summaries of comments filed by various parties.[59] Most of the comments focus on stringency of the proposed emissions reductions targets, the reasonableness of (and legal bases for) the "building block" methodology used by EPA is setting state targets, the timing of emissions reductions in two periods (interim: 2020-2029); and final (2030 and beyond); the ability of states to develop their State Plans with enough time; and other comments.[60],[61]

[58] Regulations.gov Docket Folder Summary, Docket No. EPA-HQ-OAR-2013-0602, "Standards of Performance for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units," available at http://www.regulations.gov/#!docketDetail;rpp=100;so=DESC;sb=docId;po=0;D=EPA-HQ-OAR-2013-0602.

[59] See, for example: Bipartisan Policy Center (http://bipartisanpolicy.org/wp-content/uploads/2015/02/Comments_Map_Static.pdf); National Association of State Energy Offices (http://111d.naseo.org/); Advanced Energy Economy (http://blog.aee.net/epa-ghg-regs-we-read-the-comments-so-you-dont-have-to-part-1-state-federal-regulator-association); Institute for 21st Century Energy (U.S. Chamber of Commerce); (http://www.energyxxi.org/eparule-stateanalysis; http://www.energyxxi.org/eparule-stateanalysis).

[60] See, for example, comments filed by APPA, December 1, 2014; Business Roundtable, December 1, 2014; Class of '85 Regulatory Response Group, December 1, 2014; CEG, December 1, 2014; CURC, December 1, 2014; Coalition for Innovative Climate Solutions, December 1, 2014; Edison Electric Institute (EEI), December 1, 2014; Electric Power Supply Institute, December 1, 2014; ERCOT, November 17, 2014; Environmental Defense Fund, December 1, 2014; Georgetown Climate Center (with state officials from California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Oregon, Rhode Island, Vermont, and Washington), December 1, 2014; INGAA, December 1, 2014; NARUC, November 19, 2014; NASEO, December 1, 2014; NRDC, December 1, 2014; National Rural Electric Cooperative Association, July 29, 2014; Nuclear Energy Institute (NEI), December 1, 2014; NYISO, November 17, 2014; PJM Interconnection, December 1, 2014; RTO/ISO Council, December 1, 2014; Sierra Club, December 1, 2014; Southern States Energy Council, September 29, 2014; and Western Electricity Coordinating Council (WECC), November 25, 2014.

[61] Even before the final December 1st, 2014 deadline for filing comments, the EPA and other regulators had acknowledged these many public statements and the comments that had been submitted in advance of the deadline. Specifically, in October of 2014, EPA issued a Notice of Data Availability (NODA) that sought comments on three core issues, which we summarize below:

- *Compliance trajectory of emissions reductions from 2020 to 2029*, and in particular, if or how reductions related to building block 2 could be phased in over time (for example, to accommodate constraints in natural gas distribution infrastructure, or how the book life of existing assets could be used to define an alternative glide path) or how states could earn compliance credits for actions taken between 2012 and 2020;
- *Technical assumptions in the building block methodologies for 2 and 3*, including how to consider new gas-fired combined cycle (NGCC) units in state goals, the role of natural gas co-firing at coal plants as a compliance strategy, and if states with little to no existing NGCC capacity should achieve a minimum target of new NGCC generation; and with respect to renewable energy, how or if the EPA could consider alternative goal setting strategies that account for state or regional economic potential of renewables as opposed to relying on existing RPS; and the role of nuclear units in building block 3; and
- *Methodologies for setting State-specific goals*, including the feasibility of using a multi-year baseline (2010-2012) for goal setting, to what extent renewable and energy efficiency goals should be assumed to displace existing fossil generation – as opposed to displacing or avoiding future fossil generation.

The formal NODA is available through Regulations.Gov in Docket No. EPA-HQ-OAR-2013-0602 and informally, through the EPA, here: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-notice-data-availability.

Our own review of submissions from the public and various organizations has focused on issues related to system reliability. These commentaries include concerns raised about one or another aspect of the proposal's impact on the power system's performance. Many comments make suggestions for changes in EPA's proposal, and steps that other entities might take to address reliability issues in the context of compliance with the Clean Power Plan.

A common reliability-related comment is that the EPA did not consider – or seek out the expertise – for how the assumptions it used in setting states' emission reduction targets (i.e., the four "building blocks") may change the operations of the electric grid and how those changes in turn can affect the ability to meet state targets.[62] A similar theme is that the individual state targets do not account for the regional nature of electric grid reliability. Finally, a common concern is that the proposed timeframes for compliance, combined with the interim targets for emissions reductions commencing in 2020, do not provide adequate time for states to develop regional compliance plans or for RTOs to incorporate State Plan provisions into the regional long-term planning frameworks or existing market rules for economic dispatch.

That said, a wide range of regulators and other organizations have committed to working with the EPA and the states to manage these challenges, and in turn, leverage their detailed knowledge of the electric system. As discussed later in this report, many regional coordinators and state regulators already have planning policies and procedures in place that can proceed in parallel with the development of SIPs to ensure the timely development of generation, transmission, and distribution infrastructure needs.[63]

Although the comments do not point to specific known, localized reliability problems identified by a specific commenter, many observers caution that if a state elects not to (or cannot, for one reason or another) accomplish the depth of emission reductions assumed by EPA in state

[62] For example, the EEI noted that "a significant portion of [it's] comments is devoted to explaining how the system operates and how electric utilities, states and system operators engage in complex planning to maintain the reliability of the interconnected power system." Comments filed December 1, 2014, at 12. Similarly, on December 22, 2014, Senator Murkowski (ranking member, Committee on Energy & Natural Resources), Representative Upton (Chairman, Committee on Energy & Commerce), and Representative Whitfield (Chairman, Subcommittee on Energy & Power) requested comment from the FERC Commissioners on their level of involvement and interaction with EPA staff when developing the Clean Power Plan and understanding reliability implications. Letter to FERC from Senator Murkowski, Representative Upton, and Representative Whitfield, December 22, 2014.

[63] Note for example, recent activities among the PJM states: the recent comments submitted to the FERC (Docket No. AD15-4-000: Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure, February 19, 2015) by Michael Kormos, Executive Vice President for Operations, PJM: "PJM has begun this coordination process by engaging state commissions, state environmental regulators responsible for implementing the Clean Power Plan, and EPA starting last year. Recently, PJM has undertaken detailed analyses of scenarios and alternatives that were provided to us by OPSI. Those results have been reviewed with our members and with the states and are posted on our website at http://www.pjm.com/~/media/committeesgroups/committees/mc/20150120-webinar/20150120-item-05-carbon-rule-analysis.ashx.

targets, then the state will inevitably need to make additional cuts from other blocks which will increase the stress on remaining assets and strategies.

Comments on reliability issues thus tend to focus on challenges in system operation that may lead to reliability failures. The commentaries do, however, provide suggestions for how to mitigate the challenges for system reliability failures by building into State Plans alternative strategies for meeting those same targets beyond those incorporated into EPA's target-setting assumptions. For example, comments by both NARUC and NASEO discuss the extensive potential for additional CO_2 savings from energy efficiency projects at the interface of the energy-water nexus and other energy-efficiency initiatives outside of conventional programs administered by electric utilities. Additional guidance or clarification from the EPA on how to account for these programs in State Plans could unleash and incentivize a broad swath of carbon reduction strategies beyond the narrow four building blocks.

Many comments focused on the implications of greater utilization of natural gas-fired power plants on changes in system dispatch and the interdependence of interim and final state goals.[64] Achieving a system-wide 70-percent capacity factor for existing natural-gas combined cycle (NGCC) units, for example, would transition a set of power plants now used largely as intermediate and load-following resources to become base-load capacity resources. Baseload coal-fired generators in place at the end of the 2010s would feel the effects, through either greater cycling of these units, or retention of the units to operate only occasionally if needed to remain on the system for resource adequacy purposes, or retirements. Observers note that cycling such coal-fired units more frequently will decrease their efficiency (i.e., increase their heat rates), as plants use additional energy to overcome the inertia inherent in these units. Commenters' cautions that such impacts will increase the overall fleet average emission profile. The observation is that such interactions will mean that states will need to find additional carbon reductions elsewhere. To the extent that the shift includes greater reliance on renewable energy penetration, then the system operators will need to adjust how they operate the resources on their system to maintain reliability. These variable energy resources do not offer system operators the same level of control (e.g., some may be behind the meter and therefore not even "visible" to operator) for frequency or voltage support nor can they be relied upon to meet load in all hours of the day. In the absence of significant new storage capability on the system, this will increase the need for load-following, fast-ramping resources to respond to

[64] The U.S. Chamber of Commerce Institute for 21st Century Energy reviewed and summarized State comments and found that 35 states raised issue with Building Block 2. This was more than any other category identified by the report. Institute for 21st Century Energy, U.S. Chamber of Commerce. "In Their Own Words: A Guide to States' Concerns Regarding the Environmental Protection Agency's Proposed Greenhouse Gas Regulations for Existing Power Plants", January 22, 2015, page 14.

sudden drops in renewable generation. Traditionally, gas-fired combined cycles or natural gas combustion turbines have met this need. But gas-fired plants that begin to operate more in baseload mode may not be able to perform that load-following function. As described in Section II, Figure 2 above, lead times for implementing peaking generating units and demand-side actions (e.g., programs leading to installation of energy efficiency measures; equipping buildings with automated capability to control demand when signaled to do so by the system operator; adding solar PV panels) are much shorter than those for large power plants and transmission upgrades.

These changes are already underway in part due to the shale gas revolution, state and federal policies supporting renewable energy, other environmental policies. According to some observers, the Clean Power Plan will accelerate such trends. Either way, grid operators will need to address the potential diminishing reservoir of voltage support and inertia that has historically been supplied by coal-fired thermal units with their rotating mass of equipment.

Also, the successful operation of natural gas combustion turbines to balance and integrate intermittent and variable renewable supplies will depend, in turn, on the availability and access to fuel when needed for dispatch. Commenters have suggested, and rightly so, that a significant increase in gas-fired generation will require new gas delivery infrastructure. (We note the recent report published by the U.S. DOE that found, among other things, that the amount of incremental gas infrastructure needed is less than what has been put in place by the industry in the recent past.[65]

> Diverse sources of natural gas supply and demand will reduce the need for additional interstate natural gas pipeline infrastructure. The combination of a geographic shift in regional natural gas production—largely due to the expanded production of natural gas from shale formations—and growth in natural gas demand is projected to require expanded natural gas pipeline capacity. However, the rate of pipeline capacity expansion in the scenarios considered by this analysis is lower than the historical rate of natural gas pipeline capacity expansion. …
>
> (2) Higher utilization of existing interstate natural gas pipeline infrastructure will reduce the need for new pipelines. The U.S. pipeline system is not fully utilized because flow patterns have evolved with changes in supply and demand. …
>
> (3) Incremental interstate natural gas pipeline infrastructure needs in a future with an illustrative national carbon policy are projected to be modest relative to the Reference Case. While a future carbon policy may significantly increase natural gas demand from

[65] U.S. DOE, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015, http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf. After modeling interactions between the gas and electric industries, the report's key findings (at iv-v).

> the electric power sector, the projected incremental increase in natural gas pipeline capacity additions is modest relative to the Reference Case.
>
> (4) While there are constraints to siting new interstate natural gas pipeline infrastructure, the projected pipeline capacity additions in this study are lower than past additions that have accommodated such constraints."

It will take time – in some cases several years – to build this infrastructure, and unlike transmission planning that is coordinated by a central planning authority, expansion of the gas delivery and storage system is driven by market economics. But significant amount of pipeline expansion is already in advanced planning and permitting. Thus, while typically, gas pipeline companies require long-term commitments from 'anchor' gas shippers before receiving permitting approval and proceeding to break ground, there is no reason to believe that the system will be short of capacity as a result of the Clean Power Plan. Indeed, such commitments have and can be made in many regions (notably, in Colorado, as part of the state's approval of Xcel's decision to replace parts of its coal fleet with gas-fired plants, or in the Midwest, where DTE Energy has committed to support pipeline expansion to access gas supplies in the Marcellus). In some organized wholesale electric markets, however, there may need to be changes in some market rules and/or new institutional commitments to induce new investment in firm pipeline expansion to make gas available to non-utility generators.

Another issue raised in many comments relates to the current uncertainty that exists with regard to how states may/should/will count *new* gas-fired combined cycle power plants in their overall planning. Because such new plants fall under a different part of the Clean Air Act (i.e., Section 111(b)) than existing power plants (i.e., Section 111(d)), EPA has suggested that states will have the option to determine whether to fold in new plants into their overall framework for controlling emissions of then-existing power plants, or to keep those new plants regulated under a separate regime. What states will do remains a critical unknown, and could affect the operations of the overall power system, as well as emissions from the plants now covered under the Clean Power Plan.[66]

Beyond regional concerns and detailed technical criticisms, the most frequent reliability-related comments focus on the implications of the interim targets and the timelines for compliance.[67]

---

[66] For example, states with an emission rate goal less than 1,000 lbs/MWh may meet such a target through extensive renewable resources. The use and reliance on new NGCC units (with an emission rate equal to 1,000 lbs/MWh) to provide significant quantities of energy when renewables are off-line may actually increase net total emissions.

[67] The current rule includes two compliance options: a 2030 final goal with an interim compliance goal for average emissions between 2020 and 2029, and a second option, with lower total goals and no interim goals, to be achieved by 2025. Under option 1, States are required to file their SIP by June 30, 2016, with one year extensions available for single states and two years for multi-state plans. EPA has committed to reviewing and approving all SIPs within one year of receipt. Therefore, final SIPs will take effect

Commenters point out that the compliance timeline presents at least two challenges. The first is the added pressure on resource adequacy in light of pending retirements, particularly of economically marginal coal units facing difficult retrofit decisions for compliance with ongoing air regulations such as the MATS.[68] The second is the asserted lack of time for states to develop regional plans for compliance, which could easily require multi-year time frames to coordinate necessary staff in legislative departments, PUCs, and state energy and air offices.

Others have raised the issue that the timelines will result in significant stranded costs for ratepayers.[69] While not a reliability issue per-se, these stranded costs carry a true economic cost in that those monies may have been better spent on other programs in support of the Clean Power Plan project. However, as we discussed we observe that too often, commenters make assertions about reliability challenges that really end up being about cost impacts. We think that separating reliability considerations from cost consideration is important so as to avoid distracting attention from the actions necessary (and possible) in order to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution precisely because they fail to account for the cost of unacceptable system outages to electricity consumers. Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs.

between June 30, 2017 and June 30, 2019. Interim compliance goals for each state are set for the 2020 to 2029 period, in what is commonly referred to as the "glide path" of emission reductions to the 2030 target. The interim compliance goals assume that states can achieve the full quantity of reductions equal to estimates from Building Block 1 and Building Block 2. The "glide" in the interim targets, then, is due to the steady increase in carbon reductions from avoided fossil fuel generation in the 2020-2029 period from increasing levels of renewable energy and energy efficiency deployment.

[68] For example, MISO estimated that between 10 -12 gigawatts of coal-fired capacity will retire by 2016 to meet the MATS rule. An additional 14 gigawatts of coal-fired generation (25 percent of the remaining supply) is further at risk of retirement by 2020. MISO conservatively estimates that it will take a minimum of six years for the necessary generation and transmission infrastructure to replace these retirements. Assuming that all state plans are finalized and approved by 2018, necessary infrastructure would not be in place until 2024 – leaving a four year gap of increased reliability risk. MISO, "Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units," November 2014.

[69] For example, Ameren estimated that the 2020-2029 interim timelines could cost Missouri ratepayers an additional $4 billion compared to its existing Integrated Resource Plan (IRP). Ameren noted that its existing IRP assumes the full retirement of coal units at the end of their useful lives by 2034. The early retirements would move forward the in-service date for proposed NGCC and require additional capacity than would otherwise be needed by 2034. See Comments of Ameren, filed December 1, 2014, at 3.

Acronyms

Acronym	Definition
APPA	American Public Power Association
BPS	Bulk Power System
BTM	Behind the Meter
CAA	Clean Air Act
CAISO	California Independent System Operator
CPP	Clean Power Plan
CO_2	Carbon Dioxide
CSAPR	Cross State Air Pollution Rule
CURC	Coal Utilization Research Council
CWA	Clean Water Act
EEI	Edison Electric Institute
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ERSs	Essential Reliability Services
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
MATS	Mercury and Air Toxics Standard
MISO	Midcontinent Independent System Operator
NAAQS	National Ambient Air Quality Standards
NASEO	National Association of State Energy Officials
NARUC	National Association of Utility Regulatory Commissioners
NEI	Nuclear Energy Institute
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NODA	Notice of Data Availability
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
PJM	PJM Interconnection
PUC	Public Utility Commission
RPS	Renewable Portfolio Standard
RSV	Reliability Safety Valve
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
SIPs	State Implementation Plans
SPP	Southwest Power Pool
VER	Variable Energy Resources (e.g., wind and solar)
WECC	Western Electric Coordination Council

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Technical Conference Docket No. AD23-9-000

Prepared Statement of
Susan F. Tierney, Ph.D.
Senior Advisor, Analysis Group

November 9, 2023

This FERC Reliability Technical Conference provides an important opportunity for the public to be informed and for industry stakeholders to discuss policy issues related to the reliability and security of the Bulk-Power System, including the impact of the Environmental Protection Agency's proposed rule under section 111 of the Clean Air Act on electric reliability. I appreciate being part of this panel.

A common theme in prior instances where EPA issued proposals to control power plant emissions is that industry stakeholders raise concerns that the proposal, if adopted by EPA, would jeopardize electric system reliability and thus conflict with the industry's obligation to provide around-the-clock electricity supply to consumers. Such red flags were raised in 2010 and 2011 about EPA's regulations to control mercury, other harmful emissions and interstate transport of air pollutants, and again in the 2013-2015 period when EPA was considering and eventually proposed regulations to control greenhouse gases emitted from fossil-fueled power plants.

In each of those contexts, I wrote reports and provided testimony and commentary that acknowledged the critical importance of electric system reliability and described the various tools available to the industry to ensure the reliable supply of power even as owners of fossil-fueled generating units were required to take steps to reduce their emissions. Some of these tools were written into the design of EPA's proposals themselves, because in each instance, EPA took into consideration the need to keep the lights on even as power plants complied with new regulations. Other tools are standard elements of the tool kits long available to players in the electric industry.

In every instance in the past dozen years, the industry predictably stepped up to ensure that reliability was not compromised – mainly because these many tools are available and because power plant owners, reliability organizations, regulators, other public officials, and a wide range of other stakeholders take myriad actions to ensure that the grid as a whole performed its essential public service functions.

In fact, in spite of early industry concerns that EPA's 2015 Clean Power Plan would introduce reliability problems if it went into effect (which it never did, after its implementation was stayed by the court and replaced by EPA in 2019), power sector carbon dioxide emissions dropped to 34% below 2005 levels (thus exceeding the Clean Power Plan's goal of reducing such emissions by 32% by 2030) – and without reliability consequences tied to such emissions reductions.

The nation's electric industry has been undergoing significant change over the past decade. The portfolio of generating resources has transitioned, with retirements of significant coal-fired generating capacity, with gas-fired power plants now providing the largest share of electricity supply, and with wind and solar energy making up increasing percentages of electricity. Electricity demand has begun to grow. Fundamental market forces, federal and state policies, and consumer preferences are principal drivers of such changes. Extreme weather events, including frigid cold, droughts, heat waves, wildfires, and torrential downpours and flooding have disrupted energy infrastructure, including on the electricity grid.

Many stakeholders have commented that in light of these circumstances, EPA's recent proposal errs in a number of ways, especially by not allowing more time for compliance and more expansive safety valves to provide more flexibility in the event that reliability problems arise.

Although some of the particulars of the current context are different from in the past, there are many reasons to feel reassured that this new EPA rule will not jeopardize electric system reliability. (I have just completed a new report on these issues.)

First, the electricity reliability institutions, tools and processes in place today are as good as, if not better than, those in place a decade ago. In addition to its important and continually updated reliability assessments of reliability conditions and outlooks, the North American Electric Reliability Council has instituted new assessments and tools to identify reliability risks and to recommend approaches to mitigate them.

Second, significant attention is already being paid by federal and state legislators, reliability organizations, and regulators and other public officials to address confounding circumstances – including gas/electric coordination issues, cybersecurity risks, transitions in generation portfolios, need to enhance the resilience of energy infrastructure, transmission expansion challenges, wholesale market rule considerations, utility forecasting and planning, equity concerns – so as to assure the grid is fit for purpose in the years ahead.

Third, the EPA proposal to curb GHG emissions from existing electric generating units itself includes multiple features to accommodate flexibilities in implementation and compliance-related reliability concerns. These elements of the proposal include: the fact that emissions limits apply only to some subcategories of existing generating units; the long lead times for compliance (with varied deadlines for units with different "operating horizons" and capacity factors); the ability of states to design implementation plans with a degree of allowance trading and banking; the commitment of the Department of Energy to use its authorities in a circumstance where compliance at a particular unit might trigger a local reliability concern; and the proposed rule's "system emergency exclusion for reliability."

Unquestionably, the important reliability risks that currently affect the electric industry must be addressed and there is significant work underway to do so. Regardless of requirements that developers of new gas projects and owners of existing fossil fuel power plants comply with new GHG emission reduction requirements on existing power plants, the electric industry must take the steps necessary to ensure reliability given the many other changes already underway and that are affecting the nation's energy transition.

COLORADO
Energy Office

FERC Reliability Technical Conference, Docket Number AD-23-9-000

Statement of Will Toor,
Executive Director,
Colorado Energy Office
November 9, 2023

Hi, my name is Will Toor and I am the executive director of the Colorado Energy Office. I would like to share the state's perspective on the trajectory of power generation in Colorado, how the EPA's rule is consistent with this trajectory, considerations that will be important to affordability and reliability as EPA finalizes the rule, and important steps that FERC can take.

Colorado is on a trajectory towards deep decarbonization of our electric system. In 2010, 68% of our electricity came from coal. This dropped to 36% in 2022, with gas providing 26%, and renewables providing just under 40% of our electricity[1].

What has enabled this transition is the dramatic decline in the costs of wind and solar, and the increasing skill and experience of our utilities in effectively integrating renewables. The state has a strong working partnership with our utilities, focused on the three pillars of affordability, reliability, and emission reductions. Under adopted electric resource plans, the last coal plant in the state will retire by the end of 2030. Our utilities as a whole are projected to reduce GHG emissions by 84-87% below 2005 levels by 2030.

As we look past 2030, the Energy Office recently contracted for modeling, performed by Ascend Analytics, of pathways to 2040[2]. We asked them to model the lowest cost mix of resources needed to reliably meet projected 2040 load, under a high electrification scenario.

The results were very instructive. In the lowest cost scenario, our grid achieves 98.5% emissions reductions by 2040,. It does this by adding significant amounts of wind solar and batteries, while retaining a gas generation fleet approximately the same size as today's. Over time, the levels of dispatch of gas units goes down dramatically from current levels. By 2040, wind, solar and batteries provide the vast majority of electricity, while the gas units play a very important role in reliability, but provide less than 2% of generation. By 2032, only one gas unit is projected to approach 20% capacity factor, and by 2038, no unit is projected to have a capacity factor over 11%. Thus, simply by minimizing costs to customers, we will likely meet the EPA's requirements,

[1] EIA, Colorado State Energy Profile, https://www.eia.gov/state/print.php?sid=CO
[2] A memo describing the study, titled "SUMMARY OF DRAFT MODELING FOR STUDY ASSESSING CLEAN ENERGY PLANNING FOR 2040IN COLORADO'S ELECTRIC POWER SECTOR", has been submitted to the Commission

since all coal plants in the state will be retired, and we are projecting that no gas plant will have a capacity factor that triggers the EPA requirements.

With that said, we do believe that it will be important, as the EPA finalizes the rules, to ensure maximum flexibility for states to comply in the most cost effective manner. We urge EPA to maximize the ability of states to use trading, averaging and other approaches, at either the individual utility or statewide level, to develop plans that meet the emissions reduction requirements while maintaining reliability and minimizing costs to customers. This should include an ability for states to recognize the changing use of existing gas plants over time.

In order to minimize any potential impact on reliability, EPA should consider rules for state plans that incorporate:

- Allowing demonstration with the rule requirements based on actual operating information, rather than strict permit restrictions
- Allow use of modeling data in the initial state plan development along with ongoing reporting of operating data to ensure emissions are on track to meet plan obligations
- Consider multi year averages for demonstration of compliance as a way to account for unexpected system reliability conditions.

We believe that the most important steps that FERC can take to assure reliability in the context of the EPA rules is to take actions to speed up interconnection, improve long term transmission planning, and support the buildout of inter regional transmission.

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

MIKE O'BOYLE, DAN ESPOSITO, MICHELLE SOLOMON, AND BRENDAN PIERPONT

NOVEMBER 2023

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

ENERGY INNOVATION
POLICY & TECHNOLOGY LLC®

www.energyinnovation.org

98 Battery Street, Suite 202
San Francisco, CA 94111
policy@energyinnovation.org

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.

Table of Contents

ACKNOWLEDGEMENTS

The authors gratefully acknowledge insights and feedback from Carrie Jenks and Hannah Dobie of the Harvard Law School Energy and Environmental Law Program; Ric O'Connell and Michael Milligan of GridLab; Peter Heisler, Jonas Monast, and Grace Van Horn of the Center for Applied Environmental Law and Policy; and Chris Grundler. We also thank Energy Innovation staff for contributions to this report, especially Eric Gimon, Anand Gopal, Silvio Marcacci, and Shannon Stirone. The thoughts expressed here, and any errors or omissions thereof are the sole responsibility of the authors.

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

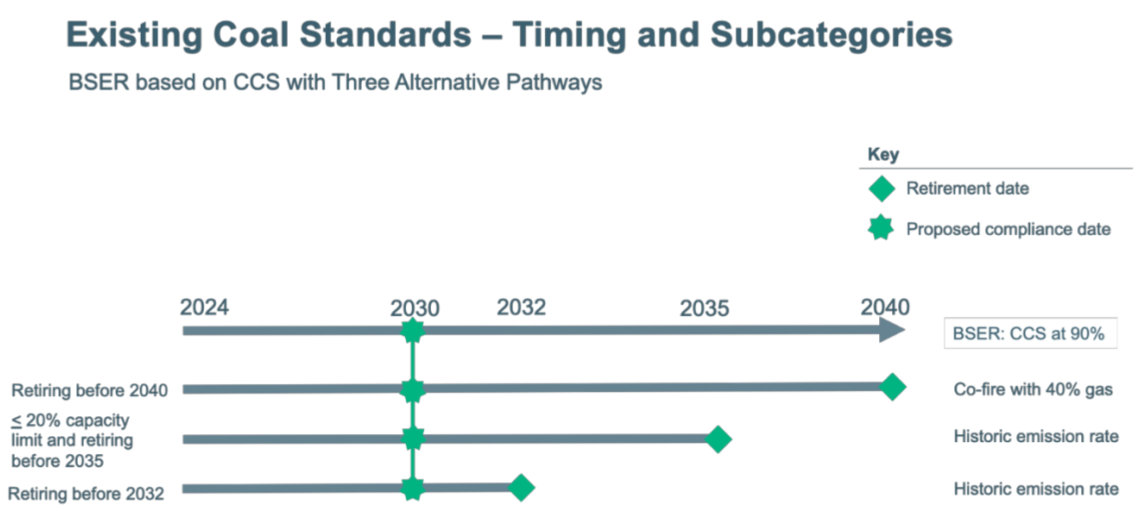
While the EPA's proposed rules are largely representative of the existing transition away from coal, the rules have raised reliability and feasibility concerns from various stakeholders. Industry concerns largely focus on the transitional period between a fossil-dependent grid and a clean grid, as opposed 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



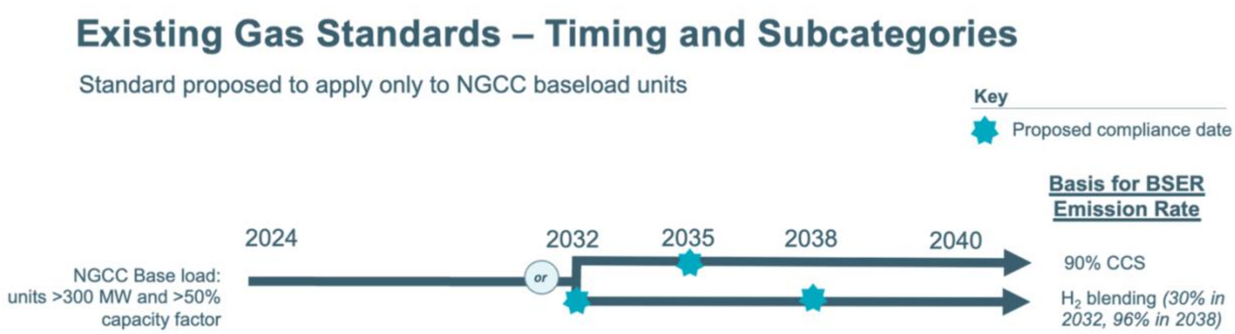
Source: Harvard Law School Environmental & Energy Law Program, 2023.[9]

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



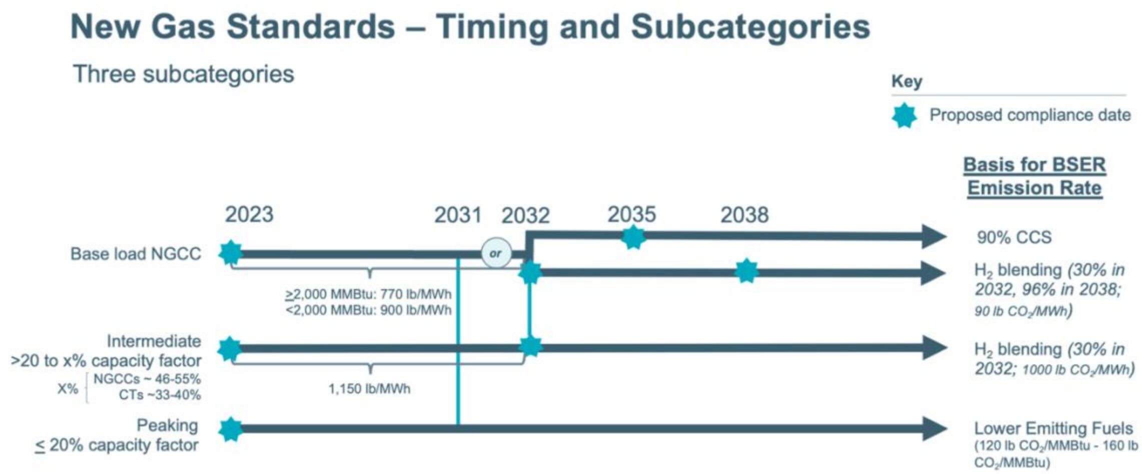
Source: Harvard Law School Environmental & Energy Law Program, 2023[11]

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



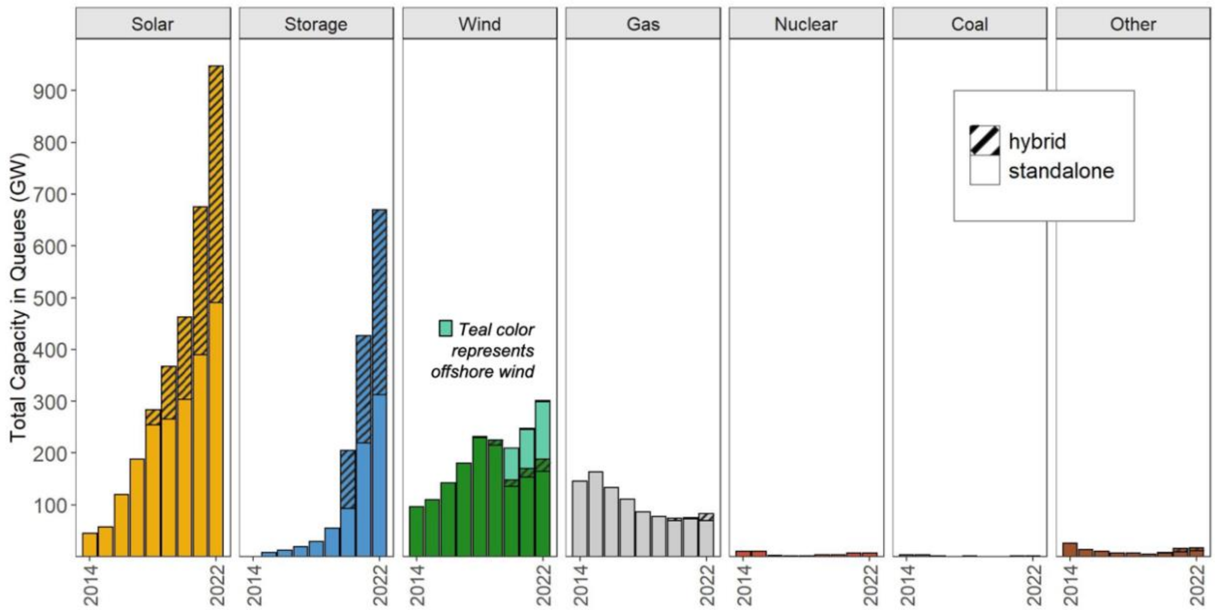
Source: Harvard Law School Environmental & Energy Law Program, 2023.[12]

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.

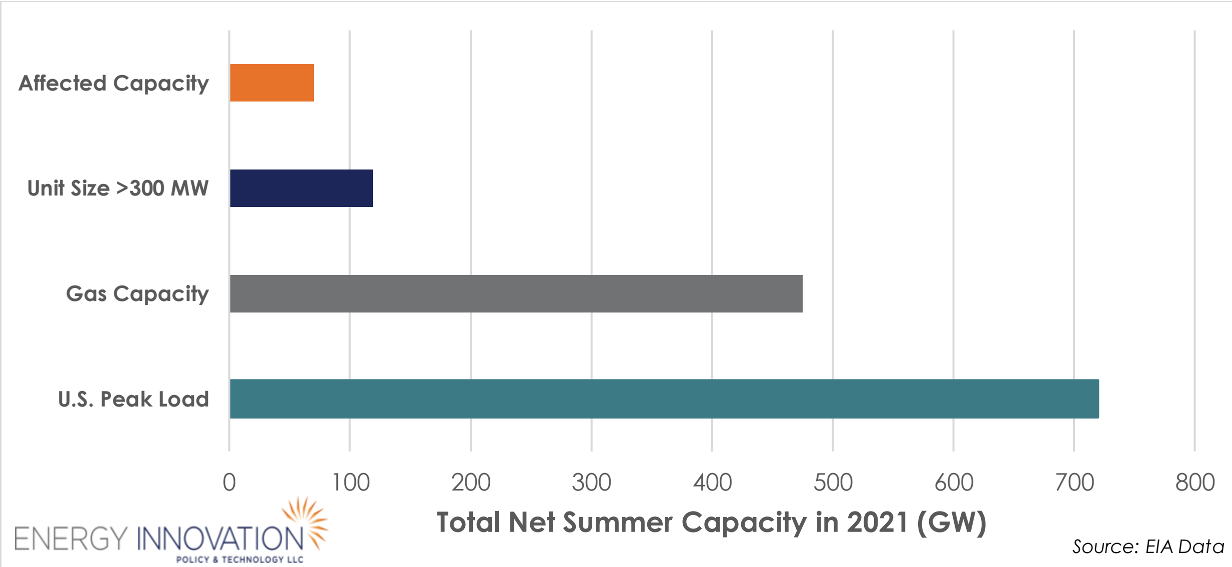
Unlike limitations on existing coal, rules affecting existing gas are less likely to result in retirements, due to limited coverage of the rules and the ability for covered units to avoid regulation by reducing their average output (which could be backfilled by existing exempt units increasing their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

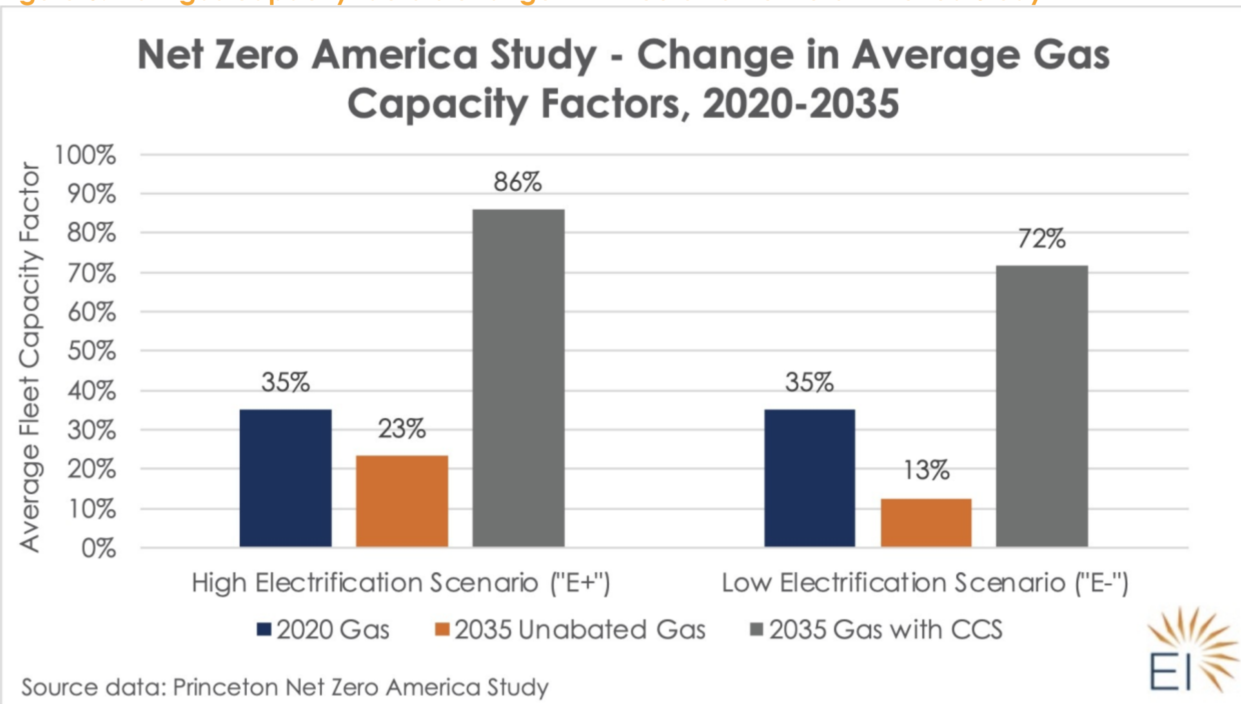
The increased renewable deployment would displace both existing coal generation and natural gas generation, as wind and solar fuels are zero marginal cost, yet each model was able to maintain resource adequacy through the study period despite differences in time and geography.

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.

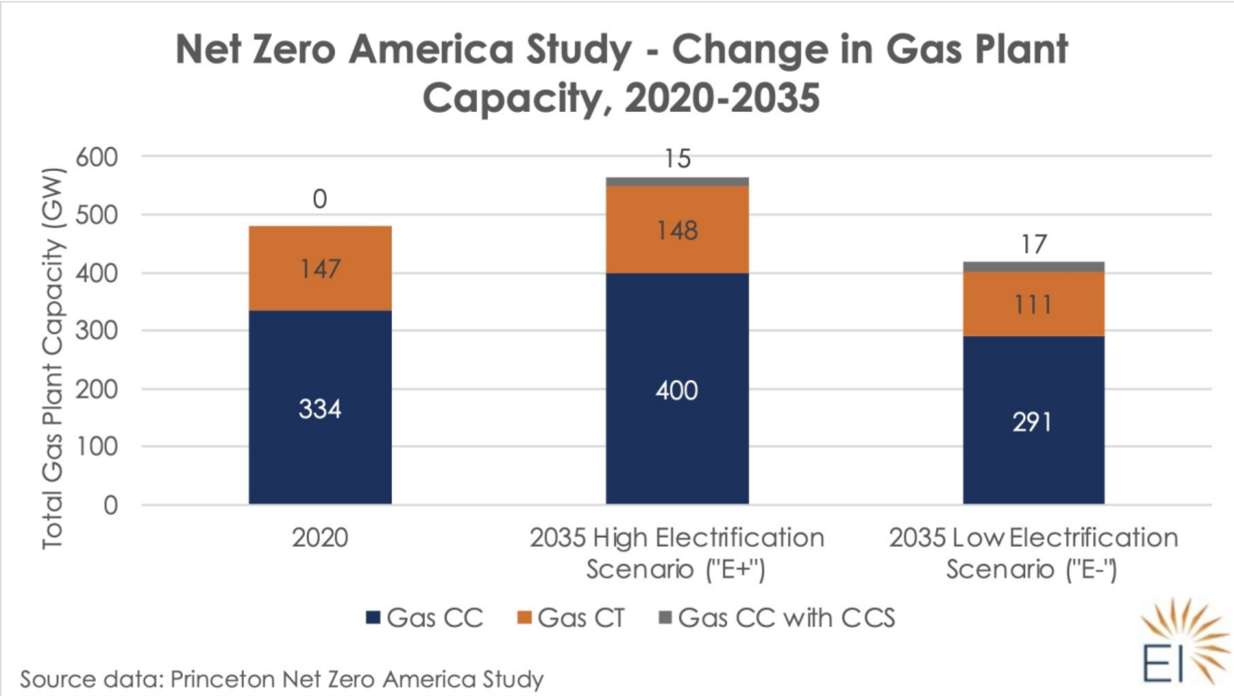
electrification scenario and that the grid can maintain resource adequacy relying on the existing gas fleet operating at much lower average capacity factors.

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

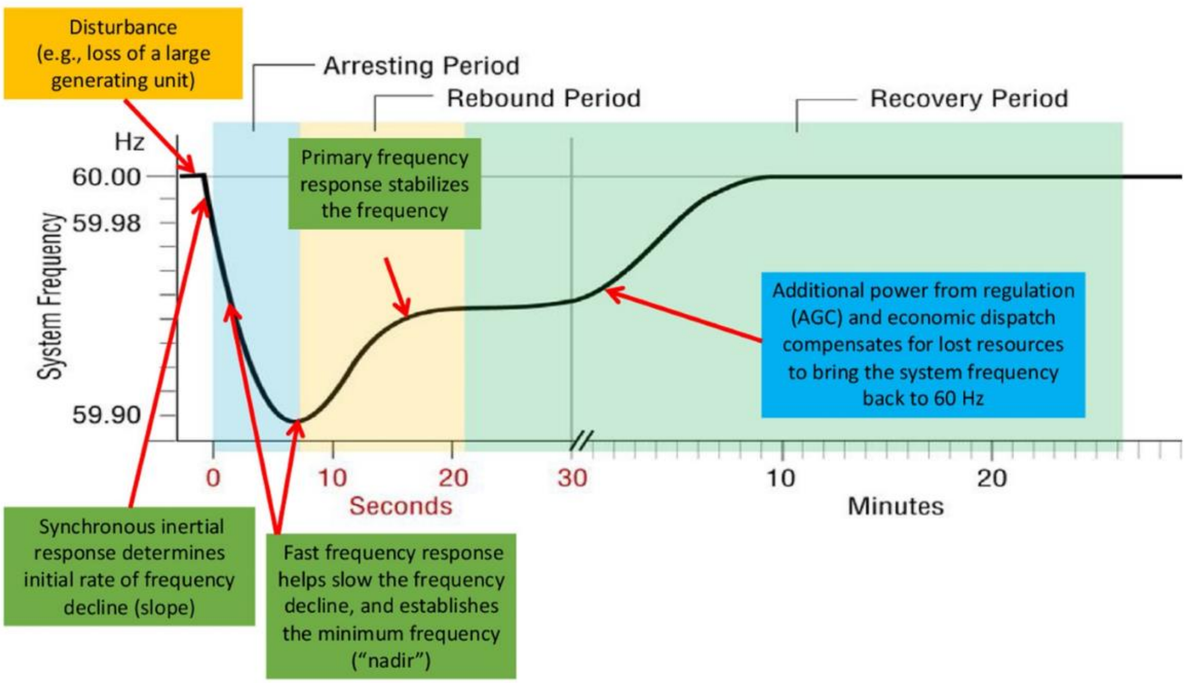
The ERS required to maintain grid stability include disturbance ride-through, inertia, reactive power and voltage support, fast frequency response, primary frequency response, automatic generation control, and dispatch/flexibility.[39] These services work on different timescales to stabilize frequency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

[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

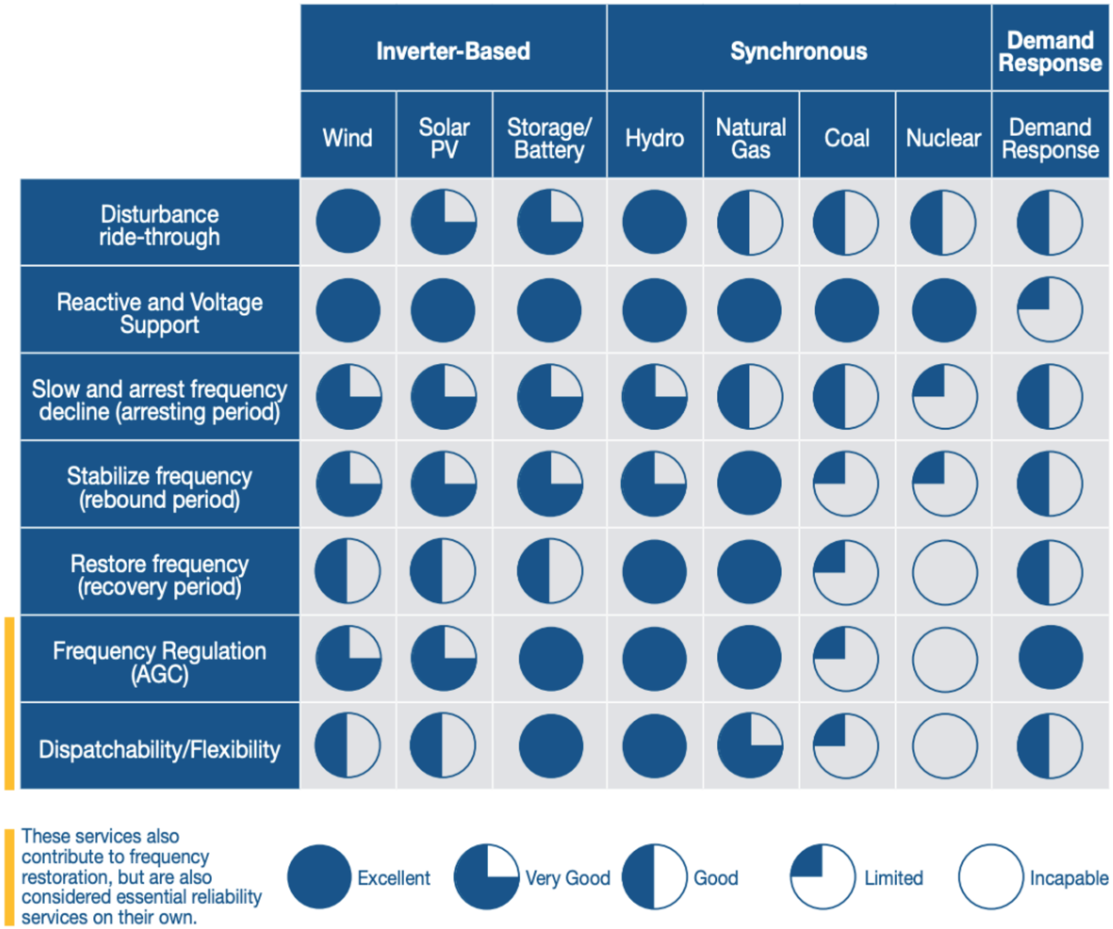
As seen in Figure 9, all mature resources on the grid today provide some degree of ERS, but with different characteristics. Ultimately, ERS is not a single-resource problem: Whether they are sufficient depends on the portfolio and location of resources, which include controls that are embedded within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

---

[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.

---

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.

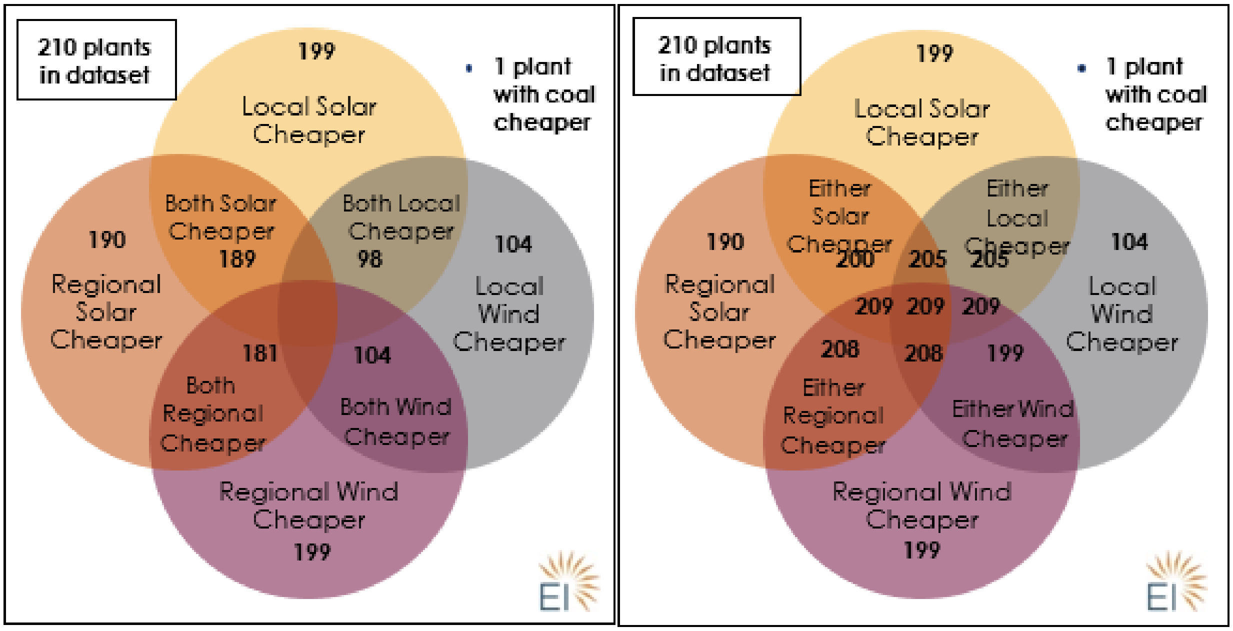
Regulators should require examination of GETs within integrated resource planning to ensure these solutions are not overlooked. Grid operators should examine the potential for these new technologies to add capacity to the existing system within the compliance timeline provided by the EPA's rules. The 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.

[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

---

[1] James Robb, "Testimony of James B. Robb" (The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts, Before the Committee on Energy and Natural Resources United States Senate, June 1, 2023), https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11.

[2] "New Source Performance Standards for Greenhouse Gas Emissions from New and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," (88 FR 33240) (FRL-8536-02-OAR) Federal Register, https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0001.

[3] "Energy Innovation Comments to the EPA's Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units and Repeal of the Affordable Clean Energy Rule" (Energy Innovation, August 8, 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0629/attachment_1.pdf.

[4] Katherine Antonio, "Renewable Generation Surpassed Coal and Nuclear in the U.S. Electric Power Sector in 2022," U.S. Energy Information Administration, March 27, 2023, https://www.eia.gov/todayinenergy/detail.php?id=55960.

[5] Michelle Solomon, Eric Gimon, and Mike O'Boyle, *Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment* (Energy Innovation, January 2023), https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.

[6] "Comment Submitted by Edison Electric Institute to the Environmental Protection Agency" (Edison Electric Institute, August 15, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0772.

[7] "Comment Submitted by National Rural Electric Cooperative Association to the Environmental Protection Agency" (National Rural Electric Cooperative Association, August 15, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0770.

[8] See generally, "Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act" (U.S. Environmental Protection Agency, 2013), https://archive.epa.gov/epa/sites/production/files/2013-09/documents/111background.pdf.

[9] Robin Just, "EPA's Proposed Greenhouse Gas Emission Standards for Power Plants Are Consistent with Statutory Factors and Market Trends" (Harvard Law School, May 19, 2023), https://eelp.law.harvard.edu/2023/05/epas-proposed-greenhouse-gas-emission-standards-for-power-plants-are-consistent-with-statutory-factors-and-market-trends/.

[10] Richard Kornitsky and Kim Quach, "Overview of ISO-NE's Comments on EPA's Proposed GHG Rule."

[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."

[13] Carrie Jenks et al., "EPA's Proposed Greenhouse Gas Emission Standards for Power Plants Are Consistent with Statutory Factors and Market Trends" (Harvard Law School Environmental and Energy Law Program, May 19, 2023), http://eelp.law.harvard.edu/wp-content/uploads/111-Power-Sector-Proposal-Summary-EELP.pdf.

[14] Joseph Rand et al., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022* (Lawrence Berkeley National Laboratory, April 2023), https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf.

[15] Joseph Rand et al., "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022" (Lawrence Berkeley National Lab, April 2023), https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf.

[16] "Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (U.S. Environmental Protection Agency, May 2023), tbl 3-14, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

[17] "Resource Adequacy Analysis Technical Support Document" (U.S. Environmental Protection Agency, May 2023), 3, https://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf.

[18] Will Wade, "New York's Last Coal-Fired Power Plant to Retire Tuesday," *Bloomberg*, March 30, 2020, https://www.bloomberg.com/news/articles/2020-03-30/new-york-s-last-coal-fired-power-plant-will-shut-down-tuesday.

[19] Scott Merrill and Jill Patel, "How New England's Last Coal-Fired Power Plant Has Managed to Survive," *Concord Monitor*, January 7, 2023, https://www.concordmonitor.com/Understanding-the-longevity-of-Merrimack-Station-49449084.

[20] "California State Profile and Energy Estimates," U.S. Energy Information Administration, April 20, 2023, https://www.eia.gov/state/analysis.php?sid=CA.

[21] Paul Denholm et al., *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035* (National Renewable Energy Laboratory, August 30, 2022), https://doi.org/10.2172/1885591.

[22] Daniel Steinberg et al., *Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System* (National Renewable Energy Laboratory, March 15, 2023), https://doi.org/10.2172/1962552.

[23] Eric Larson et al., *Net Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report* (Princeton University, October 2021), https://netzeroamerica.princeton.edu/the-report.

[24] Amol Phadke et al., *2035 The Report: Transportation - Plummeting Costs and Dramatic Improvements in Batteries Can Accelerate Our Clean Transportation Future* (University of California, Berkeley; GridLab; Energy Innovation, May 2020), http://www.2035report.com/transportation/wp-content/uploads/2020/05/2035Report2.0-1.pdf.

[25] Derek Stenclik, Michael Welch, and Priya Sreedharan, *Reliably Reaching California's Clean Electricity Targets: Stress Testing Accelerated 2030 Clean Portfolios* (GridLab; Telos Energy; Energy Innovation, May 2022), https://gridlab.org/wp-content/uploads/2022/05/GridLab_California-2030-Study-Technical-Report-5-9-22-Update1.pdf.

[26] Qingyu Xu et al., *Cleaner, Faster, Cheaper: Impacts of the Inflation Reduction Act and a Blueprint for Rapid Decarbonization in the PJM Interconnection* (Princeton University, December 12, 2022), https://doi.org/10.5281/zenodo.7429042.

[27] Steinberg et al., *Evaluating Impacts of the Inflation Reduction Act*, 9-10.

[28] Phadke et al., *2035 The Report: Transportation*.

[29] Stenclik, Welch, and Sreedharan, *Reliably Reaching California's Clean Electricity Targets*, 56.

[30] See generally U.S. Department of Energy Office of Nuclear Energy, "Inflation Reduction Act Keeps Momentum Building for Nuclear Power," September 8, 2022, https://www.energy.gov/ne/articles/inflation-reduction-act-keeps-momentum-building-nuclear-power.

[31] Kevin Clark, "Explaining the delays of U.S. coal plant retirements," Power Engineering, August 23, 2022, https://www.power-eng.com/coal/explaining-the-delays-of-u-s-coal-plant-retirements/#gref.

[32] Sami Abdulsalam, "Data Center Planning & Need Assessment Update" (PJM, January 10, 2023), https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230110/item-04---data-center-load-planning.ashx, slide 3.

[33] Peter Judge, "Dominion Energy admits it can't meet data center power demands in Virginia," Data Center Dynamics, July 29, 2022, https://www.datacenterdynamics.com/en/news/dominion-energy-admits-it-cant-meet-data-center-power-demands-in-virginia/.

[34] "Comments Submitted by the Southwest Power Pool to the Environmental Protection Agency" (Southwest Power Pool, August 13, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0670.

[35] "Comments Submitted by the Electric Reliability Council of Texas et al. to the Environmental Protection Agency" (Joint ISOs/RTOs, August 13, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0673.

[36] Julia Matevosyan, *A Unique Window of Opportunity: Capturing the Reliability Benefits of Grid-Forming Batteries* (Energy Systems Integration Group, March 2023), https://www.esig.energy/wp-content/uploads/2023/03/ESIG-GFM-batteries-brief-2023.pdf.

[37] Federal Energy Regulatory Commission, "Reliability Standards to Address Inverter-Based Resources, Proposed Rule," Docket No. RM22-12-000, https://www.federalregister.gov/documents/2022/12/06/2022-25599/reliability-standards-to-address-inverter-based-resources.

[38] FERC, "Order 901 - Reliability Standards to Address Inverter-Based Resources," 18 CFR Part 40 § (2023), https://www.ferc.gov/media/e-1-rm22-12-000.

[39] Michael Milligan, "Sources of Grid Reliability Services," *The Electricity Journal* 31, no. 9 (November 1, 2018): 1-7, https://www.sciencedirect.com/science/article/pii/S104061901830215X.

[40] Michael Milligan, "Sources of Grid Reliability Services," Figure 2.

41 Milligan, "Sources of Grid Reliability Services."

[42] Peter Fairley, "Zombie Coal Plants Reanimated to Stabilize the Grid," *IEEE Spectrum*, July 24, 2015, https://spectrum.ieee.org/zombie-coal-plants-reanimated-to-stabilize-the-grid.

[43] Jeffrey Rissman and Eric Gimon, "Decarbonizing U.S. Industry While Supporting a High-Renewables Grid," July 2023, https://energyinnovation.org/wp-content/uploads/2023/07/2023-07-13-Industrial-Thermal-Batteries-Report-v133.pdf.

[44] "Industry Recommendation: Inverter-Based Resource Performance Issues" (North American Electric Reliability Corporation, March 14, 2023), https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf.

[45] Paul Denholm et al., *Inertia and the Power Grid: A Guide Without the Spin* (National Renewable Energy Laboratory, May 1, 2020), https://www.nrel.gov/docs/fy20osti/73856.pdf.

[46] Peter Fairley, "Can Synthetic Inertia from Wind Power Stabilize Grids?," *IEEE Spectrum*, November 7, 2016, https://spectrum.ieee.org/can-synthetic-inertia-stabilize-power-grids.

[47] See generally Julia Matevosyan, "A Unique Window of Opportunity: Capturing the Reliability Benefits of Grid-Forming Batteries" (ESIG, March 2023), https://www.esig.energy/wp-content/uploads/2023/03/ESIG-GFM-batteries-brief-2023.pdf.

[49] "MISO's Renewable Integration Impact Assessment (RIIA), Summary Report" (Midcontinent ISO, February 2021), https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

[50] See generally Yinong Sun, *Research Priorities and Opportunities in United States Competitive Wholesale Electricity Markets* (Grid Modernization Laboratory Consortium, May 2021), https://www.nrel.gov/docs/fy21osti/77521.pdf.

[51] Michael Milligan, "Reply Comments of Michael Milligan, Ph.D.: Grid Reliability and Resiliency Pricing, Docket No. RM18-1-000," 2017, http://www.milligangridsolutions.com/Milligan-Comments-FERC%20from%20ferc%20web.pdf.

[52] Federal Energy Regulatory Commission, "Order 2023."

[53] Tyler H. Norris, *Beyond FERC Order 2023: Considerations on Deep Interconnection Reform* (Nicholas Institute for Energy, Environment & Sustainability, Duke University, August 22, 2023), https://nicholasinstitute.duke.edu/publications/beyond-ferc-order-2023-considerations-deep-interconnection-reform.

[54] Bruce Tsuchida, Stephanie Ross, and Adam Bigelow, *Unlocking the Queue with Grid Enhancing Technologies* (WATT Coalition, February 1, 2021), https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

[55] Ethan Howland, "FERC Approves MISO Reliability Contract to Keep Ameren Missouri's Rush Island Coal Plant Operating," Utility Dive, October 26, 2022, https://www.utilitydive.com/news/ameren-rush-island-ferc-miso-reliability-ssr-contract/634977/.

[56] Federal Energy Regulatory Commission, "FERC Issues Transmission NOPR Addressing Planning, Cost Allocation," April 21, 2022, https://www.ferc.gov/news-events/news/ferc-issues-transmission-nopr-addressing-planning-cost-allocation.

[57] Solomon, Gimon, and O'Boyle, *Coal Cost Crossover.*

[58] Michelle Solomon, Eric Gimon, and Mike O'Boyle, "Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment" (Energy Innovation, January 2023), https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.

[59] U.S. Environmental Protection Agency, "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule," 2023, Section XII.

[60] Portland General Electric, "Clean Energy Plan and Integrated Resource Plan 2023," 2023, https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf.

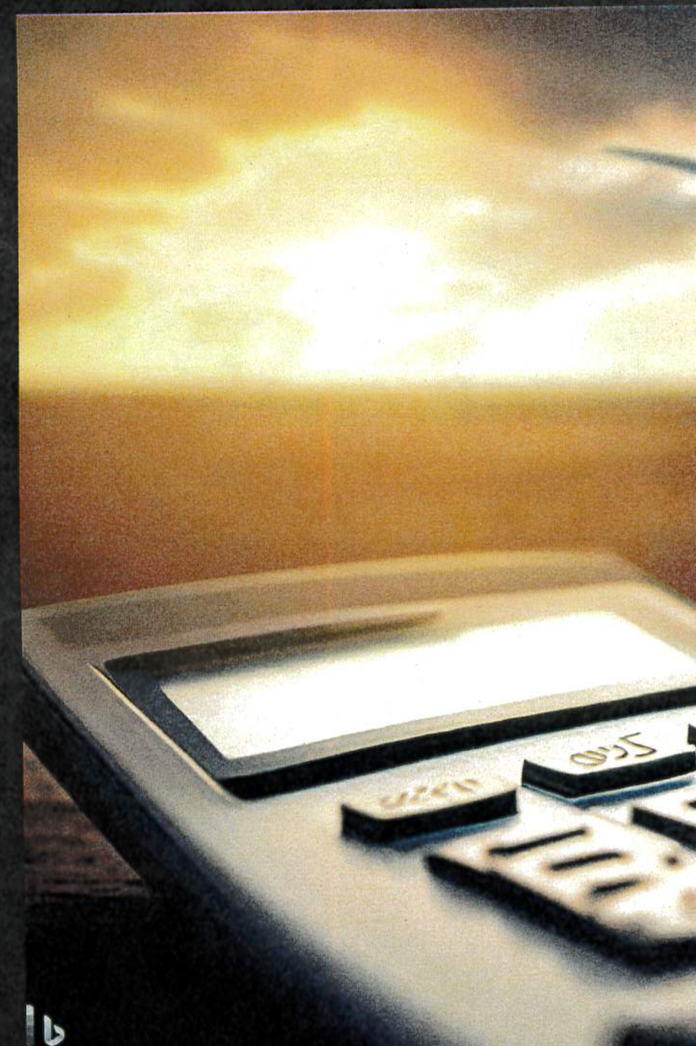
[61] Energy Innovation, "All-Source Utility Electricity Generation Procurement Best Practices," 2020, https://energyinnovation.org/publication/making-the-most-of-the-power-plant-market-best-practices-for-all-source-procurement-of-electric-generation/all-source-utility-electricity-generation-procurement-best-practices/.
[62] U.S. Energy Information Administration, Form 930 Data, via "Real-Time Operating Grid," accessed July 31, 2023, https://www.eia.gov/electricity/gridmonitor/index.php.
[63] U.S. Energy Information Administration, "Electric Power Monthly," accessed July 31, 2023, Table 6.2.C., https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_c.
[64] Smart Electric Power Alliance, "Utility Carbon-Reduction Tracker™," accessed July 31, 2023, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.
[65] Colorado Public Service Commission, "Phase I Decision," (Decision No. C22-0459, Proceeding No. 21A-0141E), August 3, 2022.
[66] Xcel Energy, "2021 Electric Resource Plan and Clean Energy Plan," (Proceeding No. 21A-0141E), March 31, 2021.
[67] Xcel Energy, "Upper Midwest Integrated Resource Plan, Supplement, 2020-2034," (Docket No. E002/RP-19-368, 2020), https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/Upper-Midwest-Energy-Plan-Supplement-063020.PDF.
[68] Xcel Energy, "Upper Midwest Integrated Resource Plan, Supplement," 63.
[69] Xcel Energy, "Upper Midwest Integrated Resource Plan, Supplement," 63.
[70] Xcel Energy, "Upper Midwest Integrated Resource Plan 2020-2034, Reply Comments" (Docket No. E002/RP-19-368), 113, https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={70F0437A-0000-CF1C-96D6-E7E22CE60B9C}&documentTitle=20216-175386-01.
[71] Xcel Energy, "Upper Midwest Integrated Resource Plan," 5.
[72] Xcel Energy, "Upper Midwest Integrated Resource Plan," 30-53.
[73] Northern Indiana Public Service Company LLC, "2021 Integrated Resource Plan," November 15, 2021, 14, https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf?sfvrsn=6.
[74] Northern Indiana Public Service Company LLC, "2018 Integrated Resource Plan," October 31, 2018, 5, https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf.
[75] Northern Indiana Public Service Company LLC, "2021 Integrated Resource Plan."
[76] Northern Indiana Public Service Company LLC, "2021 Integrated Resource Plan," 259.
[77] Northern Indiana Public Service Company LLC, "2021 Integrated Resource Plan," Appendix E.
[78] RMI, *Maximizing the Financial Opportunity of the New ERA Program*, June 12, 2023, https://rmi.org/wp-content/uploads/dlm_uploads/2023/06/Maximizing-the-Financial-Opportunity-of-the-New-ERA-Program.pdf.
[79] U.S. Department of Agriculture, "Empowering Rural America New ERA Program," accessed July 2023, https://www.rd.usda.gov/programs-services/electric-programs/empowering-rural-america-new-era-program.
[80] Great River Energy, "2023-2037 Integrated Resource Plan," Docket No. ET-2/RP-22-75, March 31, 2023, 8, https://greatriverenergy.com/wp-content/uploads/2023/03/2023-IRP-FINAL.pdf.
[81] Presentation by Jon Brekke to Minnesota Legislative Energy Commission, November 2020, https://www.lec.mn.gov/2020/Legislative%20Energy%20Commission%20JBrekke%20111320_1.pdf.
[82] Great River Energy, "2023-2037 Integrated Resource Plan," 13.
[83] Presentation by Brekke.
[84] Great River Energy, "2023-2037 Integrated Resource Plan," 11.
[85] U.S. Energy Information Agency, Form 861, 2021.
[86] CPS Energy, "2022 Power Generation Plan Initial Reference Case Results Discussion, Rate Advisory Committee Meeting – October 20, 2022," 45. Figures estimated from graphic.
[87] CPS Energy, "2022 Power Generation Plan Initial Reference Case Results Discussion," 16.
[88] CPS Energy, "2022 Power Generation Plan Initial Reference Case Results Discussion," 45.
[89] CPS Energy, "2022 Power Generation Plan Initial Reference Case Results Discussion," 18.

[90] CPS Energy, "2022 Power Generation Plan Results Discussion, Rate Advisory Committee Meeting – November 17, 2022," 15, https://www.cpsenergy.com/content/dam/corporate/en/Documents/RAC/November%20RAC%20Presentation%20-%20Final%20Updated%2011-16.pdf.

[91] See generally Solomon, Gimon, and O'Boyle, "Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment."

[92] Michael O'Boyle, "Why the American Jobs Plan Would Benefit Coal-Heavy Utility Stocks," *Forbes*, July 12, 2021, https://www.forbes.com/sites/energyinnovation/2021/07/12/why-the-american-jobs-plan-would-benefit-coal-heavy-utility-stocks/.

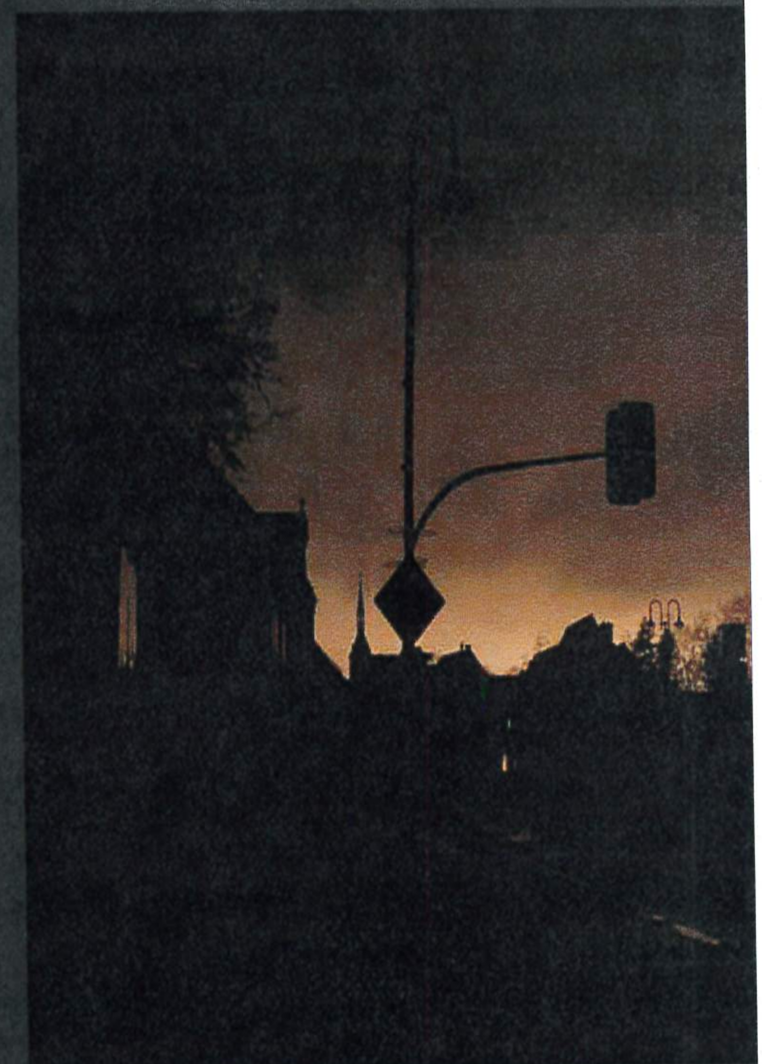
Calculating the True Cost of the EPA's Carbon Dioxide Regulations



AMERICAN EXPERIMENT

American Experiment Analysis of EPA's Proposed CO_2 Rules in MISO

- American Experiment modeled the resource adequacy, reliability, and cost of EPA's proposed CO_2 rules for new and existing fossil fueled power plants.
- We determined EPA's modeled MISO grid under the rules would not meet resource adequacy or reliability.
- Meeting EPA's emissions targets without blackouts would cost MISO ratepayers an additional $246 billion compared to EPA's assumed grid.
- The regulations and IRA subsidies would result in massive rolling blackouts.
- The $246 billion price tag in MISO amounts to $7.7 billion per year, which exceeds EPA's net benefit calculations for the entire country ($5.9 billion).

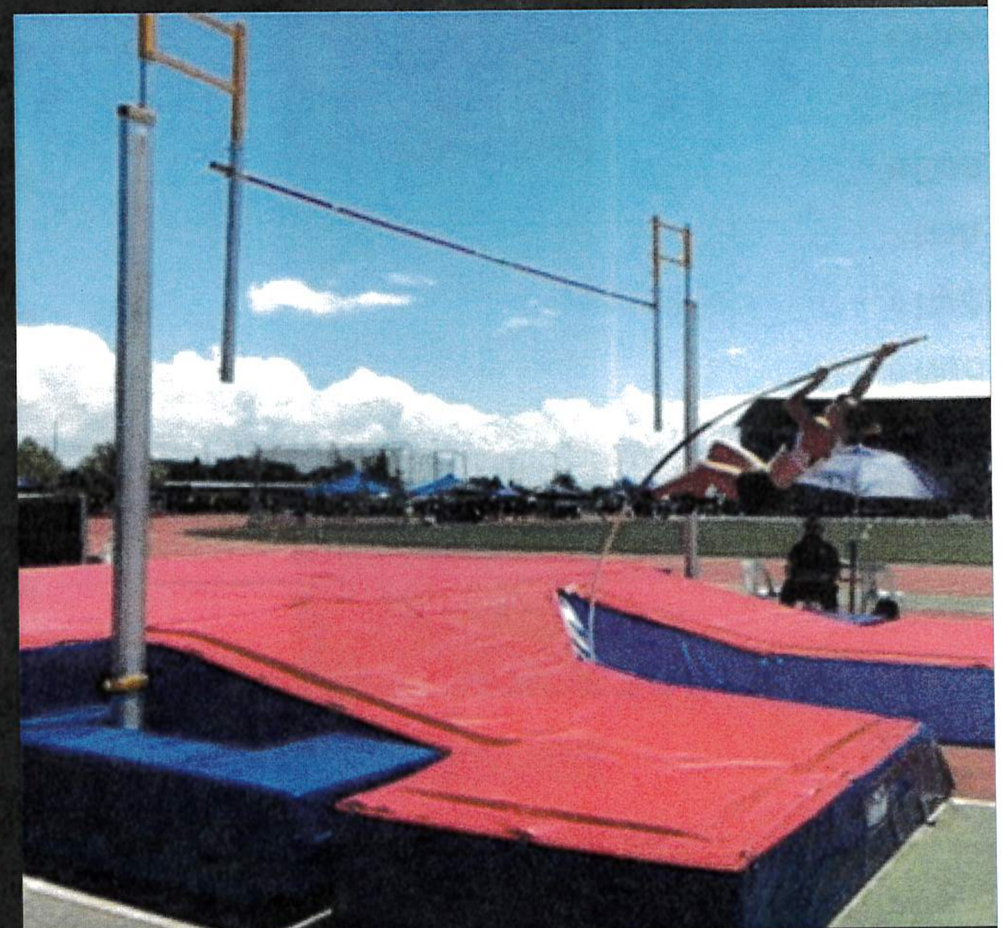


AMERICAN EXPERIMENT

Midcontinent Independent System Operator

What is Resource Adequacy?

- Resource adequacy is kind of like pole vaulting.
- You need to enough reliable power plants to meet your projected peak electricity demand, plus a margin of safety.



A's Modeled Grid Would Preserve Resource Adequ to the Base Case, But…

- EPA has narrowly defined the scope of the Regulatory Impact Analysis (RIA) of the regulations to maintain resource adequacy ***<u>compared to its Post-IRA base case.</u>***
- EPA assumes **99 percent** of the emissions reductions in this proposal occur due to the Inflation Reduction Act subsidies in its base case.
- EPA did not evaluate the resource adequacy or reliability of its Post-IRA base case, it simply assumed they are sufficient.

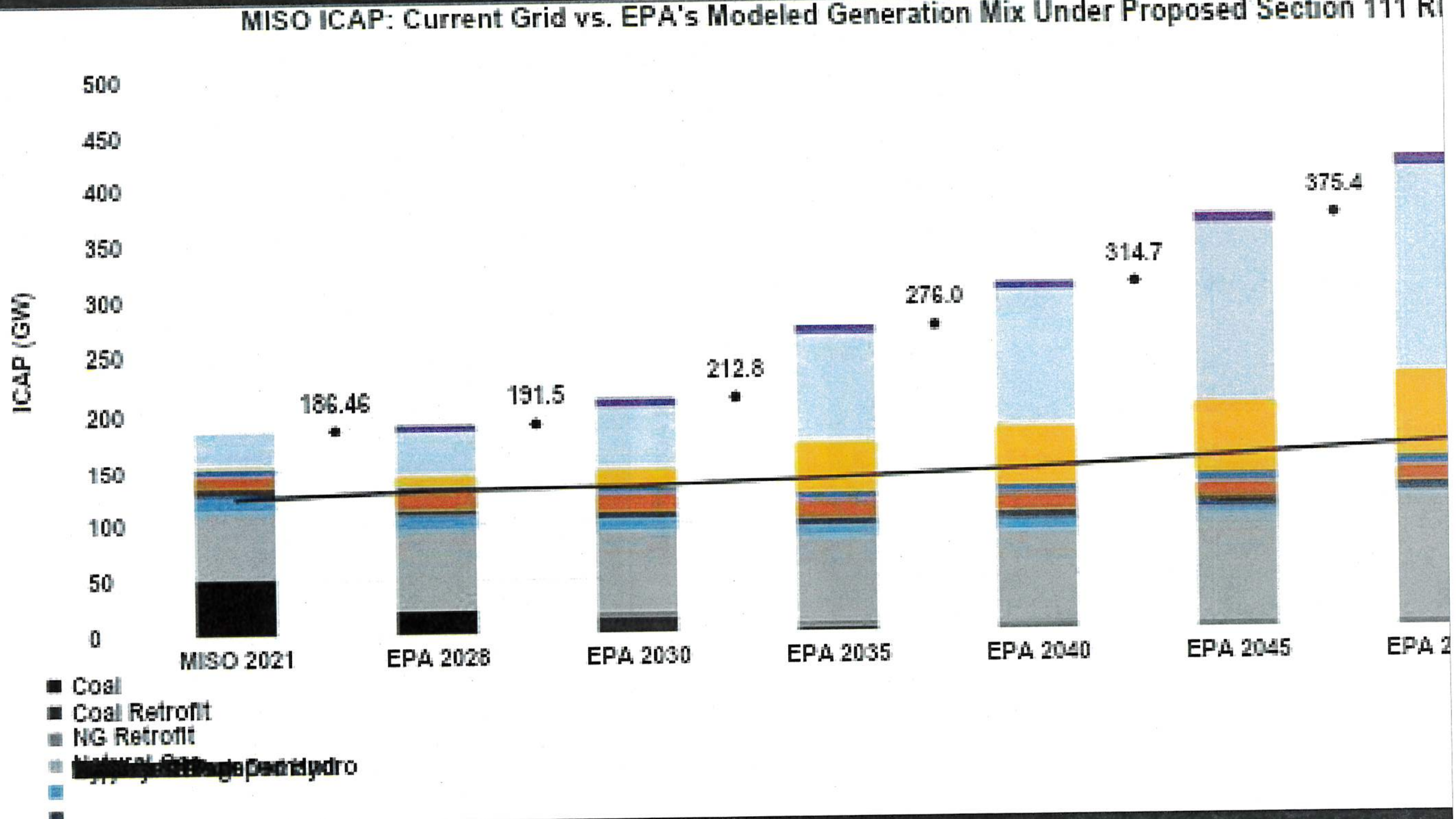
"The results presented in this document further demon specific cases illustrated in the Regulatory Impact Ana the implementation of these rules can be achieved wit resource adequacy."

"The focus of the analysis is on ***comparing the illustr rules scenario from the RIA to a base case (absent th requirements) that is assumed to be adequate and rel added]***

"In this framework, we emphasize the incremental cha system that are projected to occur under the presence c 2030, 2035 and 2040 model run years."

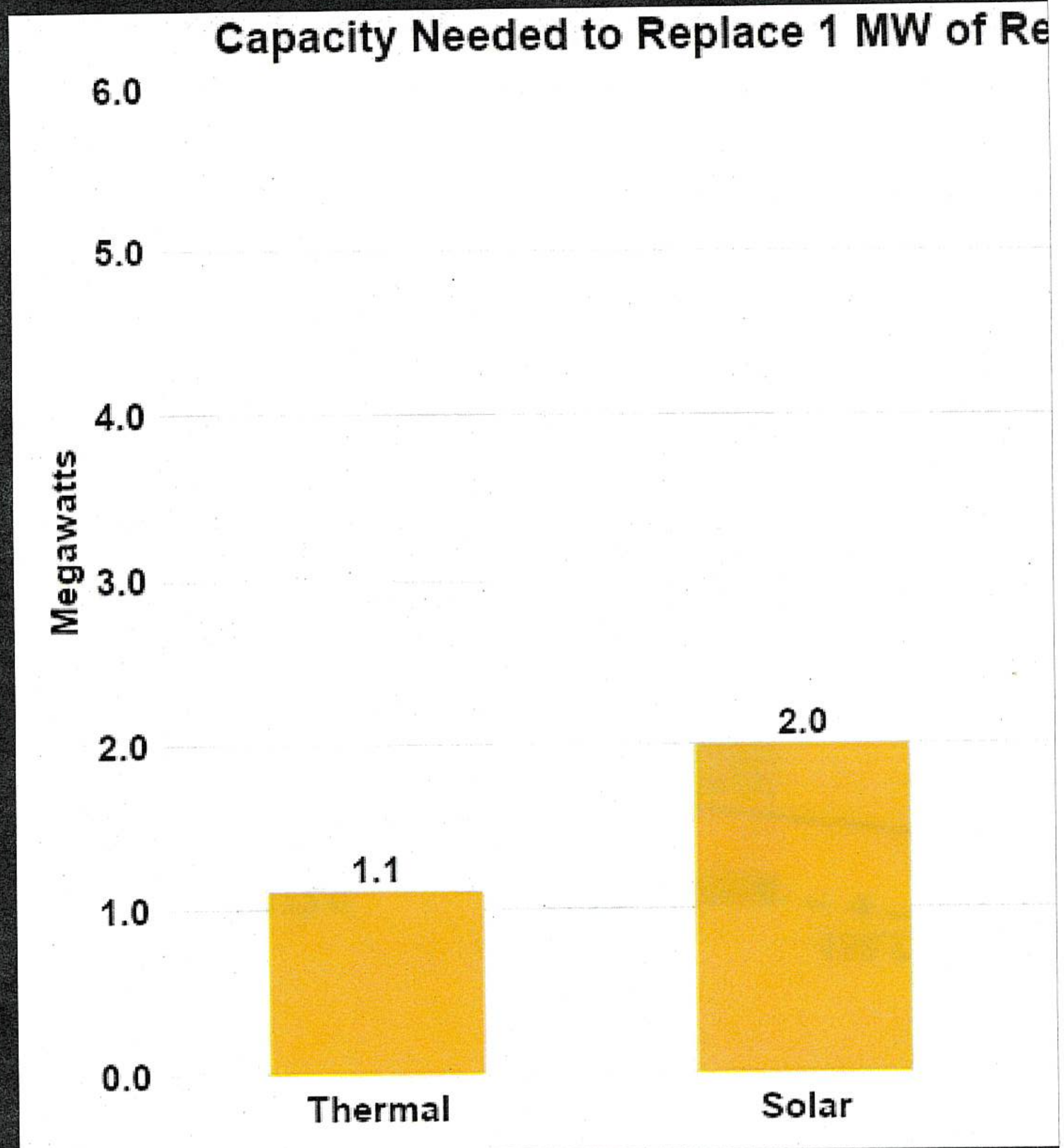
AMERICAN EXPERIMENT

EPA is Assuming Massive Changes to the MISO Grid IRA and Proposed CO_2 Rules



Capacity Needed to Replace 1 MW

- Shutting down 1 MW of coal requires 2 MW of solar to replace it (in theory) and 5.6 MW of wind.
- Solar and wind can't actually replace this capacity, in these increments because sometimes wind and solar produce almost nothing.
- This leads to "overbuilding" to meet demand, which is very expensive.



AMERICAN EXPERIMENT

EPA Makes Unreasonably High Estimates for Wind a Reliability.

- EPA is expecting wind and solar to perform at a high level.
- EPA's assumptions are higher than the assumptions used by MISO.
- It also assumes existing thermal resources perform at higher levels than MISO assumes.

EPA's Proposed 111 Regu	
Resource	EPA's Capacity Ac
Existing Onshore Wind	19
Existing Solar	55
New Onshore Wind	9%-
New Solar	32%-
Existing Thermal	10
Existing Hydro	56
New Hydro	65
Existing Energy Storage	48
Pumped Storage	95
New Battery Storage	10

mparing Highest Certainty Deliverability (HCD) Acc the EPA's Capacity Accreditation

EPA APPROACH

EPA's Proposed 111 Regulations	
Resource	EPA's Capacity Accreditation in MISO
Existing Onshore Wind	19%
Existing Solar	55%
New Onshore Wind	9%-25%
New Solar	32%-52%
Existing Thermal	100%
Existing Hydro	56%
New Hydro	65%
Existing Energy Storage	48%
Pumped Storage	95%
New Battery Storage	100%

HCD APPROA

Highest Certainty Deliv		
Resouce	Peak Accreditation	N A
Wind	7.1%	
Solar	12.4%	
Battery Storage	100.0%	
Thermal	90.0%	
Reserve Margin	16.8%	

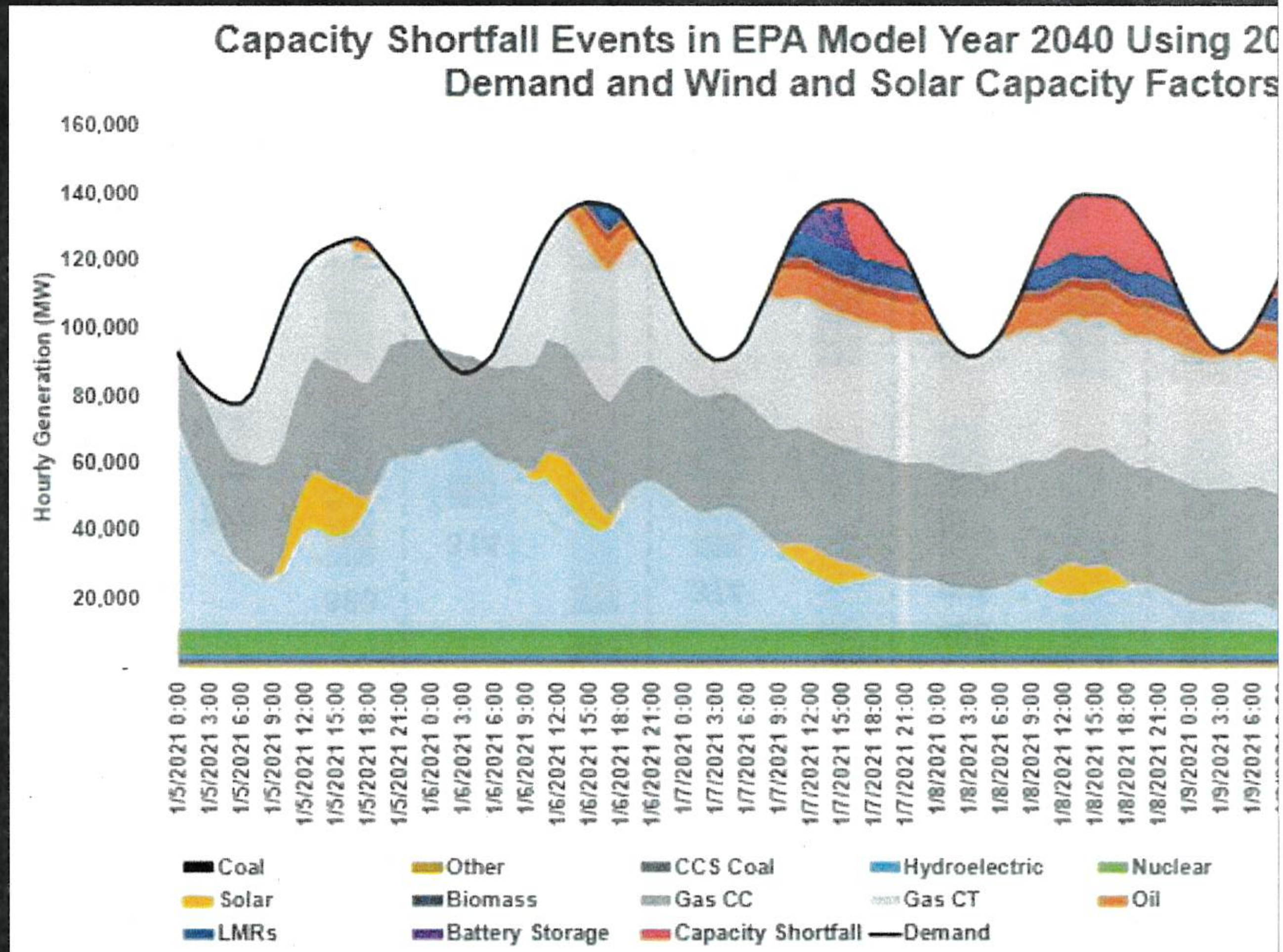
Assessing Reliability Under EPA's Prop

- **EPA did not conduct a reliability assessment of its proposals, so we did it for them.**
- Our analysis compared EPA's assumed generation portfolio to the historical hourly electricity demand and hourly capacity factors for wind and solar in 2019, 2020, 2021, and 2022 to assess whether the installed resources would be able to keep the lights on for all hours of the year.
- Hourly demand and wind and solar capacity factors were adjusted upward to meet EPA's peak load, annual generation, and capacity factor assumptions.
    - This assumption is generous to EPA because it increases the annual output of wind and solar generators to levels that are not generally observed in MISO.
    - Additionally, other policies pursued by the EPA may increase peak load even further, but this additional load was not studied in this analysis.
- Will EPA's modeled grid be able to meet demand based on these observed, real-life model inputs?

AMERICAN EXPERIMENT

Assessing Severity of the Blackouts

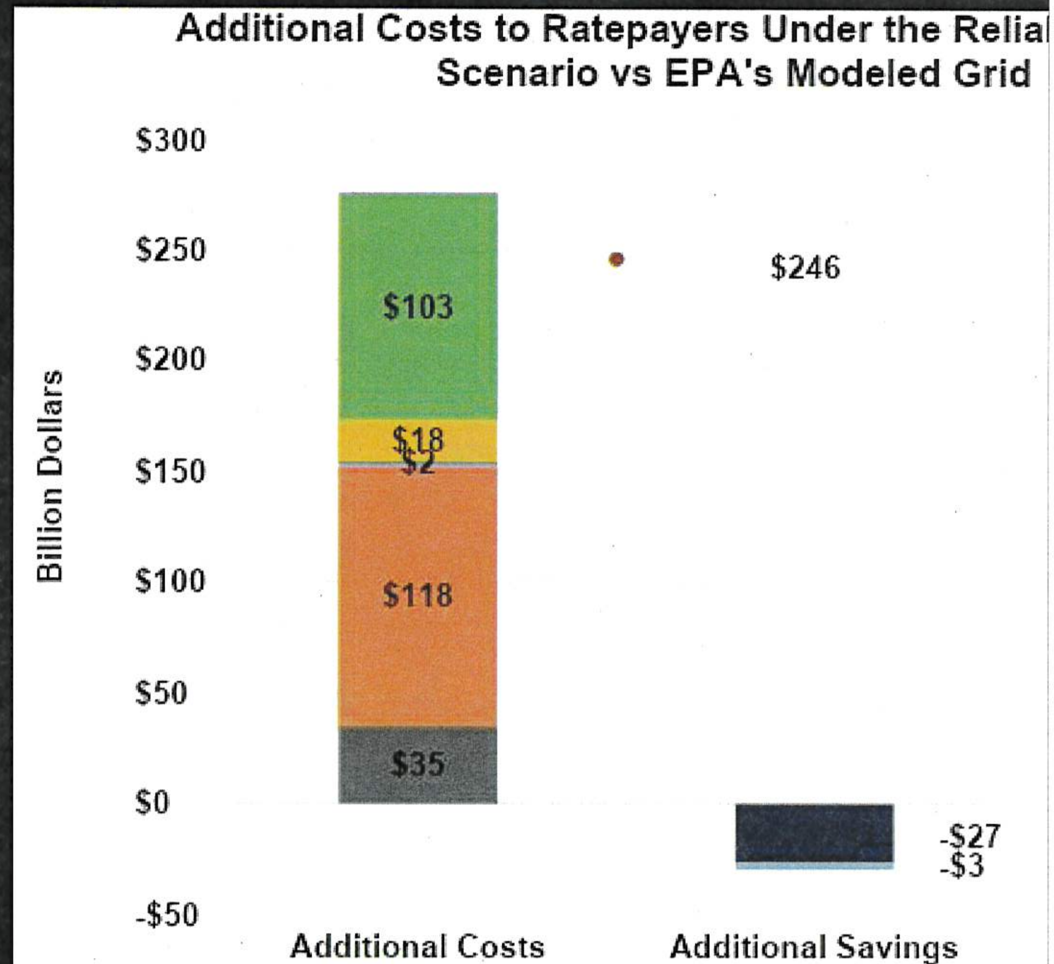
- The worst capacity shortfall is a 26 GW capacity shortfall that would occur in January 2040 using the 2021 HCY, accounting for 19.5 percent of the electricity demand at the time of the shortfall.
- This is the equivalent of needing to implement a blackout 12 minutes out of every hour.



AMERICAN EXPERIMENT

Executive Summary: Shoring Up EPA's Mod Would Cost $246 Billion

- Preventing capacity shortfalls while still meeting EPAs emission targets would require large capacity additions.
- These additions would increase the cost of compliance by $246 billion through 2055, or $7.7 billion annually, compared to the cost of EPA's modeled MISO grid in the Integrated Proposal with LNG Update.
- **This figure exceeds EPA's annual net benefit estimate of $5.9 billion for the entire country.**



AMERICAN EXPERIMENT