No. _____

In the Supreme Court of the United States

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION,
Applicant,

V.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and MICHAEL REGAN, in his official capacity as Administrator of the United States Environmental Protection Agency,
Respondents.

APPENDIX TO
APPLICATION FOR IMMEDIATE STAY OF FINAL AGENCY ACTION PENDING APPELLATE REVIEW

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Appendix 1

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2023–0072; FRL–8536–01–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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing multiple actions under section 111 of the Clean Air Act (CAA) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs). First, the EPA is finalizing the repeal of the Affordable Clean Energy (ACE) Rule. Second, the EPA is finalizing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Third, the EPA is finalizing revisions to the New Source Performance Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Fourth, the EPA is finalizing revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The EPA is not finalizing emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines at this time; instead, the EPA intends to take further action on the proposed emission guidelines at a later date.

DATES: This final rule is effective on July 8, 2024. The incorporation by reference of certain publications listed in the rules is approved by the Director of the Federal Register as of July 8, 2024. The incorporation by reference of certain other materials listed in the rule was approved by the Director of the Federal Register as of October 23, 2015.

ADDRESSES: The EPA has established a docket for these actions under Docket ID No. EPA–HQ–OAR–2023–0072. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Lisa Thompson (she/her), Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5158; and email address: *thompson.lisa@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACE Affordable Clean Energy rule
BSER best system of emissions reduction
Btu British thermal unit
CAA Clean Air Act
CBI Confidential Business Information
CCS carbon capture and sequestration/storage
CCUS carbon capture, utilization, and sequestration/storage
CO_2 carbon dioxide
DER distributed energy resources
DOE Department of Energy
EEA energy emergency alert
EGU electric generating unit
EIA Energy Information Administration
EJ environmental justice
E.O. Executive Order
EPA Environmental Protection Agency
FEED front-end engineering and design
FGD flue gas desulfurization
FR Federal Register
GHG greenhouse gas
GW gigawatt
GWh gigawatt-hour
HAP hazardous air pollutant
HRSG heat recovery steam generator
IIJA Infrastructure Investment and Jobs Act
IRC Internal Revenue Code
kg kilogram
kWh kilowatt-hour
LCOE levelized cost of electricity
LNG liquefied natural gas
MATS Mercury and Air Toxics Standards
MMBtu/h million British thermal units per hour
MMT CO_2e million metric tons of carbon dioxide equivalent
MW megawatt
MWh megawatt-hour
NAAQS National Ambient Air Quality Standards
NESHAP National Emission Standards for Hazardous Air Pollutants
NGCC natural gas combined cycle
NO_X nitrogen oxides
NSPS new source performance standards
NSR New Source Review
PM particulate matter
$PM_{2.5}$ fine particulate matter
RIA regulatory impact analysis
TSD technical support document
U.S. United States

Organization of this document. The information in this preamble is organized as follows:

I. Executive Summary

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare.[1] Since that time, the evidence of the harms posed by GHG emissions has only grown, and Americans experience the destructive and worsening effects of climate change every day.[2] Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2021.[3] At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources is available to the power sector—including carbon capture and sequestration/storage (CCS), co-firing with less GHG-intensive fuels, and more efficient generation. Congress has also acted to provide funding and other incentives to encourage the deployment of various technologies, including CCS, to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is finalizing several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing emission guidelines and new source performance standards (NSPS) that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of CAA section 111, the final NSPS and emission guidelines reflect the application of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

Specifically, the EPA is first finalizing the repeal of the Affordable Clean Energy (ACE) Rule. Second, the EPA is finalizing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Third, the EPA is finalizing revisions to the NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Fourth, the EPA is finalizing revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The EPA is not finalizing emission guidelines for GHG emissions from existing fossil fuel-fired combustion turbines at this time and plans to expeditiously issue an additional proposal that more comprehensively addresses GHG emissions from this portion of the fleet. The EPA acknowledges that the share of GHG emissions from existing fossil fuel-fired combustion turbines has been growing and is projected to continue to do so, particularly as emissions from other portions of the fleet decline, and that it is vital to regulate the GHG emissions from these sources consistent with CAA section 111.

These final actions ensure that the new and existing fossil fuel-fired EGUs that are subject to these rules reduce their GHG emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These standards and emission guidelines will significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and

[1] 74 FR 66496 (December 15, 2009).

[2] The 5th National Climate Assessment (NCA5) states that the effects of human-caused climate change are already far-reaching and worsening across every region of the United States and that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends.

[3] *https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.*

welfare. Further, the EPA has designed these standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

A. Climate Change and Fossil Fuel-Fired EGUs

These final actions reduce the emissions of GHGs from new and existing fossil fuel-fired EGUs. The increasing concentrations of GHGs in the atmosphere are, and have been, warming the planet, resulting in serious and life-threatening environmental and human health impacts. The increased concentrations of GHGs in the atmosphere and the resulting warming have led to more frequent and more intense heat waves and extreme weather events, rising sea levels, and retreating snow and ice, all of which are occurring at a pace and scale that threaten human health and welfare.

Fossil fuel-fired EGUs that are uncontrolled for GHGs are one of the biggest domestic sources of GHG emissions. At the same time, there are technologies available (including technologies that can be applied to fossil fuel-fired power plants) to significantly reduce emissions of GHGs from the power sector. Low- and zero-GHG electricity are also key enabling technologies to significantly reduce GHG emissions in almost every other sector of the economy.

In 2021, the power sector was the largest stationary source of GHGs in the United States, emitting 25 percent of overall domestic emissions.[4] In 2021, existing fossil fuel-fired steam generating units accounted for 65 percent of the GHG emissions from the sector, but only accounted for 23 percent of the total electricity generation.

Because of its outsized contributions to overall emissions, reducing emissions from the power sector is essential to addressing the challenge of climate change—and sources in the power sector also have many available options for reducing their climate-destabilizing emissions. Particularly relevant to these actions are several key technologies (CCS and co-firing of lower-GHG fuels) that allow fossil fuel-fired steam generating EGUs and stationary combustion turbines to provide power while emitting significantly lower GHG emissions. Moreover, with the increased electrification of other GHG-emitting sectors of the economy, such as personal vehicles, heavy-duty trucks, and the heating and cooling of buildings, reducing GHG emissions from these affected sources can also help reduce power sector pollution that might otherwise result from the electrification of other sectors of the economy.

B. Recent Developments in Emissions Controls and the Electric Power Sector

Several recent developments concerning emissions controls are relevant for the EPA's determination of the BSER for existing coal-fired steam generating EGUs and new natural gas-fired stationary combustion turbines. These include lower costs and continued improvements in CCS technology, alongside Federal tax incentives that allow companies to largely offset the cost of CCS. Well-established trends in the sector further inform where using such technologies is cost effective and feasible, and form part of the basis for the EPA's determination of the BSER.

In recent years, the cost of CCS has declined in part because of process improvements learned from earlier deployments and other advances in the technology. In addition, the Inflation Reduction Act (IRA), enacted in 2022, extended and significantly increased the tax credit for carbon dioxide (CO_2) sequestration under Internal Revenue Code (IRC) section 45Q. The provision of tax credits in the IRA, combined with the funding included in the Infrastructure Investment and Jobs Act (IIJA), enacted in 2021, incentivize and facilitate the deployment of CCS and other GHG emission control technologies. As explained later in this preamble, these developments support the EPA's conclusion that CCS is the BSER for certain subcategories of new and existing EGUs because it is an adequately demonstrated and available control technology that significantly reduces emissions of dangerous pollution and because the costs of its installation and operation are reasonable. Some companies have already made plans to install CCS on their units independent of the EPA's regulations.

Well documented trends in the power sector also influence the EPA's determination of the BSER. In particular, CCS entails significant capital expenditures and is only cost-reasonable for units that will operate enough to defray those capital costs. At the same time, many utilities and power generating companies have recently announced plans to accelerate changing the mix of their generating assets. The IIJA and IRA, state legislation, technology advancements, market forces, consumer demand, and the advanced age of much of the existing fossil fuel-fired generating fleet are collectively leading to, in most cases, decreased use of the fossil fuel-fired units that are the subjects of these final actions. From 2010 through 2022, fossil fuel-fired generation declined from approximately 72 percent of total net generation to approximately 60 percent, with generation from coal-fired sources dropping from 49 percent to 20 percent of net generation during this period.[5] These trends are expected to continue and are relevant to determining where capital-intensive technologies, like CCS, may be feasibly and cost-reasonably deployed to reduce emissions.

Congress has taken other recent actions to drive the reduction of GHG emissions from the power sector. As noted earlier, Congress enacted IRC section 45Q in section 115 of the Energy Improvement and Extension Act of 2008 to provide a tax credit for the sequestration of CO_2. Congress significantly amended IRC section 45Q in the Bipartisan Budget Act of 2018, and more recently in the IRA, to make this tax incentive more generous and effective in spurring long-term deployment of CCS. In addition, the IIJA provided more than $65 billion for infrastructure investments and upgrades for transmission capacity, pipelines, and low-carbon fuels.[6] Further, the Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS Act) authorized billions more in funding for development of low- and non-GHG emitting energy technologies that could provide additional low-cost options for power companies to reduce overall GHG emissions.[7] As discussed in greater detail in section IV.E.1 of this preamble, the IRA, the IIJA, and CHIPS contain numerous other provisions encouraging companies to reduce their GHGs.

C. Summary of the Principal Provisions of These Regulatory Actions

These final actions include the repeal of the ACE Rule, BSER determinations and emission guidelines for existing fossil fuel-fired steam generating units, and BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines and modified fossil fuel-fired steam generating units.

[4] *https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.*

[5] U.S. Energy Information Administration (EIA). Electric Power Annual. 2010 and 2022. *https://www.eia.gov/electricity/annual/html/epa_03_01_a.html.*

[6] *https://www.congress.gov/bill/117th-congress/house-bill/3684.*

[7] *https://www.congress.gov/bill/117th-congress/house-bill/4346.*

The EPA is taking these actions consistent with its authority under CAA section 111. Under CAA section 111, once the EPA has identified a source category that contributes significantly to dangerous air pollution, it proceeds to regulate new sources and, for GHGs and certain other air pollutants, existing sources. 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.[8] The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER and may subcategorize sources accordingly.

Once it identifies the BSER, the EPA must determine the ''degree of emission limitation'' achievable by application of the BSER. For new sources, the EPA establishes the standard of performance with which the sources must comply, which is a standard for emissions that reflects the degree of emission limitation. For existing sources, the EPA includes the information it has developed concerning the BSER and associated degree of emission limitation in emission guidelines and directs the states to adopt state plans that contain standards of performance that are consistent with the emission guidelines.

Since the early 1970s, the EPA has promulgated regulations under CAA section 111 for more than 60 source categories, which has established a robust set of regulatory precedents that has informed the development of these final actions. During this period, the courts, primarily the U.S. Court of Appeals for the D.C. Circuit and the Supreme Court, have developed a body of caselaw interpreting CAA section 111. As the Supreme Court has recognized, the EPA has typically (and does so in these actions) determined the BSER to be ''measures that improve the pollution performance of individual sources,'' such as add-on controls and clean fuels. *West Virginia* v. *EPA*, 597 U.S. 697, 734 (2022). For present purposes, several of a BSER's key features include that it must reduce emissions, be based on ''adequately demonstrated'' technology, and have a reasonable cost of control. The case law interpreting section 111 has also recognized that the BSER can be forward-looking in nature and take into account anticipated improvements in control technologies. For example, the EPA may determine a control to be ''adequately demonstrated'' even if it is new and not yet in widespread commercial use, and, further, that the EPA may reasonably project the development of a control system at a future time and establish requirements that take effect at that time. Further, the most relevant costs under CAA section 111 are the costs to the regulated facility. The actions that the EPA is finalizing are consistent with the requirements of CAA section 111 and its regulatory history and caselaw, which is discussed in further detail in section V of this preamble.

1. Repeal of ACE Rule

The EPA is finalizing its proposed repeal of the existing ACE Rule emission guidelines. First, as a policy matter, the EPA concludes that the suite of heat rate improvements (HRI) that was identified in the ACE Rule as the BSER is not an appropriate BSER for existing coal-fired EGUs. Second, the ACE Rule rejected CCS and natural gas co-firing as the BSER for reasons that no longer apply. Third, the EPA concludes that the ACE Rule conflicted with CAA section 111 and the EPA's implementing regulations because it did not provide sufficient specificity as to the BSER the EPA had identified or the ''degree of emission limitation achievable though application of the [BSER].''

Also, the EPA is withdrawing the proposed revisions to the New Source Review (NSR) regulations that were included the ACE Rule proposal (83 FR 44773–83; August 31, 2018).

2. Emission Guidelines for Existing Fossil Fuel-Fired Steam Generating Units

The EPA is finalizing CCS with 90 percent capture as BSER for existing coal-fired steam generating units. These units have a presumptive standard[9] of an 88.4 percent reduction in annual emission rate, with a compliance deadline of January 1, 2032. As explained in detail below, CCS is an adequately demonstrated technology that achieves significant emissions reduction and is cost-reasonable, taking into account the declining costs of the technology and a substantial tax credit available to sources. In recognition of the significant capital expenditures involved in deploying CCS technology and the fact that 45 percent of regulated units already have announced retirement dates, the EPA is finalizing a separate subcategory for existing coal-fired steam generating units that demonstrate that they plan to permanently cease operation before January 1, 2039. The BSER for this subcategory is co-firing with natural gas, at a level of 40 percent of the unit's annual heat input. These units have a presumptive standard of 16 percent reduction in annual emission rate corresponding to this BSER, with a compliance deadline of January 1, 2030.

The EPA is finalizing an applicability exemption for existing coal-fired steam EGUs demonstrating that they plan to permanently cease operation prior to January 1, 2032, based on the Agency's determination that units retiring before this date generally do not have cost-reasonable options for improving their GHG emissions performance. Sources that demonstrate they will permanently cease operation before this applicability deadline will not be subject to these emission guidelines. Further, the EPA is not finalizing the proposed imminent-term or near-term subcategories.

The EPA is finalizing the proposed structure of the subcategory definitions for natural gas- and oil-fired steam generating units. The EPA is also finalizing routine methods of operation and maintenance as the BSER for intermediate load and base load natural gas- and oil-fired steam generating units. Furthermore, the EPA is finalizing presumptive standards for natural gas- and oil-fired steam generating units that are slightly higher than at proposal: base load sources (those with annual capacity factors greater than 45 percent) have a presumptive standard of 1,400 lb CO_2/MWh-gross, and intermediate load sources (those with annual capacity factors greater than 8 percent and less than or equal to 45 percent) have a presumptive standard of 1,600 lb CO_2/MWh-gross. For low load (those with annual capacity factors less than 8 percent), the EPA is finalizing a uniform fuels BSER and a presumptive input-based standard of 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources.

3. Standards of Performance for New and Reconstructed Fossil Fuel-Fired Combustion Turbines

The EPA is finalizing emission standards for three subcategories of combustion turbines—base load, intermediate load, and low load. The BSER for base load combustion turbines includes two components to be implemented initially in two phases. The first component of the BSER for base load combustion turbines is highly efficient generation (based on the emission rates that the best performing

[8] CAA section 111(a)(1).

[9] Presumptive standards of performance are discussed in detail in section X of the preamble. While states establish standards of performance for sources, the EPA provides presumptively approvable standards of performance based on the degree of emission limitation achievable through application of the BSER for each subcategory.

units are achieving) and the second component for base load combustion turbines is utilization of CCS with 90 percent capture. Recognizing the lead time that is necessary for new base load combustion turbines to plan for and install the second component of the BSER (*i.e.*, 90 percent CCS), including the time that is needed to deploy the associated infrastructure (CO_2 pipelines, storage sites, *etc.*), the EPA is finalizing a second phase compliance deadline of January 1, 2032, for this second component of the standard.

The EPA has identified highly efficient simple cycle generation as the BSER for intermediate load combustion turbines. For low load combustion turbines, the EPA is finalizing its proposed determination that the BSER is the use of lower-emitting fuels.

4. New, Modified, and Reconstructed Fossil Fuel-Fired Steam Generating Units

The EPA is finalizing revisions of the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.*, a modification that increases its hourly emission rate by more than 10 percent) to mirror the emission guidelines for existing coal-fired steam generators. This reflects the EPA's determination that such modified sources are capable of meeting the same presumptive standards that the EPA is finalizing for existing steam EGUs. Further, this revised standard for modified coal-fired steam EGUs will avoid creating an unjustified disparity between emission control obligations for modified and existing coal-fired steam EGUs.

The EPA did not propose, and we are not finalizing, any review or revision of the 2015 standard for large modifications of oil- or gas-fired steam generating units because we are not aware of any existing oil- or gas-fired steam generating EGUs that have undertaken such modifications or have plans to do so, and, unlike an existing coal-fired steam generating EGUs, existing oil- or gas-fired steam units have no incentive to undertake such a modification to avoid the requirements we are including in this final rule for existing oil- or gas-fired steam generating units.

As discussed in the proposal preamble, the EPA is not revising the NSPS for newly constructed or reconstructed fossil fuel-fired steam electric generating units (EGU) at this time because the EPA anticipates that few, if any, such units will be constructed or reconstructed in the foreseeable future. However, the EPA has recently become aware that a new coal-fired power plant is under consideration in Alaska. Accordingly, the EPA is not, at this time, finalizing its proposal not to review the 2015 NSPS, and, instead, will continue to consider whether to review the 2015 NSPS. As developments warrant, the EPA will determine either to conduct a review, and propose revised standards of performance, or not conduct a review.

Also, in this final action, the EPA is withdrawing the 2018 proposed amendments [10] to the NSPS for GHG emissions from coal-fired EGUs.

5. Severability

This final action is composed of four independent rules: the repeal of the ACE rule; GHG emission guidelines for existing fossil fuel-fired steam generating units; NSPS for GHG emissions from new and reconstructed fossil fuel-fired combustion turbines; and revisions to the standards of performance for new, modified, and reconstructed fossil fuel-fired steam generating units. The EPA could have finalized each of these rules in separate **Federal Register** notices as separate final actions. The Agency decided to include these four independent rules in a single **Federal Register** notice for administrative ease because they all relate to climate pollution from the fossil fuel-fired electric generating units source category. Accordingly, despite grouping these rules into one single **Federal Register** notice, the EPA intends that each of these rules described in sections I.C.1 through I.C.4 is severable from the other.

In addition, each rule is severable as a practical matter. For example, the EPA would repeal the ACE Rule separate and apart from finalizing new standards for these sources as explained herein. Moreover, the BSER and associated emission guidelines for existing fossil fuel-fired steam generating units are independent of and would have been the same regardless of whether the EPA finalized the other parts of this rule. In determining the BSER for existing fossil fuel-fired steam generating units, the EPA considered only the technologies available to reduce GHG emissions at those sources and did not take into consideration the technologies or standards of performance for new fossil fuel-fired combustion turbines. The same is true for the Agency's evaluation and determination of the BSER and associated standards of performance for new fossil fuel-fired combustion turbines. The EPA identified the BSER and established the standards of performance by examining the controls that were available for these units. That analysis can stand alone and apart from the EPA's separate analysis for existing fossil fuel-fired steam generating units. Though the record evidence (including, for example, modeling results) often addresses the availability, performance, and expected implementation of the technologies at both existing fossil fuel-fired steam generating units and new fossil fuel-fired combustion turbines in the same record documents, the evidence for each evaluation stands on its own, and is independently sufficient to support each of the final BSERs.

In addition, within section I.C.1, the final action to repeal the ACE Rule is severable from the withdrawal of the NSR revisions that were proposed in parallel with the ACE Rule proposal. Within the group of actions for existing fossil fuel-fired steam generating units in section I.C.2, the requirements for each subcategory of existing sources are severable from the requirements for each other subcategory of existing sources. For example, if a court were to invalidate the BSER and associated emission standard for units in the medium-term subcategory, the BSER and associated emission standard for units in the long-term subcategory could function sensibly because the effectiveness of the BSER for each subcategory is not dependent on the effectiveness of the BSER for other subcategories. Within the group of actions for new and reconstructed fossil fuel-fired combustion turbines in section I.C.3, the following actions are severable: the requirements for each subcategory of new and reconstructed turbines are severable from the requirements for each other subcategory; and within the subcategory for base load turbines, the requirements for each of the two components are severable from the requirements for the other component. Each of these standards can function sensibly without the others. For example, the BSER for low load, intermediate load, and base load subcategories is based on the technologies the EPA determined met the statutory standards for those subcategories and are independent from each other. And in the base load subcategory units may practically be constructed using the most efficient technology without then installing CCS and likewise may install CCS on a turbine system that was not constructed with the most efficient technology. Within the group of actions for new, modified, and reconstructed fossil fuel-fired steam generating units in section I.C.4, the revisions of the standards of performance for coal-fired steam

[10] See 83 FR 65424, December 20, 2018.

generators that undertake a large modification are severable from the withdrawal of the 2018 proposal to revise the NSPS for emissions of GHG from EGUs. Each of the actions in these final rules that the EPA has identified as severable is functionally independent—*i.e.*, may operate in practice independently of the other actions.

In addition, while the EPA is finalizing this rule at the same time as other final rules regulating different types of pollution from EGUs—specifically the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (FR 2024–09815, EPA–HQ–OW–2009–0819; FRL–8794–02–OW); National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (FR 2024–09148, EPA–HQ–OAR–2018–0794; FRL–6716.3–02–OAR); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments (FR 2024–09157, EPA–HQ–OLEM–2020–0107; FRL–7814–04–OLEM)—and has considered the interactions between and cumulative effects of these rules, each rule is based on different statutory authority, a different record, and is completely independent of the other rules.

D. Grid Reliability Considerations

The EPA is finalizing multiple adjustments to the proposed rules that ensure the requirements in these final actions can be implemented without compromising the ability of power companies, grid operators, and state and Federal energy regulators to maintain resource adequacy and grid reliability. In response to the May 2023 proposed rule, the EPA received extensive comments from balancing authorities, independent system operators and regional transmission organizations, state regulators, power companies, and other stakeholders on the need for the final rule to accommodate resource adequacy and grid reliability needs. The EPA also engaged with the balancing authorities that submitted comments to the docket, the staff and Commissioners of the Federal Energy Regulatory Commission (FERC), the Department of Energy (DOE), the North American Electric Reliability Corporation (NERC), and other expert entities during the course of this rulemaking. Finally, at the invitation of FERC, the EPA participated in FERC's Annual Reliability Technical Conference on November 9, 2023.

These final actions respond to this input and feedback in multiple ways, including through changes to the universe of affected sources, longer compliance timeframes for CCS implementation, and other compliance flexibilities, as well as articulation of the appropriate use of RULOF to address reliability issues during state plan development and in subsequent state plan revisions. In addition to these adjustments, the EPA is finalizing several programmatic mechanisms specifically designed to address reliability concerns raised by commenters. For existing fossil fuel-fired EGUs, a short-term reliability emergency mechanism is available for states to provide more flexibility by using an alternative emission limitation during acute operational emergencies when the grid might be temporarily under heavy strain. A similar short-term reliability emergency mechanism is also available to new sources. In addition, the EPA is creating an option for states to provide for a compliance date extension for existing sources of up to 1 year under certain circumstances for sources that are installing control technologies to comply with their standards of performance. Lastly, states may also provide, by inclusion in their state plans, a reliability assurance mechanism of up to 1 year that under limited circumstances would allow existing units that had planned to cease operating by a certain date to temporarily remain available to support reliability. Any extensions exceeding 1 year must be addressed through a state plan revision. In order to utilize this reliability pathway, there must be an adequate demonstration of need and certification by a reliability authority, and approval by the appropriate EPA Regional Administrator. The EPA plans to seek the advice of FERC for extension requests exceeding 6 months. Similarly, for new fossil fuel-fired combustion turbines, the EPA is creating a mechanism whereby baseload units may request a 1-year extension of their CCS compliance deadline under certain circumstances.

The EPA has evaluated the resource adequacy implications of these actions in the final technical support document (TSD), *Resource Adequacy Analysis*, and conducted capacity expansion modeling of the final rules in a manner that takes into account resource adequacy needs. The EPA finds that resource adequacy can be maintained with the final rules. The EPA modeled a scenario that complies with the final rules and that meets resource adequacy needs. The EPA also performed a variety of other sensitivity analyses looking at higher electricity demand (load growth) and impact of the EPA's additional regulatory actions affecting the power sector. These sensitivity analyses indicate that, in the context of higher demand and other pending power sector rules, the industry has available pathways to comply with this rule that respect NERC reliability considerations and constraints.

In addition, the EPA notes that significant planning and regulatory mechanisms exist to ensure that sufficient generation resources are available to maintain reliability. The EPA's consideration of reliability in this rulemaking has also been informed by consultation with the DOE under the auspices of the March 9, 2023, memorandum of understanding (MOU)[11] signed by the EPA Administrator and the Secretary of Energy, as well as by consultation with FERC expert staff. In these final actions, the EPA has included various flexibilities that allow power companies and grid operators to plan for achieving feasible and necessary reductions of GHGs from affected sources consistent with the EPA's statutory charge while ensuring that the rule will not interfere with systems operators' ability to ensure grid reliability.

A thorough description of how adjustments in the final rules address reliability issues, the EPA's outreach to balancing authorities, EPA's supplemental notice, as well as the introduction of mechanisms to address short- and long-term reliability needs is presented in section XII.F of this preamble.

E. Environmental Justice Considerations

Consistent with Executive Order (E.O.) 14096, and the EPA's commitment to upholding environmental justice (EJ) across its policies and programs, the EPA carefully considered the impacts of these actions on communities with environmental justice concerns. As part of the regulatory development process for these rulemakings, and consistent with directives set forth in multiple Executive Orders, the EPA conducted extensive outreach with interested parties including Tribal nations and communities with environmental justice concerns. These opportunities gave the EPA a chance to hear directly from the public, including from communities potentially impacted by these final

[11] *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* (March 9, 2023). *https://www.epa.gov/power-sector/electric-reliability-mou.*

actions. The EPA took this feedback into account in its development of these final actions.[12] The EPA's analysis of environmental justice in these final actions is briefly summarized here and discussed in further detail in sections XII.E and XIII.J of the preamble and section 6 of the regulatory impact analysis (RIA).

Several environmental justice organizations and community representatives raised significant concerns about the potential health, environmental, and safety impacts of CCS. The EPA takes these concerns seriously, agrees that any impacts to historically disadvantaged and overburdened communities are important to consider, and has carefully considered these concerns as it finalized its determinations of the BSERs for these rules. The Agency acknowledges that while these final actions will result in large reductions of both GHGs and other emissions that will have significant positive benefits, there is the potential for localized increases in emissions, particularly if units installing CCS operate for more hours during the year and/or for more years than they would have otherwise. However, as discussed in section VII.C.1.a.iii(B), a robust regulatory framework exists to reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. The Council on Environmental Quality's (CEQ) February 2022 *Carbon Capture, Utilization, and Sequestration Guidance* and the EPA's evaluation of BSER recognize that multiple Federal agencies have responsibility for regulating and permitting CCS projects, along with state and tribal governments. As the CEQ has noted, Federal agencies have "taken actions in the past decade to develop a robust carbon capture, utilization, and sequestration/storage (CCUS) regulatory framework to protect the environment and public health across multiple statutes."[13 14]

Furthermore, the EPA plans to review and update as needed its guidance on NSR permitting, specifically with respect to BACT determinations for GHG emissions and consideration of co-pollutant increases from sources installing CCS. For the reasons explained in section VII.C, the EPA is finalizing the determination that CCS is the BSER for certain subcategories of new and existing EGUs based on its consideration of all of the statutory criteria for BSER, including emission reductions, cost, energy requirements, and non-air health and environmental considerations. At the same time, the EPA recognizes the critical importance of ensuring that the regulatory framework performs as intended to protect communities.

These actions are focused on establishing NSPS and emission guidelines for GHGs that states will implement to significantly reduce GHGs and move us a step closer to avoiding the worst impacts of climate change, which is already having a disproportionate impact on communities with environmental justice concerns. The EPA analyzed several illustrative scenarios representing potential compliance outcomes and evaluated the potential impacts that these actions may have on emissions of GHG and other health-harming air pollutants from fossil fuel-fired EGUs, as well as how these changes in emissions might affect air quality and public health, particularly for communities with EJ concerns.

The EPA's national-level analysis of emission reduction and public health impacts, which is documented in section 6 of the RIA and summarized in greater detail in section XII.A and XII.D of this preamble, finds that these actions achieve nationwide reductions in EGU emissions of multiple health-harming air pollutants including nitrogen oxides (NO_X), sulfur dioxide (SO_2), and fine particulate matter ($PM_{2.5}$), resulting in public health benefits. The EPA also evaluated how the air quality impacts associated with these final actions are distributed, with particular focus on communities with EJ concerns. As discussed in the RIA, our analysis indicates that baseline ozone and $PM_{2.5}$ concentration will decline substantially relative to today's levels. Relative to these low baseline levels, ozone and $PM_{2.5}$ concentrations will decrease further in virtually all areas of the country, although some areas of the country may experience slower or faster rates of decline in ozone and $PM_{2.5}$ pollution over time due to the changes in generation and utilization resulting from these rules. Additionally, our comparison of future air quality conditions with and without these rules suggests that while these actions are anticipated to lead to modest but widespread reductions in ambient levels of $PM_{2.5}$ and ozone for a large majority of the nation's population, there is potential for some geographic areas and demographic groups to experience small increases in ozone concentrations relative to the baseline levels which are projected to be substantially lower than today's levels.

It is important to recognize that while these projections of emissions changes and resulting air quality changes under various illustrative compliance scenarios are based upon the best information available to the EPA at this time, with regard to existing sources, each state will ultimately be responsible for determining the future operation of fossil fuel-fired steam generating units located within its jurisdiction. The EPA expects that, in making these determinations, states will consider a number of factors and weigh input from the wide range of potentially affected stakeholders. The meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders—including community members adversely impacted by pollution, energy workers affected by construction and/or other changes in operation at fossil-fuel-fired power plants, consumers and other interested parties—will have an opportunity to have their concerns heard as states make decisions balancing a multitude of factors including appropriate standards of performance, compliance strategies, and compliance flexibilities for existing EGUs, as well as public health and environmental considerations. The EPA believes that these provisions, together with the protections referenced above, can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

F. Energy Workers and Communities

These final actions include requirements for meaningful engagement in development of state plans, including with energy workers and communities. These communities, including energy workers employed at affected EGUs, workers who may construct and install pollution control technology, workers employed by fuel extraction and delivery, organizations

[12] Specifically, the EPA has relied on, and is incorporating as a basis for this rulemaking, analyses regarding possible adverse environmental effects from CCS, including those highlighted by commenters. Consideration of these effects is permissible under CAA section 111(a)(1). Although the EPA also conducted analyses of disproportionate impacts pursuant to E.O. 14096, see section XII.E, the EPA did not consider or rely on these analyses as a basis for these rules.

[13] 87 FR 8808, 8809 (February 16, 2022).

[14] This framework includes, among other things, the EPA regulation of geologic sequestration wells under the Underground Injection Control (UIC) program of the Safe Drinking Water Act; required reporting and public disclosure of geologic sequestration activity, as well as implementation of rigorous monitoring, reporting, and verification of geologic sequestration under the EPA's Greenhouse Gas Reporting Program (GHGRP); and safety regulations for CO_2 pipelines administered by the Pipeline and Hazardous Materials and Safety Administration (PHMSA).

representing these workers, and communities living near affected EGUs, are impacted by power sector trends on an ongoing basis and by these final actions, and the EPA expects that states will include these stakeholders as part of their constructive engagement under the requirements in this rule.

The EPA consulted with the Federal Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Energy Communities IWG) in development of these rules and the meaningful engagement requirements. The EPA notes that the Energy Communities IWG has provided resources to help energy communities access the expanded federal resources made available by the Bipartisan Infrastructure Law, CHIPS and Science Act, and Inflation Reduction Act, many of which are relevant to the development of state plans.

G. Key Changes From Proposal

The key changes from proposal in these final actions are: (1) the reduction in number of subcategories for existing coal-fired steam generating units, (2) the extension of the compliance date for existing coal-fired steam generating units to meet a standard of performance based on implementation of CCS, (3) the removal of low-GHG hydrogen co-firing as a BSER pathway, and (4) the addition of two reliability-related instruments. In addition, (5), the EPA is not finalizing proposed requirements for existing fossil fuel-fired stationary combustion turbines at this time.

The reduction in number of subcategories for existing coal-fired steam generating units: The EPA proposed four subcategories for existing coal-fired steam generating units, which would have distinguished these units by operating horizon and by load level. These included subcategories for existing coal-fired EGUs planning to cease operations in the imminent-term (*i.e.*, prior to January 1, 2032) and those planning to cease operations in the near-term (*i.e.*, prior to January 1, 2035). While commenters were generally supportive of the proposed subcategorization approach, some requested that the cease-operation-by date for the imminent-term subcategory be extended and the utilization limit for the near-term subcategory be relaxed. The EPA is not finalizing the imminent-term and near-term subcategories of coal-fired steam generating units. Rather, the EPA is finalizing an applicability exemption for coal-fired steam generating units demonstrating that they plan to permanently cease operation before January 1, 2032. See section VII.B of this preamble for further discussion.

The extension of the compliance date for existing coal-fired steam generating units to meet a standard of performance based on implementation of CCS. The EPA proposed a compliance date for implementation of CCS for long-term coal-fired steam generating units of January 1, 2030. The EPA received comments asserting that this deadline did not provide adequate lead time. In consideration of those comments, and the record as a whole, the EPA is finalizing a CCS compliance date of January 1, 2032 for these sources.

The removal of low-GHG hydrogen co-firing as a BSER pathway and only use of low-GHG hydrogen as a compliance option: The EPA is not finalizing its proposed BSER pathway of low-GHG hydrogen co-firing for new and reconstructed base load and intermediate load combustion turbines in accordance with CAA section 111(a)(1). The EPA is also not finalizing its proposed requirement that only low-GHG hydrogen may be co-fired in a combustion turbine for the purpose of compliance with the standards of performance. These decisions are based on uncertainties identified for specific criteria used to evaluate low-GHG hydrogen co-firing as a potential BSER, and after further analysis in response to public comments, the EPA has determined that these uncertainties prevent the EPA from concluding that low-GHG hydrogen co-firing is a component of the "best" system of emission reduction at this time. Under CAA section 111, the EPA establishes standards of performance but does not mandate use of any particular technology to meet those standards. Therefore, certain sources may elect to co-fire hydrogen for compliance with the final standards of performance, even absent the technology being a BSER pathway.[15] See section VIII.F.5 of this preamble for further discussion.

The addition of two reliability-related instruments: Commenters expressed concerns that these rules, in combination with other factors, may affect the reliability of the bulk power system. In response to these comments the EPA engaged extensively with balancing authorities, power companies, reliability experts, and regulatory authorities responsible for reliability to inform its decisions in these final rules. As described later in this preamble, the EPA has made adjustments in these final rules that will support power companies, grid operators, and states in maintaining the reliability of the electric grid during the implementation of these final rules. In addition, the EPA has undertaken an analysis of the reliability and resource adequacy implications of these final rules that supports the Agency's conclusion that these final rules can be implemented without adverse consequences for grid reliability. Further, the EPA is finalizing two reliability-related instruments as an additional layer of safeguards for reliability. These instruments include a reliability mechanism for short-term emergency issues, and a reliability assurance mechanism, or compliance flexibility, for units that have chosen compliance pathways with enforceable retirement dates, provided there is a documented and verified reliability concern. In addition, the EPA is finalizing compliance extensions for unanticipated delays with control technology implementation. Specifically, as described in greater detail in section XII.F of this preamble, the EPA is finalizing the following features and changes from the proposal that will provide even greater certainty that these final rules are sensitive to reliability-related issues and constructed in a manner that does not interfere with grid operators' responsibility to deliver reliable power:

(1) longer compliance timelines for existing coal-fired steam generating units;

(2) a mechanism to extend compliance timelines by up to 1 year in the case of unforeseen circumstances, outside of an owner/operator's control, that delay the ability to apply controls (*e.g.*, supply chain challenges or permitting delays);

(3) transparent unit-specific compliance information for EGUs that will allow grid operators to plan for system changes with greater certainty and precision;

(4) a short-term reliability mechanism to allow affected EGUs to operate at

[15] The EPA is not placing qualifications on the type of hydrogen a source may elect to co-fire at this time (see section VIII.F.6.a of this preamble for further discussion). The Agency continues to recognize that even though the combustion of hydrogen is zero-GHG emitting, its production can entail a range of GHG emissions, from low to high, depending on the production method. Thus, even though the EPA is not finalizing the low-GHG hydrogen co-firing as a BSER, as proposed, it maintains that the overall GHG profile of a particular method of hydrogen production should be a primary consideration for any source that decides to co-fire hydrogen to ensure that overall GHG reductions and important climate benefits are achieved. The EPA also notes the anticipated final rule from the U.S. Department of the Treasury pertaining to clean hydrogen production tax and energy credits, which in its proposed form contains certain eligibility parameters, as well as programs administered by the U.S. Department of Energy, such as the recent H2Hubs selections.

baseline emission rates during documented reliability emergencies; and

(5) a reliability assurance mechanism to allow states to delay cease operation dates by up to 1 year in cases where the planned cease operation date is forecast to disrupt system reliability.

Not finalizing proposed requirements for existing fossil fuel-fired stationary combustion turbines at this time: The EPA proposed emission guidelines for large (*i.e.*, greater than 300 MW), frequently operated (*i.e.*, with an annual capacity factor of greater than 50 percent), existing fossil fuel-fired stationary combustion turbines. The EPA received a wide range of comments on the proposed guidelines. Multiple commenters suggested that the proposed provisions would largely result in shifting of generation away from the most efficient natural gas-fired turbines to less efficient natural gas-fired turbines. Commenters stated that, as emissions from coal-fired steam generating units decreased, existing natural gas-fired EGUs were poised to become the largest source of GHG emissions in the power sector. Commenters noted that these units play an important role in grid reliability, particularly as aging coal-fired EGUs retire. Commenters further noted that the existing fossil fuel-fired stationary combustion turbines that were not covered by the proposal (*i.e.*, the smaller and less frequently operating units) are often less efficient, less well controlled for other pollutants such as NO_X, and are more likely to be located near population centers and communities with environmental justice concerns.

The EPA agrees with commenters who observed that GHG emissions from existing natural gas-fired stationary combustion turbines are a growing portion of the emissions from the power sector. This is consistent with EPA modeling that shows that by 2030 these units will represent the largest portion of GHG emissions from the power sector. The EPA agrees that it is vital to promulgate emission guidelines to address GHG emissions from these sources, and that the EPA has a responsibility to do so under section 111(d) of the Clean Air Act. The EPA also agrees with commenters who noted that focusing only on the largest and most frequently operating units, without also addressing emissions from other units, as the May 2023 proposed rule provided, may not be the most effective way to address emissions from this sector. The EPA's modeling shows that over time as the power sector comes closer to reaching the phase-out threshold of the clean electricity incentives in the Inflation Reduction Act (IRA) (*i.e.*, a 75 percent reduction in emissions from the power sector from 2022 levels), the average capacity factor for existing natural gas-fired stationary combustion turbines decreases. Therefore, the EPA's proposal to focus only on the largest units with the highest capacity factors may not be the most effective policy design for reducing GHG emissions from these sources.

Recognizing the importance of reducing emissions from all fossil fuel-fired EGUs, the EPA is not finalizing the proposed emission guidelines for certain existing fossil fuel-fired stationary combustion turbines at this time. Instead, the EPA intends to issue a new, more comprehensive proposal to regulate GHGs from existing sources. The new proposal will focus on achieving greater emission reductions from existing stationary combustion turbines—which will soon be the largest stationary sources of GHG emissions—while taking into account other factors including the local non-GHG impacts of gas turbine generation and the need for reliable, affordable electricity.

II. General Information

A. Action Applicability

The source category that is the subject of these actions is composed of fossil fuel-fired electric utility generating units. The North American Industry Classification System (NAICS) codes for the source category are 221112 and 921150. The list of categories and NAICS codes is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that these final actions are likely to affect.

Final amendments to 40 CFR part 60, subpart TTTT, are directly applicable to affected facilities that began construction after January 8, 2014, but before May 23, 2023, and affected facilities that began reconstruction or modification after June 18, 2014, but before May 23, 2023. The NSPS codified in 40 CFR part 60, subpart TTTTa, is directly applicable to affected facilities that begin construction, reconstruction, or modification on or after May 23, 2023. Federal, state, local, and tribal government entities that own and/or operate EGUs subject to 40 CFR part 60, subpart TTTT or TTTTa, are affected by these amendments and standards.

The emission guidelines codified in 40 CFR part 60, subpart UUUUb, are for states to follow in developing, submitting, and implementing state plans to establish performance standards to reduce emissions of GHGs from designated facilities that are existing sources. Section 111(a)(6) of the CAA defines an ''existing source'' as ''any stationary source other than a new source.'' Therefore, the emission guidelines would not apply to any EGUs that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT. Under the Tribal Authority Rule (TAR), eligible tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a tribal implementation plan (TIP) implementing the emission guidelines codified in 40 CFR part 60, subpart UUUUb. The TAR authorizes tribes to develop and implement their own air quality programs, or portions thereof, under the CAA. However, it does not require tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. If a tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country.[16] A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities.

B. Where To Get a Copy of This Document and Other Related Information

In addition to being available in the docket, an electronic copy of these final rulemakings is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power*. Following signature by the EPA Administrator, the EPA will post a copy of these final rulemakings at this same website. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rules and key technical documents at this same website.

C. Judicial Review and Administrative Review

Under CAA section 307(b)(1), judicial review of these final actions is available only by filing a petition for review in

[16] See the EPA's website, *https://www.epa.gov/tribal/tribes-approved-treatment-state-tas*, for information on those tribes that have treatment as a state for specific environmental regulatory programs, administrative functions, and grant programs.

the United States Court of Appeals for the District of Columbia Circuit by July 8, 2024. These final actions are "standard[s] of performance or requirement[s] under section 111," and, in addition, are "nationally applicable regulations promulgated, or final action taken, by the Administrator under [the CAA]," CAA section 307(b)(1). Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment, (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC West Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

III. Climate Change Impacts

Elevated concentrations of GHGs have been warming the planet, leading to changes in the Earth's climate that are occurring at a pace and in a way that threatens human health, society, and the natural environment. While the EPA is not making any new scientific or factual findings with regard to the well-documented impact of GHG emissions on public health and welfare in support of these rules, the EPA is providing in this section a brief scientific background on climate change to offer additional context for these rulemakings and to help the public understand the environmental impacts of GHGs.

Extensive information on climate change is available in the scientific assessments and the EPA documents that are briefly described in this section, as well as in the technical and scientific information supporting them. One of those documents is the EPA's 2009 "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the CAA" (74 FR 66496, December 15, 2009) ("2009 Endangerment Finding"). In the 2009 Endangerment Finding, the Administrator found under section 202(a) of the CAA that elevated atmospheric concentrations of six key well-mixed GHGs—CO_2, methane (CH_4), nitrous oxide (N_2O), HFCs, perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—"may reasonably be anticipated to endanger the public health and welfare of current and future generations" (74 FR 66523, December 15, 2009). The 2009 Endangerment Finding, together with the extensive scientific and technical evidence in the supporting record, documented that climate change caused by human emissions of GHGs threatens the public health of the U.S. population. It explained that by raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses (74 FR 66497, December 15, 2009). While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. (74 FR 66525, December 15, 2009). The 2009 Endangerment Finding further explained that compared with a future without climate change, climate change is expected to increase tropospheric ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst tropospheric ozone problems, and thereby increase the risk of adverse effects on public health (74 FR 66525, December 15, 2009). Climate change is also expected to cause more intense hurricanes and more frequent and intense storms of other types and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders (74 FR 66525 December 15, 2009). Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects (74 FR 66498, December 15, 2009).

The 2009 Endangerment Finding also documented, together with the extensive scientific and technical evidence in the supporting record, that climate change touches nearly every aspect of public welfare [17] in the U.S., including the following: changes in water supply and quality due to changes in drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization). These impacts are also global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S. (74 FR 66530, December 15, 2009).

In 2016, the Administrator issued a similar finding for GHG emissions from aircraft under section 231(a)(2)(A) of the CAA.[18] In the 2016 Endangerment Finding, the Administrator found that the body of scientific evidence amassed in the record for the 2009 Endangerment Finding compellingly supported a similar endangerment finding under CAA section 231(a)(2)(A) and also found that the science assessments released between the 2009 and 2016 Findings "strengthen and further support the judgment that GHGs in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future generations" (81 FR 54424, August 15, 2016).

Since the 2016 Endangerment Finding, the climate has continued to change, with new observational records being set for several climate indicators such as global average surface temperatures, GHG concentrations, and sea level rise. Additionally, major scientific assessments continue to be released that further advance our understanding of the climate system and the impacts that GHGs have on public health and welfare for both current and future generations. These updated observations and projections document the rapid rate of current and future

[17] The CAA states in section 302(h) that "[a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants." 42 U.S.C. 7602(h).

[18] *Finding That Greenhouse Gas Emissions From Aircraft Cause or Contribute to Air Pollution That May Reasonably Be Anticipated To Endanger Public Health and Welfare.* 81 FR 54422, August 15, 2016 ("2016 Endangerment Finding").

climate change both globally and in the U.S.[19] [20] [21] [22] [23] [24] [25] [26] [27] [28] [29] [30] [31]

The most recent information demonstrates that the climate is continuing to change in response to the human-induced buildup of GHGs in the atmosphere. These recent assessments show that atmospheric concentrations of GHGs have risen to a level that has no precedent in human history and that they continue to climb, primarily because of both historical and current anthropogenic emissions, and that these elevated concentrations endanger our health by affecting our food and water sources, the air we breathe, the weather we experience, and our interactions with the natural and built environments. For example, atmospheric concentrations of one of these GHGs, CO_2, measured at Mauna Loa in Hawaii and at other sites around the world reached 419 parts per million (ppm) in 2022 (nearly 50 percent higher than preindustrial levels) [32] and have continued to rise at a rapid rate. Global average temperature has increased by about 1.1 °C (2.0 °F) in the 2011–2020 decade relative to 1850–1900.[33] The years 2015–2021 were the warmest 7 years in the 1880–2021 record, contributing to the warmest decade on record with a decadal temperature of 0.82 °C (1.48 °F) above the 20th century.[34] [35] The Intergovernmental Panel on Climate Change (IPCC) determined (with medium confidence) that this past decade was warmer than any multi-century period in at least the past 100,000 years.[36] Global average sea level has risen by about 8 inches (about 21 centimeters (cm)) from 1901 to 2018, with the rate from 2006 to 2018 (0.15 inches/year or 3.7 millimeters (mm)/year) almost twice the rate over the 1971 to 2006 period, and three times the rate of the 1901 to 2018 period.[37] The rate of sea level rise over the 20th century was higher than in any other century in at least the last 2,800 years.[38] Higher CO_2 concentrations have led to acidification of the surface ocean in recent decades to an extent unusual in the past 65 million years, with negative impacts on marine organisms that use calcium carbonate to build shells or skeletons.[39] Arctic sea ice extent continues to decline in all months of the year; the most rapid reductions occur in September (very likely almost a 13 percent decrease per decade between 1979 and 2018) and are unprecedented in at least 1,000 years.[40] Human-induced climate change has led to heatwaves and heavy precipitation becoming more frequent and more intense, along with increases in agricultural and ecological droughts [41] in many regions.[42]

The assessment literature demonstrates that modest additional amounts of warming may lead to a climate different from anything humans have ever experienced. The 2022 CO_2 concentration of 419 ppm is already higher than at any time in the last 2 million years.[43] If concentrations exceed 450 ppm, they would likely be higher than any time in the past 23 million years: [44] at the current rate of increase of more than 2 ppm per year, this would occur in about 15 years. While GHGs are not the only factor that controls climate, it is illustrative that 3 million years ago (the last time CO_2 concentrations were above 400 ppm) Greenland was not yet completely covered by ice and still supported forests, while 23 million years ago (the last time concentrations were above 450 ppm) the West Antarctic ice sheet was not yet developed, indicating the possibility that high GHG concentrations could lead to a world that looks very different from today and from the conditions in which human civilization has developed. If the Greenland and Antarctic ice sheets were

[19] USGCRP, 2017: *Climate Science Special Report: Fourth National Climate Assessment,* Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp, doi: 10.7930/J0J964J6.

[20] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C.

[21] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi:10.7930/NCA4.2018.

[22] IPCC, 2018: *Global Warming of 1.5 °C.* An IPCC Special Report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)].

[23] IPCC, 2019: *Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems* [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Pörtner, D.C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)].

[24] IPCC, 2019: *IPCC Special Report on the Ocean and Cryosphere in a Changing Climate* [H.-O. Pörtner, D.C. Roberts, V. Masson-Delmotte, P. Zhai, M. Tignor, E. Poloczanska, K. Mintenbeck, A. Alegriía, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

[25] National Academies of Sciences, Engineering, and Medicine. 2016. *Attribution of Extreme Weather Events in the Context of Climate Change.* Washington, DC: The National Academies Press. *https://dio.org/10.17226/21852.*

[26] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/24651.*

[27] National Academies of Sciences, Engineering, and Medicine. 2019. *Climate Change and Ecosystems.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/25504.*

[28] Blunden, J. and T. Boyer, Eds., 2022: "State of the Climate in 2021." Bull. Amer. Meteor. Soc., 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1.*

[29] U.S. Environmental Protection Agency. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. EPA 430–R–21–003.

[30] Jay, A.K., A.R. Crimmins, C.W. Avery, T.A. Dahl, R.S. Dodder, B.D. Hamlington, A. Lustig, K. Marvel, P.A. Méndez-Lazaro, M.S. Osler, A. Terando, E.S. Weeks, and A. Zycherman, 2023: Ch. 1. Overview: Understanding risks, impacts, and responses. In: Fifth National Climate Assessment. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. *https://doi.org/10.7930/NCA5.2023.CH1.*

[31] IPCC, 2023: Summary for Policymakers. In: Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)].

[32] *https://gml.noaa.gov/webdata/ccgg/trends/co2/co2_annmean_mlo.txt.*

[33] IPCC, 2021: Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 3–32, doi:10.1017/9781009157896.001.

[34] NOAA National Centers for Environmental Information, State of the Climate 2021 retrieved on August 3, 2023, from *https://www.ncei.noaa.gov/bams-state-of-climate.*

[35] Blunden, J. and T. Boyer, Eds., 2022: "State of the Climate in 2021." Bull. Amer. Meteor. Soc., 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate*1.

[36] IPCC, 2021.

[37] IPCC, 2021.

[38] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi:10.7930/NCA4.2018.

[39] IPCC, 2018.

[40] IPCC, 2021.

[41] These are drought measures based on soil moisture.

[42] IPCC, 2021.

[43] Annual Mauna Loa CO_2 concentration data from *https://gml.noaa.gov/webdata/ccgg/trends/co2/co2_annmean_mlo.txt,* accessed September 9, 2023.

[44] IPCC, 2013.

to melt substantially, sea levels would rise dramatically.

The NCA4 found that it is very likely (greater than 90 percent likelihood) that by mid-century, the Arctic Ocean will be almost entirely free of sea ice by late summer for the first time in about 2 million years.[45] Coral reefs will be at risk for almost complete (99 percent) losses with 1 °C (1.8 °F) of additional warming from today (2 °C or 3.6 °F since preindustrial). At this temperature, between 8 and 18 percent of animal, plant, and insect species could lose over half of the geographic area with suitable climate for their survival, and 7 to 10 percent of rangeland livestock would be projected to be lost.[46] The IPCC similarly found that climate change has caused substantial damages and increasingly irreversible losses in terrestrial, freshwater, and coastal and open ocean marine ecosystems.

Every additional increment of temperature comes with consequences. For example, the half degree of warming from 1.5 to 2 °C (0.9 °F of warming from 2.7 °F to 3.6 °F) above preindustrial temperatures is projected on a global scale to expose 420 million more people to frequent extreme heatwaves at least every five years, and 62 million more people to frequent exceptional heatwaves at least every five years (where heatwaves are defined based on a heat wave magnitude index which takes into account duration and intensity—using this index, the 2003 French heat wave that led to almost 15,000 deaths would be classified as an "extreme heatwave" and the 2010 Russian heatwave which led to thousands of deaths and extensive wildfires would be classified as "exceptional"). It would increase the frequency of sea-ice-free Arctic summers from once in 100 years to once in a decade. It could lead to 4 inches of additional sea level rise by the end of the century, exposing an additional 10 million people to risks of inundation as well as increasing the probability of triggering instabilities in either the Greenland or Antarctic ice sheets. Between half a million and a million additional square miles of permafrost would thaw over several centuries. Risks to food security would increase from medium to high for several lower-income regions in the Sahel, southern Africa, the Mediterranean, central Europe, and the Amazon. In addition to food security issues, this temperature increase would have implications for human health in terms of increasing ozone concentrations, heatwaves, and vector-borne diseases (for example, expanding the range of the mosquitoes which carry dengue fever, chikungunya, yellow fever, and the Zika virus or the ticks which carry Lyme, babesiosis, or Rocky Mountain Spotted Fever).[47] Moreover, every additional increment in warming leads to larger changes in extremes, including the potential for events unprecedented in the observational record. Every additional degree will intensify extreme precipitation events by about 7 percent. The peak winds of the most intense tropical cyclones (hurricanes) are projected to increase with warming. In addition to a higher intensity, the IPCC found that precipitation and frequency of rapid intensification of these storms has already increased, the movement speed has decreased, and elevated sea levels have increased coastal flooding, all of which make these tropical cyclones more damaging.[48]

The NCA4 also evaluated a number of impacts specific to the U.S. Severe drought and outbreaks of insects like the mountain pine beetle have killed hundreds of millions of trees in the western U.S. Wildfires have burned more than 3.7 million acres in 14 of the 17 years between 2000 and 2016, and Federal wildfire suppression costs were about a billion dollars annually.[49] The National Interagency Fire Center has documented U.S. wildfires since 1983, and the 10 years with the largest acreage burned have all occurred since 2004.[50] Wildfire smoke degrades air quality, increasing health risks, and more frequent and severe wildfires due to climate change would further diminish air quality, increase incidences of respiratory illness, impair visibility, and disrupt outdoor activities, sometimes thousands of miles from the location of the fire. Meanwhile, sea level rise has amplified coastal flooding and erosion impacts, requiring the installation of costly pump stations, flooding streets, and increasing storm surge damages. Tens of billions of dollars of U.S. real estate could be below sea level by 2050 under some scenarios. Increased frequency and duration of drought will reduce agricultural productivity in some regions, accelerate depletion of water supplies for irrigation, and expand the distribution and incidence of pests and diseases for crops and livestock. The NCA4 also recognized that climate change can increase risks to national security, both through direct impacts on military infrastructure and by affecting factors such as food and water availability that can exacerbate conflict outside U.S. borders. Droughts, floods, storm surges, wildfires, and other extreme events stress nations and people through loss of life, displacement of populations, and impacts on livelihoods.[51] The NCA5 further reinforces the science showing that climate change will have many impacts on the U.S., as described above in the preamble. Particularly relevant for these rules, the NCA5 states that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends." [52]

EPA modeling efforts can further illustrate how these impacts from climate change may be experienced across the U.S. EPA's Framework for Evaluating Damages and Impacts (FrEDI) [53] uses information from over 30 peer-reviewed climate change impact studies to project the physical and economic impacts of climate change to the U.S. resulting from future temperature changes. These impacts are projected for specific regions within the U.S. and for more than 20 impact categories, which span a large number of sectors of the U.S. economy.[54] Using

[45] USGCRP, 2018.

[46] IPCC, 2018.

[47] IPCC, 2018.

[48] IPCC, 2021.

[49] USGCRP, 2018.

[50] NIFC (National Interagency Fire Center). 2021. Total wildland fires and acres (1983–2020). Accessed August 2021. *https://www.nifc.gov/fireInfo/fireInfo_stats_totalFires.html.*

[51] USGCRP, 2018.

[52] Jay, A.K., A.R. Crimmins, C.W. Avery, T.A. Dahl, R.S. Dodder, B.D. Hamlington, A. Lustig, K. Marvel, P.A. Méndez-Lazaro, M.S. Osler, A. Terando, E.S. Weeks, and A. Zycherman, 2023: Ch. 1. Overview: Understanding risks, impacts, and responses. In: *Fifth National Climate Assessment.* Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. *https://doi.org/10.7930/NCA5.2023.CH1.*

[53] (1) Hartin, C., *et al.* (2023). Advancing the estimation of future climate impacts within the United States. Earth Syst. Dynam., 14, 1015–1037, *https://doi.org/10.5194/esd-14-1015-2023.* (2) Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances," Docket ID No. EPA–HQ–OAR–2021–0317, November 2023, (3) *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050.* Published by the U.S. Department of State and the U.S. Executive Office of the President, Washington DC. November 2021, (4) *Climate Risk Exposure: An Assessment of the Federal Government's Financial Risks to Climate Change,* White Paper, Office of Management and Budget, April 2022.

[54] EPA (2021). Technical Documentation on the Framework for Evaluating Damages and Impacts (FrEDI). U.S. Environmental Protection Agency, EPA 430–R–21–004, *https://www.epa.gov/cira/fredi.* Documentation has been subject to both a public review comment period and an independent

Continued

this framework, the EPA estimates that global emission projections, with no additional mitigation, will result in significant climate-related damages to the U.S.[55] These damages to the U.S. would mainly be from increases in lives lost due to increases in temperatures, as well as impacts to human health from increases in climate-driven changes in air quality, dust and wildfire smoke exposure, and incidence of suicide. Additional major climate-related damages would occur to U.S. infrastructure such as roads and rail, as well as transportation impacts and coastal flooding from sea level rise, increases in property damage from tropical cyclones, and reductions in labor hours worked in outdoor settings and buildings without air conditioning. These impacts are also projected to vary from region to region with the Southeast, for example, projected to see some of the largest damages from sea level rise, the West Coast projected to experience damages from wildfire smoke more than other parts of the country, and the Northern Plains states projected to see a higher proportion of damages to rail and road infrastructure. While information on the distribution of climate impacts helps to better understand the ways in which climate change may impact the U.S., recent analyses are still only a partial assessment of climate impacts relevant to U.S. interests and in addition do not reflect increased damages that occur due to interactions between different sectors impacted by climate change or all the ways in which physical impacts of climate change occurring abroad have spillover effects in different regions of the U.S.

Some GHGs also have impacts beyond those mediated through climate change. For example, elevated concentrations of CO_2 stimulate plant growth (which can be positive in the case of beneficial species, but negative in terms of weeds and invasive species, and can also lead to a reduction in plant micronutrients[56]) and cause ocean acidification. Nitrous oxide depletes the levels of protective stratospheric ozone.[57] Methane reacts to form tropospheric ozone.

Section XII.E of this preamble discusses the impacts of GHG emissions on individuals living in socially and economically vulnerable communities. While the EPA did not conduct modeling to specifically quantify changes in climate impacts resulting from these rules in terms of avoided temperature change or sea-level rise, the Agency did quantify climate benefits by monetizing the emission reductions through the application of the social cost of greenhouse gases (SC–GHGs), as described in section XII.D of this preamble.

These scientific assessments, the EPA analyses, and documented observed changes in the climate of the planet and of the U.S. present clear support regarding the current and future dangers of climate change and the importance of GHG emissions mitigation.

IV. Recent Developments in Emissions Controls and the Electric Power Sector

In this section, we discuss background information about the electric power sector and controls available to limit GHG pollution from the fossil fuel-fired power plants regulated by these final rules, and then discuss several recent developments that are relevant for determining the BSER for these sources. After giving some general background, we first discuss CCS and explain that its costs have fallen significantly. Lower costs are central for the EPA's determination that CCS is the BSER for certain existing coal-fired steam generating units and certain new natural gas-fired combustion turbines. Second, we discuss natural gas co-firing for coal-fired steam generating units and explain recent reductions in cost for this approach as well as its widespread availability and current and potential deployment within this subcategory. Third, we discuss highly efficient generation as a BSER technology for new and reconstructed simple cycle and combined cycle combustion turbine EGUs. The emission reductions achieved by highly efficient turbines are well demonstrated in the power sector, and along with operational and maintenance best practices, represent a cost-effective technology that reduces fuel consumption. Finally, we discuss key developments in the electric power sector that influence which units can feasibly and cost-effectively deploy these technologies.

A. Background

1. Electric Power Sector

Electricity in the U.S. is generated by a range of technologies, and different EGUs play different roles in providing reliable and affordable electricity. For example, certain EGUs generate base load power, which is the portion of electricity loads that are continually present and typically operate throughout all hours of the year. Intermediate EGUs often provide complementary generation to balance variable supply and demand resources. Low load ''peaking units'' provide capacity during hours of the highest daily, weekly, or seasonal net demand, and while these resources have low levels of utilization on an annual basis, they play important roles in providing generation to meet short-term demand and often must be available to quickly increase or decrease their output. Furthermore, many of these EGUs also play important roles ensuring the reliability of the electric grid, including facilitating the regulation of frequency and voltage, providing ''black start'' capability in the event the grid must be repowered after a widespread outage, and providing reserve generating capacity[58] in the event of unexpected changes in the availability of other generators.

In general, the EGUs with the lowest operating costs are dispatched first, and, as a result, an inefficient EGU with high fuel costs will typically only operate if other lower-cost plants are unavailable or are insufficient to meet demand. Units are also unavailable during both routine and unanticipated outages, which typically become more frequent as power plants age. These factors result in the mix of available generating capacity types (*e.g.*, the share of capacity of each type of generating source) being substantially different than the mix of the share of total electricity produced by each type of generating source in a given season or year.

expert peer review, following EPA peer-review guidelines.

[55] Compared to a world with no additional warming after the model baseline (1986–2005).

[56] Ziska, L., A. Crimmins, A. Auclair, S. DeGrasse, J.F. Garofalo, A.S. Khan, I. Loladze, A.A. Pérez de León, A. Showler, J. Thurston, and I. Walls, 2016: Ch. 7: *Food Safety, Nutrition, and Distribution. The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* U.S. Global Change Research Program, Washington, DC, 189–216. *https://health2016.globalchange.gov/low/ClimateHealth2016_07_Food_small.pdf.*

[57] WMO (World Meteorological Organization), *Scientific Assessment of Ozone Depletion: 2018, Global Ozone Research and Monitoring Project*—Report No. 58, 588 pp., Geneva, Switzerland, 2018.

[58] Generation and capacity are commonly reported statistics with key distinctions. Generation is the production of electricity and is a measure of an EGU's *actual* output while capacity is a measure of the maximum *potential* production of an EGU under certain conditions. There are several methods to calculate an EGU's capacity, which are suited for different applications of the statistic. Capacity is typically measured in megawatts (MW) for individual units or gigawatts (1 GW = 1,000 MW) for multiple EGUs. Generation is often measured in kilowatt-hours (1 kWh = 1,000 watt-hours), megawatt-hours (1 MWh = 1,000 kWh), gigawatt-hours (1 GWh = 1 million kWh), or terawatt-hours (1 TWh = 1 billion kWh).

Generated electricity must be transmitted over networks [59] of high voltage lines to substations where power is stepped down to a lower voltage for local distribution. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator; [60] in others, individual utilities [61] coordinate the operations of their generation and transmission to balance the system across their respective service territories.

2. Types of EGUs

There are many types of EGUs including fossil fuel-fired power plants (*i.e.*, those using coal, oil, and natural gas), nuclear power plants, renewable generating sources (such as wind and solar) and others. This rule focuses on the fossil fuel-fired portion of the generating fleet that is responsible for the vast majority of GHG emissions from the power sector. The definition of fossil fuel-fired electric utility steam generating units includes utility boilers as well as those that use gasification technology (*i.e.*, integrated gasification combined cycle (IGCC) units). While coal is the most common fuel for fossil fuel-fired utility boilers, natural gas can also be used as a fuel in these EGUs and many existing coal- and oil-fired utility boilers have refueled as natural gas-fired utility boilers. An IGCC unit gasifies fuel—typically coal or petroleum coke—to form a synthetic gas (or syngas) composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power. The heat created by these technologies produces high-pressure steam that is released to rotate turbines, which, in turn, spin an electric generator.

Stationary combustion turbine EGUs (most commonly natural gas-fired) use one of two configurations: combined cycle or simple cycle turbines. Combined cycle units have two generating components (*i.e.*, two cycles) operating from a single source of heat. Combined cycle units first generate power from a combustion turbine (*i.e.*, the combustion cycle) directly from the heat of burning natural gas or other fuel. The second cycle reuses the waste heat from the combustion turbine engine, which is routed to a heat recovery steam generator (HRSG) that generates steam, which is then used to produce additional power using a steam turbine (*i.e.*, the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Combined cycle units that fire mostly natural gas are commonly referred to as natural gas combined cycle (NGCC) units, and, with greater efficiency, are utilized at higher capacity factors to provide base load or intermediate load power. An EGU's capacity factor indicates a power plant's electricity output as a percentage of its total generation capacity. Simple cycle turbines only use a combustion turbine to produce electricity (*i.e.*, there is no heat recovery or steam cycle). These less-efficient combustion turbines are generally utilized at non-base load capacity factors and contribute to reliable operations of the grid during periods of peak demand or provide flexibility to support increased generation from variable energy sources.[62]

Other generating sources produce electricity by harnessing kinetic energy from flowing water, wind, or tides, thermal energy from geothermal wells, or solar energy primarily through photovoltaic solar arrays. Spurred by a combination of declining costs, consumer preferences, and government policies, the capacity of these renewable technologies is growing, and when considered with existing nuclear energy, accounted for 40 percent of the overall net electricity supply in 2022. Many projections show this share growing over time. For example, the EPA's Power Sector Platform 2023 using IPM (*i.e.*, the EPA's baseline projections of the power sector) projects zero-emitting sources reaching 76 percent of electricity generation by 2040. This shift is driven by multiple factors. These factors include changes in the relative economics of generating technologies, the efforts by states to reduce GHG emissions, utility and other corporate commitments, and customer preference. The shift is further promoted by provisions of Federal legislation, most notably the Clean Electricity Investment and Production tax credits included in IRC sections 48E and 45Y of the IRA, which do not begin to phase out until the later of 2032 or when power sector GHG emissions are 75 percent less than 2022 levels. (See section IV.F of this preamble and the accompanying RIA for additional discussion of projections for the power sector.) These projections are consistent with power company announcements. For example, as the Edison Electric Institute (EEI) stated in pre-proposal public comments submitted to the regulatory docket: "Fifty EEI members have announced forward-looking carbon reduction goals, two-thirds of which include a net-zero by 2050 or earlier equivalent goal, and members are routinely increasing the ambition or speed of their goals or altogether transforming them into net-zero goals . . . . EEI's member companies see a clear path to continued emissions reductions over the next decade using current technologies, including nuclear power, natural gas-based generation, energy demand efficiency, energy storage, and deployment of new renewable energy—especially wind and solar—as older coal-based and less-efficient natural gas-based generating units retire." [63] The Energy Strategy Coalition similarly said in public comments that "[a]s major electrical utilities and power producers, our top priority is providing clean, affordable, and reliable energy to our customers" and are "seeking to advance" technologies "such as a carbon capture and storage, which can significantly reduce carbon dioxide

[59] The three network interconnections are the Western Interconnection, comprising the western parts of the U.S. and Canada, the Eastern Interconnection, comprising the eastern parts of the U.S. and Canada except parts of Eastern Canada in the Quebec Interconnection, and the Texas Interconnection, encompassing the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT). See map of all NERC interconnections at *https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf.*

[60] For example, PJM Interconnection, LLC, New York Independent System Operator (NYISO), Midwest Independent System Operator (MISO), California Independent System Operator (CAISO), *etc.*

[61] For example, Los Angeles Department of Power and Water, Florida Power and Light, *etc.*

[62] Non-dispatchable renewable energy (electrical output cannot be used at any given time to meet fluctuating demand) is both variable and intermittent and is often referred to as intermittent renewable energy. The variability aspect results from predictable changes in electric generation (*e.g.*, solar not generating electricity at night) that often occur on longer time periods. The intermittent aspect of renewable energy results from inconsistent generation due to unpredictable external factors outside the control of the owner/operator (*e.g.*, imperfect local weather forecasts) that often occur on shorter time periods. Since renewable energy fluctuates over multiple time periods, grid operators are required to adjust forecast and real time operating procedures. As more renewable energy is added to the electric grid and generation forecasts improve, the intermittency of renewable energy is reduced.

[63] Edison Electric Institute (EEI). (November 18, 2022). *Clean Air Act Section 111 Standards and the Power Sector: Considerations and Options for Setting Standards and Providing Compliance Flexibility to Units and States.* Public comments submitted to the EPA's pre-proposal rulemaking, Document ID No. EPA–HQ–OAR–2022–0723–0024.

emissions from fossil fuel-fired EGUs.''[64]

B. GHG Emissions From Fossil Fuel-Fired EGUs

The principal GHGs that accumulate in the Earth's atmosphere above pre-industrial levels because of human activity are CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. Of these, CO_2 is the most abundant, accounting for 80 percent of all GHGs present in the atmosphere. This abundance of CO_2 is largely due to the combustion of fossil fuels by the transportation, electricity, and industrial sectors.[65]

The amount of CO_2 produced when a fossil fuel is burned in an EGU is a function of the carbon content of the fuel relative to the size and efficiency of the EGU. Different fuels emit different amounts of CO_2 in relation to the energy they produce when combusted. The heat content, or the amount of energy produced when a fuel is burned, is mainly determined by the carbon and hydrogen content of the fuel. For example, in terms of pounds of CO_2 emitted per million British thermal units of energy produced when combusted, natural gas is the lowest compared to other fossil fuels at 117 lb CO_2/MMBtu.[66] [67] The average for coal is 216 lb CO_2/MMBtu, but varies between 206 to 229 lb CO_2/MMBtu by type (*e.g.*, anthracite, lignite, subbituminous, and bituminous).[68] The value for petroleum products such as diesel fuel and heating oil is 161 lb CO_2/MMBtu.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks[69] (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It presents total U.S. anthropogenic emissions and sinks[70] of GHGs, including CO_2 emissions since 1990. According to the latest inventory of all sectors, in 2021, total U.S. GHG emissions were 6,340 million metric tons of CO_2 equivalent (MMT CO_2e).[71] The transportation sector (28.5 percent), which includes approximately 300 million vehicles, was the largest contributor to total U.S. GHG emissions with 1,804 MMT CO_2e followed by the power sector (25.0 percent) with 1,584 MMT CO_2e. In fact, GHG emissions from the power sector were higher than the GHG emissions from all other industrial sectors combined (1,487 MMT CO_2e). Specifically, the power sector's emissions were far more than petroleum and natural gas systems[72] at 301 MMT CO_2e; chemicals (71 MMT CO_2e); minerals (64 MMT CO_2e); coal mining (53 MMT CO_2e); and metals (48 MMT CO_2e). The agriculture (636 MMT CO_2e), commercial (439 MMT CO_2e), and residential (366 MMT CO_2e) sectors combined to emit 1,441 MMT CO_2e.

Fossil fuel-fired EGUs are by far the largest stationary source emitters of GHGs in the nation. For example, according to the EPA's Greenhouse Gas Reporting Program (GHGRP), of the top 100 large facilities that reported facility-level GHGs in 2022, 85 were fossil fuel-fired power plants while 10 were refineries and/or chemical plants, four were metals facilities, and one was a petroleum and natural gas systems facility.[73] Of the 85 fossil fuel-fired power plants, 81 were primarily coal-fired, including the top 41 emitters of CO_2. In addition, of the 81 coal-fired plants, 43 have no retirement planned prior to 2039. The top 10 of these plants combined to emit more than 135 MMT of CO_2e, with the top emitter (James H. Miller power plant in Alabama) reporting approximately 22 MMT of CO_2e with each of its four EGUs emitting between 5 MMT and 6 MMT CO_2e that year. The combined capacity of these 10 plants is more than 23 gigawatts (GW), and all except for the Monroe (Michigan) plant operated at annual capacity factors of 50 percent or higher.[74] For comparison, the largest GHG emitter in the U.S. that is not a fossil fuel-fired power plant is the ExxonMobil refinery and chemical plant in Baytown, Texas, which reported 12.6 MMT CO_2e (No. 6 overall in the nation) to the GHGRP in 2022. The largest metals facility in terms of GHG emissions was the U.S. Steel facility in Gary, Indiana, with 10.4 MMT CO_2e (No. 16 overall in the nation).

Overall, CO_2 emissions from the power sector have declined by 36 percent since 2005 (when the power sector reached annual emissions of 2,400 MMT CO_2, its historical peak to date).[75] The reduction in CO_2 emissions can be attributed to the power sector's ongoing trend away from carbon-intensive coal-fired generation and toward more natural gas-fired and renewable sources. In 2005, CO_2 emissions from coal-fired EGUs alone measured 1,983 MMT.[76] This total dropped to 1,351 MMT in 2015 and reached 974 MMT in 2019, the first time since 1978 that CO_2 emissions from coal-fired EGUs were below 1,000 MMT. In 2020, emissions of CO_2 from coal-fired EGUs measured 788 MMT as the result of pandemic-related closures and reduced utilization before rebounding in 2021 to 909 MMT. By contrast, CO_2 emissions from natural gas-fired generation have almost doubled since 2005, increasing from 319 MMT to 613 MMT in 2021, and CO_2 emissions from petroleum products (*i.e.*, distillate fuel oil, petroleum coke, and residual fuel oil) declined from 98 MMT in 2005 to 18 MMT in 2021.

[64] Energy Strategy Coalition Comments on EPA'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, Document ID No. EPA–HQ–OAR–2023–0072–0672, August 14, 2023.

[65] U.S. Environmental Protection Agency (EPA). Overview of greenhouse gas emissions. July 2021. *https://www.epa.gov/ghgemissions/overview-greenhouse-gases#carbon-dioxide.*

[66] Natural gas is primarily CH_4, which has a higher hydrogen to carbon atomic ratio, relative to other fuels, and thus, produces the least CO_2 per unit of heat released. In addition to a lower CO_2 emission rate on a lb/MMBtu basis, natural gas is generally converted to electricity more efficiently than coal. According to EIA, the 2020 emissions rate for coal and natural gas were 2.23 lb CO_2/kWh and 0.91 lb CO_2/kWh, respectively. *www.eia.gov/tools/faqs/faq.php?id=74&t=11.*

[67] Values reflect the carbon content on a per unit of energy produced on a higher heating value (HHV) combustion basis and are not reflective of recovered useful energy from any particular technology.

[68] Energy Information Administration (EIA). *Carbon Dioxide Emissions Coefficients. https://www.eia.gov/environment/emissions/co2_vol_mass.php.*

[69] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021.*

[70] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep-sea reservoirs of carbon dioxide.

[71] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.*

[72] Petroleum and natural gas systems include: offshore and onshore petroleum and natural gas production; onshore petroleum and natural gas gathering and boosting; natural gas processing; natural gas transmission/compression; onshore natural gas transmission pipelines; natural gas local distribution companies; underground natural gas storage; liquified natural gas storage; liquified natural gas import/export equipment; and other petroleum and natural gas systems.

[73] U.S. Environmental Protection Agency (EPA). Greenhouse Gas Reporting Program. Facility Level Information on Greenhouse Gases Tool (FLIGHT). *https://ghgdata.epa.gov/ghgp/main.do#.*

[74] U.S. Energy Information Administration (EIA). Preliminary Monthly Electric Generator Inventory, Form EIA–860M, November 2023. *https://www.eia.gov/electricity/data/eia860m/.*

[75] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020. https://cfpub.epa.gov/ghgdata/inventoryexplorer/#electricitygeneration/entiresector/allgas/category/all.*

[76] U.S. Energy Information Administration (EIA). Monthly Energy Review, table 11.6. September 2022. *https://www.eia.gov/totalenergy/data/monthly/pdf/sec11.pdf.*

When the EPA finalized the Clean Power Plan (CPP) in October 2015, the Agency projected that, as a result of the CPP, the power sector would reduce its annual CO_2 emissions to 1,632 MMT by 2030, or 32 percent below 2005 levels (2,400 MMT).[77] Instead, even in the absence of Federal regulations for existing EGUs, annual CO_2 emissions from sources covered by the CPP had fallen to 1,540 MMT by the end of 2021, a nearly 36 percent reduction below 2005 levels. The power sector achieved a deeper level of reductions than forecast under the CPP and approximately a decade ahead of time. By the end of 2015, several months after the CPP was finalized, those sources already had achieved CO_2 emission levels of 1,900 MMT, or approximately 21 percent below 2005 levels. However, progress in emission reductions is not uniform across all states and is not guaranteed to continue, therefore Federal policies play an essential role. As discussed earlier in this section, the power sector remains a leading emitter of CO_2 in the U.S., and, despite the emission reductions since 2005, current CO_2 levels continue to endanger human health and welfare. Further, as sources in other sectors of the economy turn to electrification to decarbonize, future CO_2 reductions from fossil fuel-fired EGUs have the potential to take on added significance and increased benefits.

C. Recent Developments in Emissions Control

This section of the preamble describes recent developments in GHG emissions control in general. Details of those controls in the context of BSER determination are provided in section VII.C.1.a for CCS on coal-fired steam generating units, section VII.C.2.a for natural gas co-firing on coal-fired steam generating units, section VIII.F.2.b for efficient generation on natural gas-fired combustion turbines, and section VIII.F.4.c.iv for CCS on natural gas-fired combustion turbines. Further details of the control technologies are available in the final TSDs, *GHG Mitigation Measures for Steam Generating Units* and *GHG Mitigation Measures—CCS for Combustion Turbines*, available in the docket for these actions.

1. CCS

One of the key GHG reduction technologies upon which the BSER determinations are founded in these final rules is CCS—a technology that can capture and permanently store CO_2 from fossil fuel-fired EGUs. CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s [78] and has been used in a variety of industrial applications for decades. Thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[79] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with enhanced oil recovery (EOR).[80] The American Petroleum Institute (API) explains that "CCS is a proven technology" and that "[t]he methods that apply to [the] carbon sequestration process are not novel. The U.S. has more than 40 years of CO_2 gas injection and storage experience. During the last 40 years the U.S. gas and oil industry's (EOR) enhanced oil recovery operations) have injected more than 1 billion tonnes of CO_2." [81] [82]

In 2009, Mike Morris, then-CEO of American Electric Power (AEP), was interviewed by Reuters and the article noted that Morris's "companies' work in West Virginia on [CCS] gave [Morris] more insight than skeptics who doubt the technology." In that interview, Morris explained, "I'm convinced it will be primetime ready by 2015 and deployable." [83] In 2011, Alstom Power, the company that developed the 30 MW pilot project upon which Morris had based his conclusions, reiterated the claim that CCS would be commercially available in 2015. A press release from Alstom Power stated that, based on the results of Alstom's "13 pilot and demonstration projects and validated by independent experts . . . we can now be confident that CCS works and is cost effective . . . and will be available at a commercial scale in 2015 and will allow [plants] to capture 90% of the emitted CO_2." The press release went on to note that "the same conclusion applies for a gas plant using CCS." [84]

In 2011, however, AEP determined that the economic and regulatory environment at the time did not support further development of the technology. After canceling a large-scale commercial project, Morris explained, "as a regulated utility, it is impossible to gain regulatory approval to cover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place." [85]

Thirteen years later, the situation is fundamentally different. Since 2011, the technological advances from full-scale deployments (*e.g.*, the Petra Nova and Boundary Dam projects discussed later in this preamble) combined with supportive policies in multiple states and the financial incentives included in the IRA, mean that CCS can be deployed at scale today. In addition to applications at fossil fuel-fired EGUs, installation of CCS is poised to dramatically increase across a range of industries in the coming years, including ethanol production, natural gas processing, and steam methane reformers.[86] Many of the CCS projects across these industries, including capture systems, pipelines, and sequestration, are already in operation or are in advanced stages of deployment. There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under

[77] 80 FR 63662 (October 23, 2015).

[78] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[79] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, "Hazardous Annual Liquid Data." 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[80] GHGRP US EPA. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[81] American Petroleum Institute (API). (2024). Carbon Capture and Storage: A Low-Carbon Solution to Economy-Wide Greenhouse Gas Emissions Reductions. *https://www.api.org/news-policy-and-issues/carbon-capture-storage.*

[82] Major energy company presidents have made similar statements. For example, in 2021, Shell Oil Company president Gretchen H. Watkins testified to Congress that "Carbon capture and storage is a proven technology," and in 2022, Joe Blommaert, the president of ExxonMobil Low Carbon Solutions, stated that "Carbon capture and storage is a readily available technology that can play a critical role in helping society reduce greenhouse gas emissions." See *https://www.congress.gov/117/meeting/house/114185/witnesses/HHRG-117-GO00-Wstate-WatkinsG-20211028.pdf* and *https://corporate.exxonmobil.com/news/news-releases/2022/0225_exxonmobil-to-expand-carbon-capture-and-storage-at-labarge-wyoming-facility.*

[83] Woodall, B. (June 25, 2009). AEP sees carbon capture from coal ready by 2015. Reuters. *https://www.reuters.com/article/idUSTRE55O6TS/.*

[84] Alstom Power. (June 14, 2011). Alstom Power study demonstrates carbon capture and storage (CCS) is efficient and cost competitive. *https://www.alstom.com/press-releases-news/2011/6/press-releases-3-26.*

[85] Indiana Michigan Power. (July 14, 2011). AEP Places Carbon Capture Commercialization on Hold, Citing Uncertain Status of Climate Policy, Weak Economy. Press release. *https://www.indianamichiganpower.com/company/news/view?releaseID=1206.*

[86] U.S. Department of Energy (DOE). (2023). Pathways to Commercial Liftoff: Carbon Management. *https://liftoff.energy.gov/wp-content/uploads/2024/02/20230424-Liftoff-Carbon-Management-vPUB_update4.pdf.*

construction or in advanced stages of development.[87]

Process improvements learned from earlier deployments of CCS, the availability of better solvents, and other advances have decreased the costs of CCS in recent years. As a result, the cost of CO_2 capture, excluding any tax credits, from coal-fired power generation is projected to fall by 50 percent by 2025 compared to 2010.[88] The IRA makes additional and significant reductions in the cost of implementing CCS by extending and increasing the tax credit for CO_2 sequestration under IRC section 45Q.

With this combination of polices, and the advances related to CO_2 capture, multiple projects consistent with the emission reduction requirements of a 90 percent capture amine based BSER are in advanced stages of development. These projects use a wider range of technologies, and some of them are being developed as first-of-a-kind projects and offer significant advantages over the amine-based CCS technology that the EPA is finalizing as BSER.

For instance, in North Dakota, Governor Doug Burgum announced a goal of becoming carbon neutral by 2030 while retaining the core position of its fossil fuel industries, and to do so by significant CCS implementation. Gov. Burgum explained, ''This may seem like a moonshot goal, but it's actually not. It's actually completely doable, even with the technologies that we have today.'' [89] Companies in the state are backing up this claim with projects in multiple industries in various stages of operation and development. In the power sector, two of the biggest projects under development are Project Tundra and Coal Creek. Project Tundra is a carbon capture project on Minnkota Power's 705 MW Milton R Young Power Plant in Oliver County, North Dakota. Mitsubishi Heavy Industries will be providing an advanced version of its carbon capture equipment that builds upon the lessons learned from the Petra Nova project.[90] Rainbow Energy is developing the project at the Coal Creek Station, located in McLean, North Dakota. Notably, Rainbow Energy purchased the 1,150 MW Coal Creek Station with a business model of installing CCS based on the IRC section 45Q tax credit of $50/ton that existed at the time (the IRA has since increased the amount to $85/ton).[91] Rainbow Energy explains, ''CCUS technology has been proven and is an economical option for a facility like Coal Creek Station. We see CCUS as the best way to manage emissions at our facility.'' [92]

While North Dakota has encouraged CCS on coal-fired power plants without specific mandates, Wyoming is taking a different approach. Senate Bill 42, enacted in 2024, requires utilities to generate a specified percentage of their electricity using coal-fired power plants with CCS. SB 42 updates HB 200, enacted in 2020, which required the CCS to be installed by 2030, which SB 42 extends to 2033. To comply with those requirements, PacificCorp has stated in its 2023 IRP that it intends to install CCS on two coal-fired units by 2028.[93] Rocky Mountain Power has also announced that it will explore a new carbon capture technology at either its David Johnston plant or its Wyodak plant.[94] Another CCS project is also under development at the Dry Fork Power Plant in Wyoming. Currently, a pilot project that will capture 150 tons of CO_2 per day is under construction and is scheduled to be completed in late 2024. Work has also begun on a full-scale front end engineering design (FEED) study.

Like North Dakota, West Virginia does not have a carbon capture mandate, but there are several carbon capture projects under development in the state. One is a new, 2,000 MW natural gas combined cycle plant being developed by Competitive Power Ventures that will capture 90–95 percent of the CO_2 using GE turbine and carbon capture technology.[95] A second is an Omnis Fuel Technologies project to convert the coal-fired Pleasants Power Station to run on hydrogen.[96] Omnis intends to use a pyrolysis-based process to convert coal into hydrogen and graphite. Because the graphite is a usable, solid form of carbon, no CO_2 sequestration will be required. Therefore, unlike more traditional amine-based approaches, instead of the captured CO_2 being a cost, the graphite product will provide a revenue stream.[97] Omnis states that the Pleasants Power Project broke ground in August 2023 and will be online by 2025.

It should be noted that Wyoming, West Virginia, and North Dakota represented the first-, second-, and seventh-largest coal producers, respectively, in the U.S. in 2022.[98]

In addition to the coal-based CCS projects mentioned above, multiple other projects are in advanced stages of development and/or have completed FEED studies. For instance, Linde/BASF is installing a 10 MW pilot project on the Dallman Power Plant in Illinois. Based on results from small scale pilot studies, techno economic analysis indicates that the Linde/BASF process can provide a significant reduction in capital costs compared to the NETL base case for a supercritical pulverized coal plant with carbon capture.'' [99] Multiple other FEED studies are either completed or under development, putting those projects on a path to being able to be built and to commence operation well before January 1, 2032.

In addition to the Competitive Power Partners project, there are multiple post-combustion CCS retrofit projects in various stages of development. In particular, NET Power is in advanced stages of development on a 300 MW project in west Texas using the Allam-Fetvedt cycle, which is being designed to achieve greater than 97 percent CO_2 capture. In addition to working on this first project, NET Power has indicated that it has an additional project under development and is working with

[87] Congressional Budget Office (CBO). (December 13, 2023). Carbon Capture and Storage in the United States. *https://www.cbo.gov/publication/59345.*

[88] Global CCS Institute. (March 2021). Technology Readiness and Costs of CCS. *https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf.*

[89] Willis, A. (May 12, 2021). Gov. Doug Burgum calls for North Dakota to be carbon neutral by 2030. The Dickinson Press. *https://www.thedickinsonpress.com/business/gov-doug-burgum-calls-for-north-dakota-to-be-carbon-neutral-by-2030.*

[90] Tanaka, H. et al. Advanced KM CDR Process using New Solvent. 14th International Conference on Greenhouse Gas Control Technologies, GHGT–14. *https://www.cfaenm.org/wp-content/uploads/2019/03/GHGT14_manuscript_20180913Clean-version.pdf.*

[91] Minot Daily News. (April 8, 2024). Hoeven: ND to lead country with carbon capture project at Coal Creek Station. *https://minotdailynews.com/news/local-news/2021/07/hoeven-nd-to-lead-country-with-carbon-capture-project-at-coal-creek-station/.*

[92] Rainbow Energy Center. (ND). Carbon Capture. *https://rainbowenergycenter.com/what-we-do/carbon-capture/.*

[93] PacifiCorp. (April 1, 2024). 2023 Integrated Resource Plan Update. *https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023_IRP_Update.pdf.*

[94] Rocky Mountain Power. (April 1, 2024). Rocky Mountain Power and 8 Rivers to collaborate on proposed Wyoming carbon capture project. Press release. *https://www.rockymountainpower.net/about/newsroom/news-releases/rmp-proposed-wyoming-carbon-capture-project.html.*

[95] Competitive Power Ventures (CPV). Shay Clean Energy Center. *https://www.cpv.com/our-projects/cpv-shay-energy-center/.*

[96] The Associated Press (AP). (August 30, 2023). New owner restarts West Virginia coal-fired power plant and intends to convert it to hydrogen use. *https://apnews.com/article/west-virginia-power-plant-coal-hydrogen-7b46798c8e3b093a8591f25f66340e8f.*

[97] *omnigenglobal.com.*

[98] U.S. Energy Information Administration (EIA). (October 2023). Annual Coal Report 2022. *https://www.eia.gov/coal/annual/pdf/acr.pdf.*

[99] National Energy Technology Laboratory (NETL). Large Pilot Carbon Capture Project Supported by NETL Breaks Ground in Illinois. *https://netl.doe.gov/node/12284.*

suppliers to support additional future projects.[100]

In developing these final rules, the EPA reviewed the current state and cost of CCS technology for use with both steam generating units and stationary combustion turbines. This review is reflected in the respective BSER discussions later in this preamble and is further detailed in the accompanying RIA and final TSDs, *GHG Mitigation Measures for Steam Generating Units* and *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines*. These documents are included in the rulemaking docket.

2. Natural Gas Co-Firing

For a coal-fired steam generating unit, the substitution of natural gas for some of the coal so that the unit fires a combination of coal and natural gas is known as ''natural gas co-firing.'' Existing coal-fired steam generating units can be modified to co-fire natural gas in any desired proportion with coal. Generally, the modification of existing boilers to enable or increase natural gas firing involves the installation of new gas burners and related boiler modifications and may involve the construction of a natural gas supply pipeline if one does not already exist. In recent years, the cost of natural gas co-firing has declined because the expected difference between coal and gas prices has decreased and analysis supports lower capital costs for modifying existing boilers to co-fire with natural gas, as discussed in section VII.C.2.a of this preamble.

It is common practice for steam generating units to have the capability to burn multiple fuels onsite, and of the 565 coal-fired steam generating units operating at the end of 2021, 249 of them reported use of natural gas as a primary fuel or for startup.[101] Based on hourly reported CO_2 emission rates from the start of 2015 through the end of 2020, 29 coal-fired steam generating units co-fired with natural gas at rates at or above 60 percent of capacity on an hourly basis.[102] The capability of those units on an hourly basis is indicative of the extent of boiler burner modifications and sizing and capacity of natural gas pipelines to those units, and it implies that those units are technically capable of co-firing at least 60 percent natural gas on a heat input basis on average over the course of an extended period (*e.g.*, a year). Additionally, many coal-fired steam generating EGUs have also opted to switch entirely to providing generation from the firing of natural gas. Since 2011, more than 80 coal-fired utility boilers have been converted to natural gas-fired utility boilers.[103]

In developing these final actions, the EPA reviewed in detail the current state of natural gas co-firing technology and costs. This review is reflected in the BSER discussions later in this preamble and is further detailed in the accompanying RIA and final TSD, *GHG Mitigation Measures for Steam Generating Units*. Both documents are included in the rulemaking docket.

3. Efficient Generation

Highly efficient generation is the BSER technology upon which the first phase standards of performance are based for certain new and reconstructed stationary combustion turbine EGUs. This technology is available for both simple cycle and combined cycle combustion turbines and has been demonstrated—along with best operating and maintenance practices—to reduce emissions. Generally, as the thermal efficiency of a combustion turbine increases, less fuel is burned per gross MWh of electricity produced and there is a corresponding decrease in CO_2 and other air emissions.

For simple cycle turbines, manufacturers continue to improve the efficiency by increasing firing temperature, increasing pressure ratios, using intercooling on the air compressor, and adopting other measures. Best operating practices for simple cycle turbines include proper maintenance of the combustion turbine flow path components and the use of inlet air cooling to reduce efficiency losses during periods of high ambient temperatures. For combined cycle turbines, a highly efficient combustion turbine engine is matched with a high-efficiency HRSG. High efficiency also includes, but is not limited to, the use of the most efficient steam turbine and minimizing energy losses using insulation and blowdown heat recovery. Best operating and maintenance practices include, but are not limited to, minimizing steam leaks, minimizing air infiltration, and cleaning and maintaining heat transfer surfaces.

As discussed in section VIII.F.2.b of this preamble, efficient generation technologies have been in use at facilities in the power sector for decades and the levels of efficiency that the EPA is finalizing in this rule have been achieved by many recently constructed turbines. The efficiency improvements are incremental in nature and do not change how the combustion turbine is operated or maintained and present little incremental capital or compliance costs compared to other types of technologies that may be considered for new and reconstructed sources. In addition, more efficient designs have lower fuel costs, which offset at least a portion of the increase in capital costs. For additional discussion of this BSER technology, see the final TSD, *Efficient Generation in Combustion Turbines* in the docket for this rulemaking.

Efficiency improvements are also available for fossil fuel-fired steam generating units, and as discussed further in section VII.D.4.a, the more efficiently an EGU operates the less fuel it consumes, thereby emitting lower amounts of CO_2 and other air pollutants per MWh generated. Efficiency improvements for steam generating EGUs include a variety of technology upgrades and operating practices that may achieve CO_2 emission rate reductions of 0.1 to 5 percent for individual EGUs. These reductions are small relative to the reductions that are achievable from natural gas co-firing and from CCS. Also, as efficiency increases, some facilities could increase their utilization and therefore increase their CO_2 emissions (as well as emissions of other air pollutants). This phenomenon is known as the ''rebound effect.'' Because of this potential for perverse GHG emission outcomes resulting from deployment of efficiency measures at certain steam generating units, coupled with the relatively minor overall GHG emission reductions that would be expected, the EPA is not finalizing efficiency improvements as the BSER for any subcategory of existing coal-fired steam generating units. Specific details of efficiency measures are described in the final TSD, *GHG Mitigation Measures for Steam Generating Units*, and an updated 2023 Sargent and Lundy HRI report (*Heat Rate Improvement Method Costs and Limitations Memo*), available in the docket.

[100] Net Power. (March 11, 2024). Q4 2023 Business Update and Results. *https://d1io3yog0oux5.cloudfront.net/_cde4aad258e2cf5aec49abd8654499f8/netpower/db/3583/33195/pdf/Q4_2023+Earnings+Presentation_3.11.24.pdf*.

[101] U.S. Energy Information Administration (EIA). Form 923. *https://www.eia.gov/electricity/data/eia923/*.

[102] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. *https://campd.epa.gov*.

[103] U.S. Energy Information Administration (EIA). (5 August 2020). Today in Energy. More than 100 coal-fired plants have been replaced or converted to natural gas since 2011. *https://www.eia.gov/todayinenergy/detail.php?id=44636*.

D. The Electric Power Sector: Trends and Current Structure

1. Overview

The electric power sector is experiencing 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—especially coal-fired power plants—with more efficient and lower-cost alternatives.

These developments have significant implications for the types of controls that the EPA determined to qualify as the BSER for different types of fossil fuel-fired EGUs. For example, power plant owners and operators retired an average annual coal-fired EGU capacity of 10 GW from 2015 to 2023, and coal-fired EGUs comprised 58 percent of all retired capacity in 2023.[104] While use of CCS promises significant emissions reduction from fossil fuel-fired sources, it requires substantial up-front capital expenditure. Therefore, it is not a feasible or cost-reasonable emission reduction technology for units that intend to cease operation before they would be able to amortize its costs. Industry stakeholders requested that the EPA structure these rules to avoid imposing costly control obligations on coal-fired power plants that have announced plans to voluntarily cease operations, and the EPA has determined the BSER in accordance with its understanding of which coal-fired units will be able to feasibly and cost-effectively deploy the BSER technologies. In addition, the EPA recognizes that utilities and power plant operators are building new natural gas-fired combustion turbines with plans to operate them at varying levels of utilization, in coordination with other existing and expected new energy sources. These patterns of operation are important for the type of controls that the EPA is finalizing as the BSER for these turbines.

2. Broad Trends Within the Power Sector

For more than a decade, the power sector has been experiencing substantial transition and structural change, both in terms of the mix of generating capacity and in the share of electricity generation supplied by different types of EGUs. These changes are the result of multiple factors, including normal replacements of older EGUs; technological improvements in electricity generation from both existing and new EGUs; changes in the prices and availability of different fuels; state and Federal policy; the preferences and purchasing behaviors of end-use electricity consumers; and substantial growth in electricity generation from renewable sources.

One of the most important developments of this transition has been the evolving economics of the power sector. Specifically, as discussed in section IV.D.3.b of this preamble and in the final TSD, *Power Sector Trends,* the existing fleet of coal-fired EGUs continues to age and become more costly to maintain and operate. At the same time, natural gas prices have held relatively low due to increased supply, and renewable costs have fallen rapidly with technological improvement and growing scale. Natural gas surpassed coal in monthly net electricity generation for the first time in April 2015, and since that time natural gas has maintained its position as the primary fuel for base load electricity generation, for peaking applications, and for balancing renewable generation.[105] In 2023, generation from natural gas was more than 2.5 times as much as generation from coal.[106] Additionally, there has been increased generation from investments in zero- and low-GHG emission energy technologies spurred by technological advancements, declining costs, state and Federal policies, and most recently, the IIJA and the IRA. For example, the IIJA provides investments and other policies to help commercialize, demonstrate, and deploy technologies such as small modular nuclear reactors, long-duration energy storage, regional clean hydrogen hubs, CCS and associated infrastructure, advanced geothermal systems, and advanced distributed energy resources (DER) as well as more traditional wind, solar, and battery energy storage resources. The IRA provides numerous tax and other incentives to directly spur deployment of clean energy technologies. Particularly relevant to these final actions, the incentives in the IRA,[107 108] which are discussed in detail later in this section of the preamble, support the expansion of technologies, such as CCS, that reduce GHG emissions from fossil-fired EGUs.

The ongoing transition of the power sector is illustrated by a comparison of data between 2007 and 2022. In 2007, the year of peak coal generation, approximately 72 percent of the electricity provided to the U.S. grid was produced through the combustion of fossil fuels, primarily coal and natural gas, with coal accounting for the largest single share. By 2022, fossil fuel net generation was approximately 60 percent, less than the share in 2007 despite electricity demand remaining relatively flat over this same period. Moreover, the share of generation supplied by coal-fired EGUs fell from 49 percent in 2007 to 19 percent in 2022 while the share supplied by natural gas-fired EGUs rose from 22 to 39 percent during the same period. In absolute terms, coal-fired generation declined by 59 percent while natural gas-fired generation increased by 88 percent. This reflects both the increase in natural gas capacity as well as an increase in the utilization of new and existing natural gas-fired EGUs. The combination of wind and solar generation also grew from 1 percent of the electric power sector mix in 2007 to 15 percent in 2022.[109]

Additional analysis of the utility power sector, including projections of future power sector behavior and the impacts of these final rules, is discussed in more detail in section XII of this preamble, in the accompanying RIA, and in the final TSD, *Power Sector Trends.* The latter two documents are available in the rulemaking docket. Consistent with analyses done by other energy modelers, the information

[104] U.S. Energy Information Administration (EIA). (7 February 2023). Today in Energy. Coal and natural gas plants will account for 98 percent of U.S. capacity retirements in 2023. *https://www.eia.gov/todayinenergy/detail.php?id=55439.*

[105] U.S. Energy Information Administration (EIA). Monthly Energy Review and Short-Term Energy Outlook, March 2016. *https://www.eia.gov/todayinenergy/detail.php?id=25392.*

[106] U.S. Energy Information Administration (EIA). Electric Power Monthly, March 2024. *https://www.eia.gov/electricity/monthly/current_month/march2024.pdf.*

[107] U.S. Department of Energy (DOE). August 2022. *The Inflation Reduction Act Drives Significant Emissions Reductions and Positions America to Reach Our Climate Goals. https://www.energy.gov/sites/default/files/2022-08/8.18%20InflationReductionAct_Factsheet_Final.pdf.*

[108] U.S. Department of Energy (DOE). August 2023. Investing in American Energy. Significant Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Energy Economy and Emissions Reductions. *https://www.energy.gov/sites/default/files/2023-08/DOE%20OP%20Economy%20Wide%20Report_0.pdf.*

[109] U.S. Energy Information Administration (EIA). *Annual Energy Review,* table 8.2b Electricity net generation: electric power sector. *https://www.eia.gov/totalenergy/data/annual/.*

provided in the RIA and TSD demonstrates that the sector trend of moving away from coal-fired generation is likely to continue, the share from natural gas-fired generation is projected to decline eventually, and the share of generation from non-emitting technologies is likely to continue increasing. For instance, according to the Energy Information Administration (EIA), the net change in solar capacity has been larger than the net change in capacity for any other source of electricity for every year since 2020. In 2024, EIA projects that the actual increase in generation from solar will exceed every other source of generating capacity. This is in part because of the large amounts of new solar coming online in 2024 but is also due to the large amount of energy storage coming online, which will help reduce renewable curtailments.[110] EIA also projects that in 2024, the U.S. will see its largest year for installation of both solar and battery storage. Specifically, EIA projects that 36.4 GW of solar will be added, nearly doubling last year's record of 18.4 GW. Similarly, EIA projects 14.3 GW of new energy storage. This would more than double last year's record installation of 6.4 GW and nearly double the existing total capacity of 15.5 GW. This compares to only 2.5 GW of new natural gas turbine capacity.[111] The only year since 2013 when renewable generation did not make up the majority of new generation capacity in the U.S. was 2018.[112]

3. Coal-Fired Generation: Historical Trends and Current Structure

a. Historical Trends in Coal-Fired Generation

Coal-fired steam generating units have historically been the nation's foremost source of electricity, but coal-fired generation has declined steadily since its peak approximately 20 years ago.[113] Construction of new coal-fired steam generating units was at its highest between 1967 and 1986, with approximately 188 GW (or 9.4 GW per year) of capacity added to the grid during that 20-year period.[114] The peak annual capacity addition was 14 GW, which was added in 1980. These coal-fired steam generating units operated as base load units for decades. However, beginning in 2005, the U.S. power sector—and especially the coal-fired fleet—began experiencing a period of transition that continues today. Many of the older coal-fired steam generating units built in the 1960s, 1970s, and 1980s have retired or have experienced significant reductions in net generation due to cost pressures and other factors. Some of these coal-fired steam generating units repowered with combustion turbines and natural gas.[115] With no new coal-fired steam generating units larger than 25 MW commencing construction in the past decade—and with the EPA unaware of any plans being approved to construct a new coal-fired EGU—much of the fleet that remains is aging, expensive to operate and maintain, and increasingly uncompetitive relative to other sources of generation in many parts of the country.

Since 2007, the power sector's total installed net summer capacity[116] has increased by 167 GW (17 percent) while coal-fired steam generating unit capacity has declined by 123 GW.[117] This reduction in coal-fired steam generating unit capacity was offset by a net increase in total installed wind capacity of 125 GW, net natural gas capacity of 110 GW, and a net increase in utility-scale solar capacity of 71 GW during the same period. Additionally, significant amounts (40 GW) of DER solar were also added. At least half of these changes were in the most recent 7 years of this period. From 2015 to 2022, coal capacity was reduced by 90 GW and this reduction in capacity was offset by a net increase of 69 GW of wind capacity, 63 GW of natural gas capacity, and 59 GW of utility-scale solar capacity. Additionally, a net summer capacity of 30 GW of DER solar were added from 2015 to 2022.

b. Current Structure of Coal-Fired Generation

Although much of the fleet of coal-fired steam generating units has historically operated as base load, there can be notable differences in design and operation across various facilities. For example, coal-fired steam generating units smaller than 100 MW comprise 18 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity.[118] Moreover, average annual capacity factors for coal-fired steam generating units have declined from 74 to 50 percent since 2007.[119] These declining capacity factors indicate that a larger share of units are operating in non-base load fashion largely because they are no longer cost-competitive in many hours of the year.

Older power plants also tend to become uneconomic over time as they become more costly to maintain and operate,[120] especially when competing for dispatch against newer and more efficient generating technologies that have lower operating costs. The average coal-fired power plant that retired between 2015 and 2022 was more than 50 years old, and 65 percent of the remaining fleet of coal-fired steam generating units will be 50 years old or more within a decade.[121] To further illustrate this trend, the existing coal-fired steam generating units older than 40 years represent 71 percent (129 GW)[122] of the total remaining capacity. In fact, more than half (100 GW) of the coal-fired steam generating units still operating have already announced retirement dates prior to 2039 or conversion to gas-fired units by the

[110] U.S. Energy Information Administration (EIA). Short Term Energy Outlook, December 2023.

[111] U.S. Energy Information Administration (EIA). (February 15, 2024). Today in Energy. *Solar and Battery Storage to make up 81% of new U.S. Electric-generating capacity in 2024. https://www.eia.gov/todayinenergy/detail.php?id=61424.*

[112] U.S. Energy Information Administration (EIA). Today in Energy. *Natural gas and renewables make up most of 2018 electric capacity additions. https://www.eia.gov/todayinenergy/detail.php?id=36092.*

[113] U.S. Energy Information Administration (EIA). Today in Energy. *Natural gas expected to surpass coal in mix of fuel used for U.S. power generation in 2016.* March 2016. *https://www.eia.gov/todayinenergy/detail.php?id=25392.*

[114] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form EIA–860M, Inventory of Operating Generators and Inventory of Retired Generators, March 2022. *https://www.eia.gov/electricity/data/eia860m/.*

[115] U.S. Energy Information Administration (EIA). Today in Energy. *More than 100 coal-fired plants have been replaced or converted to natural gas since 2011.* August 2020. *https://www.eia.gov/todayinenergy/detail.php?id=44636.*

[116] This includes generating capacity at EGUs primarily operated to supply electricity to the grid and combined heat and power (CHP) facilities classified as Independent Power Producers and excludes generating capacity at commercial and industrial facilities that does not operate primarily as an EGU. Natural gas information reflects data for all generating units using natural gas as the primary fossil heat source unless otherwise stated. This includes combined cycle, simple cycle, steam, and miscellaneous (<1 percent).

[117] U.S. Energy Information Administration (EIA). Electric Power Annuals 2010 (Tables 1.1.A and 1.1.B) and 2022 (Tables 4.2.A and 4.2.B).

[118] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[119] U.S. Energy Information Administration (EIA). Electric Power Annual 2021, table 1.2.

[120] U.S. Energy Information Administration (EIA). U.S. coal plant retirements linked to plants with higher operating costs. December 2019. *https://www.eia.gov/todayinenergy/detail.php?id=42155.*

[121] eGRID 2020 (January 2022 release from EPA eGRID website). Represents data from generators that came online between 1950 and 2020 (inclusive); a 71-year period. Full eGRID data includes generators that came online as far back as 1915.

[122] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form–860M, Inventory of Operating Generators and Inventory of Retired Generators. August 2022. *https://www.eia.gov/electricity/data/eia860m/.*

same year.[123] As discussed later in this section, projections anticipate that this trend will continue.

The reduction in coal-fired generation by electric utilities is also evident in data for annual U.S. coal production, which reflects reductions in international demand as well. In 2008, annual coal production peaked at nearly 1,172 million short tons (MMst) followed by sharp declines in 2015 and 2020.[124] In 2015, less than 900 MMst were produced, and in 2020, the total dropped to 535 MMst, the lowest output since 1965. Following the pandemic, in 2022, annual coal production had increased to 594 MMst. For additional analysis of the coal-fired steam generation fleet, see the final TSD, *Power Sector Trends* included in the docket for this rulemaking.

Notwithstanding these trends, in 2022, coal-fired energy sources were still responsible for 50 percent of CO_2 emissions from the electric power sector.[125]

4. Natural Gas-Fired Generation: Historical Trends and Current Structure

a. Historical Trends in Natural Gas-Fired Generation

There has been significant expansion of the natural gas-fired EGU fleet since 2000, coinciding with efficiency improvements of combustion turbine technologies, increased availability of natural gas, increased demand for flexible generation to support the expanding capacity of variable energy resources, and declining costs for all three elements. According to data from EIA, annual capacity additions for natural gas-fired EGUs peaked between 2000 and 2006, with more than 212 GW added to the grid during this period (about 35 GW per year). Of this total, approximately 147 GW (70 percent) were combined cycle capacity and 65 GW were simple cycle capacity.[126] From 2007 to 2022, more than 132 GW of capacity were constructed and approximately 77 percent of that total were combined cycle EGUs. This figure represents an average of almost 8.8 GW of new combustion turbine generation capacity per year. In 2022, the net summer capacity of combustion turbine EGUs totaled 419 GW, with 289 GW being combined cycle generation and 130 GW being simple cycle generation.

This trend away from electricity generation using coal-fired EGUs to natural gas-fired turbine EGUs is also reflected in comparisons of annual capacity factors, sizes, and ages of affected EGUs. For example, the average annual capacity factors for natural gas-fired units increased from 28 to 38 percent between 2010 and 2022. And compared with the fleet of coal-fired steam generating units, the natural gas fleet is generally smaller and newer. While 67 percent of the coal-fired steam generating unit fleet capacity is over 500 MW per unit, 75 percent of the gas fleet is between 50 and 500 MW per unit. In terms of the age of the generating units, nearly 50 percent of the natural gas capacity has been in service less than 15 years.[127]

b. Current Structure of Natural Gas-Fired Generation

In the lower 48 states, most combustion turbine EGUs burn natural gas, and some have the capability to fire distillate oil as backup for periods when natural gas is not available, such as when residential demand for natural gas is high during the winter. Areas of the country without access to natural gas often use distillate oil or some other locally available fuel. Combustion turbines have the capability to burn either gaseous or liquid fossil fuels, including but not limited to kerosene, naphtha, synthetic gas, biogases, liquified natural gas (LNG), and hydrogen.

Over the past 20 years, advances in hydraulic fracturing (*i.e.*, fracking) and horizontal drilling techniques have opened new regions of the U.S. to gas exploration. As the production of natural gas has increased, the annual average price has declined during the same period, leading to more natural gas-fired combustion turbines.[128] Natural gas net generation increased 181 percent in the past two decades, from 601 thousand gigawatt-hours (GWh) in 2000 to 1,687 thousand GWh in 2022. For additional analysis of natural gas-fired generation, see the final TSD, *Power Sector Trends* included in the docket for this rulemaking.

E. The Legislative, Market, and State Law Context

1. Recent Legislation Impacting the Power Sector

On November 15, 2021, President Biden signed the IIJA[129] (also known as the Bipartisan Infrastructure Law), which allocated more than $65 billion in funding via grant programs, contracts, cooperative agreements, credit allocations, and other mechanisms to develop and upgrade infrastructure and expand access to clean energy technologies. Specific objectives of the legislation are to improve the nation's electricity transmission capacity, pipeline infrastructure, and increase the availability of low-GHG fuels. Some of the IIJA programs[130] that will impact the utility power sector include more than $20 billion to build and upgrade the nation's electric grid, up to $6 billion in financial support for existing nuclear reactors that are at risk of closing, and more than $700 million for upgrades to the existing hydroelectric fleet. The IIJA established the Carbon Dioxide Transportation Infrastructure Finance and Innovation Program to provide flexible Federal loans and grants for building CO_2 pipelines designed with excess capacity, enabling integrated carbon capture and geologic storage. The IIJA also allocated $21.5 billion to fund new programs to support the development, demonstration, and deployment of clean energy technologies, such as $8 billion for the development of regional clean hydrogen hubs and $7 billion for the development of carbon management technologies, including regional direct air capture hubs, carbon capture large-scale pilot projects for development of transformational technologies, and carbon capture commercial-scale demonstration projects to improve efficiency and effectiveness. Other clean energy technologies with IIJA and IRA funding include industrial demonstrations, geologic sequestration, grid-scale energy storage, and advanced nuclear reactors.

The IRA, which President Biden signed on August 16, 2022,[131] has the potential for even greater impacts on the electric power sector. Energy Security and Climate Change programs in the

[123] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v6. October 2022. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs*.

[124] U.S. Energy Information Administration (EIA). (October 2023). Annual Coal Report 2022. *https://www.eia.gov/coal/annual/pdf/acr.pdf*.

[125] U.S. Energy Information Administration (EIA). U.S. CO_2 emissions from energy consumption by source and sector, 2022. *https://www.eia.gov/totalenergy/data/monthly/pdf/flow/CO2_emissions_2022.pdf*.

[126] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form EIA–860M, Inventory of Operating Generators and Inventory of Retired Generators, July 2022. *https://www.eia.gov/electricity/data/eia860m/*.

[127] National Electric Energy Data System (NEEDS) v.6.

[128] U.S. Energy Information Administration (EIA). *Natural Gas Annual*, September 2021. *https://www.eia.gov/energyexplained/natural-gas/prices.php*.

[129] *https://www.congress.gov/bill/117th-congress/house-bill/3684/text*.

[130] *https://www.whitehouse.gov/wp-content/uploads/2022/05/BUILDING-A-BETTER-AMERICA-V2.pdf*.

[131] *https://www.congress.gov/bill/117th-congress/house-bill/5376/text*.

IRA covering grant funding and tax incentives provide significant investments in low and non GHG-emitting generation. For example, one of the conditions set by Congress for the expiration of the Clean Electricity Production Tax Credits of the IRA, found in section 13701, is a 75 percent reduction in GHG emissions from the power sector below 2022 levels. The IRA also contains the Low Emission Electricity Program (LEEP) with funding provided to the EPA with the objective to reduce GHG emissions from domestic electricity generation and use through promotion of incentives, tools to facilitate action, and use of CAA regulatory authority. In particular, CAA section 135, added by IRA section 60107, requires the EPA to conduct an assessment of the GHG emission reductions expected to occur from changes in domestic electricity generation and use through fiscal year 2031 and, further, provides the EPA $18 million ''to ensure that reductions in [GHG] emissions are achieved through use of the existing authorities of [the Clean Air Act], incorporating the assessment. . . .'' CAA section 135(a)(6).

The IRA's provisions also demonstrate an intent to support development and deployment of low-GHG emitting technologies in the power sector through a broad array of additional tax credits, loan guarantees, and public investment programs. Particularly relevant for these final actions, these provisions are aimed at reducing emissions of GHGs from new and existing generating assets, with tax credits for CCUS and clean hydrogen production, providing a pathway for the use of coal and natural gas as part of a low-GHG electricity grid.

To assist states and utilities in their decarbonizing efforts, and most germane to these final actions, the IRA increased the tax credit incentives for capturing and storing CO_2, including from industrial sources, coal-fired steam generating units, and natural gas-fired stationary combustion turbines. The increase in credit values, found in section 13104 (which revises IRC section 45Q), is 70 percent, equaling $85/metric ton for CO_2 captured and securely stored in geologic formations and $60/metric ton for CO_2 captured and utilized or securely stored incidentally in conjunction with EOR.[132] The CCUS incentives include 12 years of credits that can be claimed at the higher credit value beginning in 2023 for qualifying projects. These incentives will significantly cut costs and are expected to accelerate the adoption of CCS in the utility power and other industrial sectors. Specifically for the power sector, the IRA requires that a qualifying carbon capture facility have a CO_2 capture design capacity of not less than 75 percent of the baseline CO_2 production of the unit and that construction must begin before January 1, 2033. Tax credits under IRC section 45Q can be combined with some other tax credits, in some circumstances, and with state-level incentives, including California's low carbon fuel standard, which is a market-based program with fuel-specific carbon intensity benchmarks.[133] The magnitude of this incentive is driving investment and announcements, evidenced by the increased number of permit applications for geologic sequestration.[134]

The new provisions in section 13204 (IRC section 45V) codify production tax credits for 'clean hydrogen' as defined in the provision. The value of the credits earned by a project is tiered (four different tiers) and depends on the estimated GHG emissions of the hydrogen production process as defined in the statute. The credits range from $3/kg H_2 for less than 0.45 kilograms of CO_2-equivalent emitted per kilogram of low-GHG hydrogen produced (kg CO_2e/kg H_2) down to $0.6/kg H_2 for 2.5 to 4.0 kg CO_2e/kg H_2 (assuming wage and apprenticeship requirements are met). Projects with production related GHG emissions greater than 4.0 kg CO_2e/kg H_2 are not eligible. Future costs for clean hydrogen produced using renewable energy are anticipated to through 2030 due to these tax incentives and concurrent scaling up of manufacturing and deployment of clean hydrogen production facilities.

Both IRC section 45Q and IRC section 45V are eligible for additional provisions that increase the value and usability of the credits. Certain tax-exempt entities, such as electric co-operatives, may elect direct payment for the full 12- or 10-year lifetime of the credits to monetize the credits directly as cash refunds rather than through tax equity transactions. Tax-paying entities may elect to have direct payment of IRC section 45Q or 45V credits for 5 consecutive years. Tax-paying entities may also elect to transfer credits to unrelated taxpayers, enabling direct monetization of the credits again without relying on tax equity transactions.

In addition to provisions such as 45Q that allow for the use of fossil-generating assets in a low-GHG future, the IRA also includes significant incentives to deploy clean energy generation. For instance, the IRA provides an additional 10 percent in production tax credit (PTC) and investment tax credit (ITC) bonuses for clean energy projects located in energy communities with historic employment and tax bases related to fossil fuels.[135] The IRA's Energy Infrastructure Reinvestment Program also provides $250 billion for the DOE to finance loan guarantees that can be used to reduce both the cost of retiring existing fossil assets and of replacement generation for those assets, including updating operating energy infrastructure with emissions control technologies.[136] As a further example, the Empowering Rural America (New ERA) Program provides rural electric cooperatives with funds that can be used for a variety of purposes, including ''funding for renewable and zero emissions energy systems that eliminate aging, obsolete or expensive infrastructure'' or that allow rural cooperatives to ''change [their] purchased-power mixes to support cleaner portfolios, manage stranded assets and boost [the] transition to clean energy.'' [137] The $9.7 billion New ERA program represents the single largest investment in rural energy systems since the Rural Electrification Act of 1936.[138]

On September 12, 2023, the EPA released a report assessing the impact of the IRA on the power sector. Modeling results showed that economy-wide CO_2 emissions are lower under the IRA. The

[132] 26 U.S.C. 45Q. Note, qualified facilities must meet prevailing wage and apprenticeship requirements to be eligible for the full value of the tax credit.

[133] Global CCS Institute. (2019). *The LCFS and CCS Protocol: An Overview for Policymakers and Project Developers.* Policy report. *https://www.globalccsinstitute.com/wp-content/uploads/2019/05/LCFS-and-CCS-Protocol_digital_version-2.pdf.*

[134] EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[135] U.S. Department of the Treasury. (April 4, 2023). Treasury Releases Guidance to Drive Investment to Coal Communities. Press release. *https://home.treasury.gov/news/press-releases/jy1383.*

[136] Fong, C., Posner, D., Varadarajan, U. (February 16, 2024). The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy. Case studies from Missouri and Iowa. Rocky Mountain Institute (RMI). *https://rmi.org/the-energy-infrastructure-reinvestment-program-federal-financing-for-an-equitable-clean-economy/.*

[137] U.S. Department of Agriculture (USDA). Empowering Rural America New ERA Program. *https://www.rd.usda.gov/programs-services/electric-programs/empowering-rural-america-new-era-program.*

[138] Rocky Mountain Institute (RMI). (October 4, 2023). USDA $9.7B Rural Community Clean Energy Program Receives 150+ Letters of Interest. Press release. *https://rmi.org/press-release/usda-9-7b-rural-community-clean-energy-program-receives-150-letters-of-interest/.*

results from the EPA's analysis of an array of multi-sector and electric sector modeling efforts show that a wide range of emissions reductions are possible. The IRA spurs CO_2 emissions reductions from the electric power sector of 49 to 83 percent below 2005 levels in 2030. This finding reflects diversity in how the models represent the IRA, the assumptions the models use, and fundamental differences in model structures.[139]

In determining the CAA section 111 emission limitations that are included in these final actions, the EPA did not consider many of the technologies that receive investment under recent Federal legislation. The EPA's determination of the BSER focused on ''measures that improve the pollution performance of individual sources,'' [140] not generation technologies that entities could employ as alternatives to fossil fuel-fired EGUs. However, these overarching incentives and policies are important context for this rulemaking and influence where control technologies can be feasibly and cost-reasonably deployed, as well as how owners and operators of EGUs may respond to the requirements of these final actions.

2. Commitments by Utilities To Reduce GHG Emissions

Integrated resource plans (IRPs) are filed by public utilities and demonstrate how utilities plan to meet future forecasted energy demand while ensuring reliable and cost-effective service. In developing these rules, the EPA reviewed filed IRPs of companies that have publicly committed to reducing their GHGs. These IRPs demonstrate a range of strategies that public utilities are planning to adopt to reduce their GHGs, independent of these final actions. These strategies include retiring aging coal-fired steam generating EGUs and replacing them with a combination of renewable resources, energy storage, other non-emitting technologies, and natural gas-fired combustion turbines, and reducing GHGs from their natural gas-fired assets through a combination of CCS and reduced utilization. To affirm these findings, according to EIA, as of 2022 there are no new coal-fired EGUs in development. This section highlights recent actions and announced plans of many utilities across the industry to reduce GHGs from their fleets. Indeed, 50 power producers that are members of the Edison Electric Institute (EEI) have announced CO_2 reduction goals, two-thirds of which include net-zero carbon emissions by 2050.[141] The members of the Energy Strategies Coalition, a group of companies that operate and manage electricity generation facilities, as well as electricity and natural gas transmission and distribution systems, likewise are focused on investments to reduce carbon dioxide emissions from the electricity sector.[142] This trend is not unique. Smaller utilities, rural electric cooperatives, and municipal entities are also contributing to these changes.

Many electric utilities have publicly announced near- and long-term emission reduction commitments independent of these final actions. The Smart Electric Power Alliance demonstrates that the geographic footprint of commitments for 100 percent renewable, net-zero, or other carbon emission reductions by 2050 made by utilities, their parent companies, or in response to a state clean energy requirement, covers portions of 47 states and includes 80 percent of U.S. customer accounts.[143] According to this same source, 341 utilities in 26 states have similar commitments by 2040. Additional detail about emission reduction commitments from major utilities is provided in section 2.2 of the RIA and in the final TSD, *Power Sector Trends*.

3. State Actions To Reduce Power Sector GHG Emissions

States across the country have taken the lead in efforts to reduce GHG emissions from the power sector. As of mid-2023, 25 states had made commitments to reduce economy-wide GHG emissions consistent with the goals of the Paris Agreement, including reducing GHG emissions by 50 to 52 percent by 2030.[144] [145] [146] These actions include legislation to decarbonize state power systems as well as commitments that require utilities to expand renewable and clean energy production through the adoption of renewable portfolio standards (RPS) and clean energy standards (CES).

Several states have enacted binding economy-wide emission reduction targets that will require significant decarbonization from state power sectors, including California, Colorado, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, Vermont, and Washington.[147] These commitments are statutory emission reduction targets accompanied by mandatory agency directives to develop comprehensive implementing regulations to achieve the necessary reductions. Some of these states, along with other neighboring states, also participate in the Regional Greenhouse Gas Initiative (RGGI), a carbon market limiting pollution from power plants throughout New England.[148] The pollution limit combined with carbon price and allowance market has led member states to reduce power sector CO_2 emissions by nearly 50 percent since the start of the program in 2009. This is 10 percent more than all non-RGGI states.[149]

Other states dependent on coal-fired power generation or coal production also have significant, albeit non-

[139] U.S. Environmental Protection Agency (EPA). (September 2023). *Electricity Sector Emissions Impacts of the Inflation Reduction Act. https://www.epa.gov/system/files/documents/2023-09/Electricity_Emissions_Impacts_Inflation_Reduction_Act_Report_EPA-FINAL.pdf.*

[140] *West Virginia* v. *EPA,* 597 U.S. at 734.

[141] See Comments of Edison Electric Institute to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, Document ID No. EPA–HQ–OAR–2022–0723–0024, November 18, 2022 (''Fifty EEI members have announced forward-looking carbon reduction goals, two-third of which include a net-zero by 2050 or earlier equivalent goal, and members are routinely increasing the ambition or speed of their goals or altogether transforming them into net-zero goals.'').

[142] Energy Strategy Coalition Comments on EPA'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, Document ID No. EPA–HQ–OAR–2023–0072–0672, August 14, 2023.

[143] Smart Electric Power Alliance Utility Carbon Tracker. *https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.*

[144] Cao, L., Brindle., T., Schneer, K., and DeGolia, A. (December 2023). Turning Climate Commitments into Results: Evaluating Updated 2023 Projections vs. State Climate Targets. Environmental Defense Fund (EDF). *https://www.edf.org/sites/default/files/2023–11/EDF-State-Emissions-Gap-December-2023.pdf.*

[145] United Nations Framework Convention on Climate Change. What is the Paris Agreement? *https://unfccc.int/process-and-meetings/the-paris-agreement.*

[146] U.S. Department of State and U.S. Executive Office of the President. November 2021. The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050. *https://www.whitehouse.gov/wp-content/uploads/2021/10/us-long-term-strategy.pdf.*

[147] Cao, L., Brindle., T., Schneer, K., and DeGolia, A., December 2023. Turning Climate Commitments into Results: Evaluating Updated 2023 Projections vs. State Climate Targets. Environmental Defense Fund (EDF). *https://www.edf.org/sites/default/files/2023-11/EDF-State-Emissions-Gap-December-2023.pdf.*

[148] A full list of states currently participating in RGGI include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

[149] Note that these figures do not include Virginia and Pennsylvania, which were not members of RGGI for the full duration of 2009–2023. Acadia Center: Regional Greenhouse Gas Initiative; Findings and Recommendations for the Third Program Review. *https://acadiacenter.wpenginepowered.com/wp-content/uploads/2023/04/AC_RGGI_2023_Layout_R6.pdf.*

binding, commitments that signal broad public support for policy with emissions-based metrics and public affirmation that climate change is fundamentally linked to fossil-intensive energy sources. These states include Illinois, Michigan, Minnesota, New Mexico, North Carolina, Pennsylvania, and Virginia. States like Wyoming, the top coal producing state in the U.S., have promulgated sector-specific regulations requiring their public service commissions to implement low-carbon energy standards for public utilities.[150] [151] Specific standards are further detailed in the sections that follow and in the final TSD, *Power Sector Trends*.

Technologies like CCS provide a means to achieve significant emission reduction targets. For example, to achieve GHG emission reduction goals legislatively enacted in 2016, California Senate Bill 100, passed in 2018, requires the state to procure 60 percent of all electricity from renewable sources by 2030 and plan for 100 percent from carbon-free sources by 2045.[152] Achieving California's established goal of carbon-free electricity by 2045 requires emissions to be balanced by carbon sequestration, capture, or other technologies. Therefore, California Senate Bill 905, passed in 2022, requires the California Air Resources Board (CARB) to establish programs for permitting CCS projects while preventing the use of captured CO_2 for EOR within the state.[153] As mentioned previously, as the top coal producing state, Wyoming has been exceptionally persistent on the implementation of CCS by incentivizing the national testing of CCS at Basin Electric's coal-fired Dry Fork Station[154] and by requiring the consideration of CCS as an alternative to coal plant retirement.[155] At least five other states, including Montana and North Dakota, also have tax incentives and regulations for CCS.[156] In the case of Montana, the acquisition of an equity interest or lease of coal-fired EGUs is prohibited unless it captures and stores at least 50 percent of its CO_2 emissions.[157] These state policies have coincided with the planning and development of large CCS projects.

Other states have broad decarbonization laws that will drive significant decrease in power sector GHG emissions. In New York, The Climate Leadership and Community Protection Act, passed in 2019, sets several climate targets. The most important goals include an 85 percent reduction in GHG emissions by 2050, 100 percent zero-emission electricity by 2040, and 70 percent renewable energy by 2030. Other targets include 9,000 MW of offshore wind by 2035, 3,000 MW of energy storage by 2030, and 6,000 MW of solar by 2025.[158] Washington State's Climate Commitment Act sets a target of reducing GHG emissions by 95 percent by 2050. The state is required to reduce emissions to 1990 levels by 2020, 45 percent below 1990 levels by 2030, 70 percent below 1990 levels by 2040, and 95 percent below 1990 levels by 2050. This also includes achieving net-zero emissions by 2050.[159] Illinois' Climate and Equitable Jobs Act, enacted in September 2021, requires all private coal-fired or oil-fired power plants to reach zero carbon emissions by 2030, municipal coal-fired plants to reach zero carbon emissions by 2045, and natural gas-fired plants to reach zero carbon emissions by 2045.[160] In October 2021, North Carolina passed House Bill 951 that required the North Carolina Utilities Commission to "take all reasonable steps to achieve a seventy percent (70 percent) reduction in emissions of carbon dioxide (CO_2) emitted in the state from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050." [161]

The ambition and scope of these state power sector polices will impact the electric generation fleet for decades. Seven states with 100-percent power sector decarbonization polices include a total of 20 coal-fired EGUs with slightly less than 10 GW total capacity and without announced retirement dates before 2039.[162] Virginia, which has three coal-steam units with no announced retirement dates and one with a 2045 retirement date, enacted the Clean Economy Act in 2020 to impose a 100 percent RPS requirement by 2050. The combined capacity of all four of these units in Virginia totals nearly 1.5 GW. North Carolina, which has one coal-fired unit without an announced retirement date and one with a planned 2048 retirement, as previously mentioned, enacted a state law in 2021 requiring the state's utilities commission to achieve carbon neutrality by 2050. The combined capacity of both units totals approximately 1.4 GW of capacity. Nebraska, where three public utility boards serving a large portion of the state have adopted net-zero electricity emission goals by 2040 or 2050, includes six coal-fired units with a combined capacity of 2.9 GW. The remaining eight units are in states with long-term decarbonization goals (Illinois, Louisiana, Maryland, and Wisconsin). All four of these states have set 100 percent clean energy goals by 2050.

Twenty-nine states and the District of Columbia have enforceable RPS [163] that require a percentage of electricity that utilities sell to come from eligible renewable sources like wind and solar rather than from fossil fuel-based sources like coal and natural gas. Furthermore, 20 states have adopted a CES that includes some form of clean

[150] State of Wyoming. (Adopted March 24, 2020). House Bill 200 Reliable and dispatchable low-carbon energy standards. *https://www.wyoleg.gov/Legislation/2020/HB0200*.

[151] State of Wyoming. (Adopted March 15, 2024). Senate Bill 42 Low-carbon reliable energy standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042*.

[152] Berkeley Law. *California Climate Policy Dashboard. https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard*.

[153] Berkeley Law. *California Climate Policy Dashboard. https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard*.

[154] Basin Electric Power Cooperative. (May 2023). Press Release: Carbon Capture Technology Developers Break Ground at Wyoming Integrated Test Center Located at Basin Electric's Dry Fork Station. *https://www.basinelectric.com/News-Center/news-briefs/Carbon-capture-technology-developers-break-ground-at-Wyoming-Integrated-Test-Center-located-at-Basin-Electrics-Dry-Fork-Station*.

[155] State of Wyoming. (Adopted March 15, 2024). Senate Bill 42 Low-carbon reliable energy standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042*.

[156] Sabin Center for Climate Change Law. 2019. Legal Pathways to Deep Decarbonization. Interactive Tracker for State Action on Carbon Capture. *https://cdrlaw.org/ccus-tracker/*.

[157] Sabin Center for Climate Change Law. 2019. Legal Pathways to Deep Decarbonization. Model Laws. Montana prohibition on acquiring coal plants without CCS. *https://lpdd.org/resources/montana-prohibition-on-acquiring-coal-plants-without-ccs/*.

[158] New York State. Climate Act: Progress to our Goals. *https://climate.ny.gov/Our-Impact/Our-Progress*.

[159] Department of Ecology Washington State. *Greenhouse Gases. https://ecology.wa.gov/Air-Climate/Climate-change/Tracking-greenhouse-gases*.

[160] State of Illinois General Assembly. Public Act 102–0662: Climate and Equitable Jobs Act. 2021. *https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf*.

[161] General Assembly of North Carolina, House Bill 951 (2021). *https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951v5.pdf*.

[162] These estimates are based on an analysis of the EPA's NEEDS database, which contains information about EGUs across the country. The analysis includes a basic screen for units within the NEEDS database that are likely subject to the final 111(d) EGU rule, namely coal-steam units with capacity greater than 25 MW, and then removes units with an announced retirement dates prior to 2039, units with announced plans to convert from coal- to gas-fired units, and units likely to fall outside of the rule's applicability via the cogeneration exemption.

[163] DSIRE, Renewable Portfolio Standards and Clean Energy Standards (2023). *https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2023/12/RPS-CES-Dec2023-1.pdf;* LBNL, *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update. https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean*.

energy requirement or goal with a 100 percent or net-zero target.[164] A CES shifts generating fleets away from fossil fuel resources by requiring a percentage of retail electricity to come from sources that are defined as clean. Unlike an RPS, which defines eligible generation in terms of the renewable attributes of its energy source, CES eligibility is based on the GHG emission attributes of the generation itself, typically with a zero or net-zero carbon emissions requirement. Additional discussion of state actions and legislation to reduce GHG emissions from the power sector is provided in the final TSD, *Power Sector Trends*.

F. Future Projections of Power Sector Trends

Projections for the U.S. power sector—based on the landscape of market forces in addition to the known actions of Congress, utilities, and states—have indicated that the ongoing transition will continue for specific fuel types and EGUs. The EPA's Power Sector Platform 2023 using IPM reference case (*i.e.*, the EPA's projections of the power sector, which includes representation of the IRA absent further regulation), provides projections out to 2050 on future outcomes of the electric power sector. For more information on the details of this modeling, see the model documentation.[165]

Since the passage of the IRA in August 2022, the EPA has engaged with many external partners, including other governmental entities, academia, non-governmental organizations (NGOs), and industry, to understand the impacts that the IRA will have on power sector GHG emissions. In addition to engaging in several workgroups, the EPA has contributed to two separate journal articles that include multi-model comparisons of IRA impacts across several state-of-the-art models of the U.S. energy system and electricity sector[166] [167] and participated in public events exploring modeling assumptions for the IRA.[168] The EPA plans to continue collaborating with stakeholders, conducting external engagements, and using information gathered to refine modeling of the IRA.

While much of the discussion below focuses on the EPA's Power Sector Platform 2023 using IPM reference case, many other analyses show similar trends,[169] and these trends are consistent with utility IRPs and public GHG reduction commitments, as well as state actions, both of which were described in the previous sections.

1. Future Projections for Coal-Fired Generation

As described in the EPA's baseline modeling, coal-fired steam generating unit capacity is projected to fall from 181 GW in 2023[170] to 52 GW in 2035, of which 11 GW includes retrofit CCS. Generation from coal-fired steam generating units is projected to also fall from 898 thousand GWh in 2021[171] to 236 thousand GWh by 2035. This change in generation reflects the anticipated continued decline in projected coal-fired steam generating unit capacity as well as a steady decline in annual operation of those EGUs that remain online, with capacity factors falling from approximately 48 percent in 2022 to 45 percent in 2035 at facilities that do not install CCS. By 2050, coal-fired steam generating unit capacity is projected to diminish further, with only 28 GW, or less than 16 percent of 2023 capacity (and approximately 9 percent of the 2010 capacity), still in operation across the continental U.S.

These projections are driven by the eroding economic opportunities for coal-fired steam generating units to operate, the continued aging of the fleet of coal-fired steam generating units, and the continued availability and expansion of low-cost alternatives, like natural gas, renewable technologies, and energy storage. The projected retirements continue the trend of coal plant retirements in recent decades that is described in section IV.D.3. of this preamble (and further in the *Power Sector Trends* technical support document). The decline in coal generation capacity has generally resulted from a more competitive economic environment and increasing coal plant age. Most notably, declines in natural gas prices associated with the rise of hydraulic fracturing and horizontal drilling lowered the cost of natural gas-fired generation.[172] Lower gas generation costs reduced coal plant capacity factors and revenues. Rapid declines in the costs of renewables and battery storage have put further price pressure on coal plants, given the zero marginal cost operation of solar and wind.[173] [174] [175] In addition, most operational coal plants today were built before 2000, and many are reaching or have surpassed their expected useful lives.[176] Retiring coal plants tend to be

[164] This count is adapted from Lawrence Berkeley National Laboratory's (LBNL) *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update,* which identifies 15 states with 100 percent CES. The LBNL count includes Virginia, which the EPA omits because it considers Virginia a 100 percent RPS. Further, the LBNL count excludes Louisiana, Michigan, New Jersey, and Wisconsin because their clean energy goals are set by executive order. The EPA instead includes Louisiana, New Jersey, and Wisconsin but characterizes them as goals rather than requirements. Michigan, which enacted a CES by statute after the LBNL report's publication, is also included in the EPA count. Finally, the EPA count includes Maryland, whose December 2023 *Climate Pollution Reduction Plan* sets a goal of 100 percent clean energy by 2035, and Delaware, which enacted a statutory goal to reach net-zero GHG emissions by 2050. See LBNL, *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update, https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean*; *Maryland's Climate Pollution Reduction Plan, https://mde.maryland.gov/programs/air/ClimateChange/Maryland%20Climate%20Reduction%20Plan/Maryland%27s%20Climate%20Pollution%20Reduction%20Plan%20-%20Final%20-%20Dec%2028%202023.pdf*; and *HB 99, An Act to Amend Titles 7 and 29 of the Delaware Code Relating to Climate Change, https://legis.delaware.gov/json/BillDetail/GenerateHtmlDocumentEngrossment?engrossmentId=25785&docTypeId=6.*

[165] U.S. Environmental Protection Agency. *Power Sector Platform 2023 using IPM.* April 2024. *https://www.epa.gov/power-sector-modeling.*

[166] Bistline, *et al.* (2023). "Emissions and Energy System Impacts of the Inflation Reduction Act of 2022." *https://www.science.org/stoken/author-tokens/ST-1277/full.*

[167] Bistline, *et al.* (2023). "Power Sector Impacts of the Inflation Reduction Act of 2022." *https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b.*

[168] Resource for the Future (2023). "Future Generation: Exploring the New Baseline for Electricity in the Presence of the Inflation Reduction Act." *https://www.rff.org/events/rff-live/future-generation-exploring-the-new-baseline-for-electricity-in-the-presence-of-the-inflation-reduction-act/.*

[169] A wide variety of modeling teams have assessed baselines with IRA. The baseline estimated here is generally in line with these other estimates. Bistline, *et al.* (2023). "Power Sector Impacts of the Inflation Reduction Act of 2022." *https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b.*

[170] U.S. Energy Information Administration (EIA), Preliminary Monthly Electric Generator Inventory, December 2023. *https://www.eia.gov/electricity/data/eia860m/*

[171] U.S. Energy Information Administration (EIA), Electric Power Annual, table 3.1.A. November 2022. *https://www.eia.gov/electricity/annual/.*

[172] International Energy Agency (IEA). Energy Policies of IEA Countries: United States 2019 Review. *https://iea.blob.core.windows.net/assets/7c65c270-ba15-466a-b50d-1c5cd19e359c/United_States_2019_Review.pdf.*

[173] U.S. Energy Information Administration (EIA). (April 13, 2023). U.S. Electric Capacity Mix shifts from Fossil Fuels to Renewables in AEO2023. *https://www.eia.gov/todayinenergy/detail.php?id=56160.*

[174] Solomon, M., et al. (January 2023). Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment. Energy Innovation. *https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.*

[175] Barbose, G., et al. (September 2023). Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, 2023 Edition. Lawrence Berkeley National Laboratory. *https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.*

[176] U.S. Energy Information Administration (EIA). (August 2022). Electric Generators Inventory, Form–860M, Inventory of Operating Generators and Inventory of Retired Generators. *https://www.eia.gov/electricity/data/eia860m/.*

old.[177] As plants age, their efficiency tends to decline and operations and maintenance costs increase. Older coal plant operational parameters are less aligned with current electric grid needs. Coal plants historically were used as base load power sources and can be slow (or expensive) to increase or decrease generation output throughout a typical day. That has put greater economic pressure on older coal plants, which are forced to either incur the costs of adjusting their generation or operate during less profitable hours when loads are lower or renewable generation is more plentiful.[178] All of these factors have contributed to retirements over the past 15 years, and similar underlying factors are projected to continue the trend of coal retirements in the coming years.

In 2020, there was a total of 1,439 million metric tons of CO_2 emissions from the power sector with coal-fired sources contributing to more than half of those emissions. In the EPA's Power Sector Platform 2023 using IPM reference case, power sector related CO_2 emission are projected to fall to 724 million metric tons by 2035, of which 23 percent is projected to come from coal-fired sources in 2035.

2. Future Projections for Natural Gas-Fired Generation

As described in the EPA's Power Sector Platform 2023 using IPM reference case, natural gas-fired capacity is expected to continue to build out during the next decade with 34 GW of new capacity projected to come online by 2035 and 261 GW of new capacity by 2050. By 2035, the new natural gas capacity is comprised of 14 GW of simple cycle turbines and 20 GW of combined cycle turbines. By 2050, most of the incremental new capacity is projected to come just from simple cycle turbines. This also represents a higher rate of new simple cycle turbine builds compared to the reference periods (*i.e.*, 2000–2006 and 2007–2021) discussed previously in this section.

It should be noted that despite this increase in capacity, both overall generation and emissions from the natural gas-fired capacity are projected to decline. Generation from natural gas units is projected to fall from 1,579 thousand GWh in 2021[179] to 1,344 thousand GWh by 2035. Power sector related CO_2 emissions from natural gas-fired EGUs were 615 million metric tons in 2021.[180] By 2035, emission levels are projected to reach 521 million metric tons, 96 percent of which comes from NGCC sources.

The decline in generation and emissions is driven by a projected decline in NGCC capacity factors. In model projections, NGCC units have a capacity factor early in the projection period of 59 percent, but by 2035, capacity factor projections fall to 48 percent as many of these units switch from base load operation to more intermediate load operation to support the integration of variable renewable energy resources. Natural gas-fired simple cycle turbine capacity factors also fall, although since they are used primarily as a peaking resource and their capacity factors are already below 10 percent annually, their impact on generation and emissions changes are less notable.

Some of the reasons for this anticipated continued growth in natural gas-fired capacity, coupled with a decline in generation and emissions, include the anticipated growth in peak load, retirement of older fossil generators, and growth in renewable energy coupled with the greater flexibility offered by combustion turbines. Simple cycle turbines operate at lower efficiencies than NGCC units but offer fast startup times to meet peaking load demands. In addition, combustion turbines, along with energy storage technologies and demand response strategies, support the expansion of renewable electricity by meeting demand during peak periods and providing flexibility around the variability of renewable generation and electricity demand. In the longer term, as renewables and battery storage grow, they are anticipated to outcompete the need for some natural gas-fired generation and the overall utilization of natural gas-fired capacity is expected to decline. For additional discussion and analysis of projections of future coal- and natural gas-fired generation, see the final TSD, *Power Sector Trends* in the docket for this rulemaking.

As explained in greater detail later in this preamble and in the accompanying RIA, future generation projections for natural gas-fired combustion turbines differ from those highlighted in recent historical trends. The largest source of new generation is from renewable energy, and projections show that total natural gas-fired combined cycle capacity is likely to decline after 2030 in response to increased generation from renewables, deployment of energy storage, and other technologies. Approximately 95 percent of capacity additions in 2024 are expected to be from non-emitting generation resources including solar, battery storage, wind, and nuclear.[181] The IRA is likely to influence this trend, which is also expected to impact the operation of certain combustion turbines. For example, as the electric output from additional variable renewable generating sources fluctuates daily and seasonally, flexible low and intermediate load combustion turbines will be needed to support these variable sources and provide reliability to the grid. This requires the ability to start and stop quickly and change load more frequently. Today's system includes 212 GW of intermediate and low load combustion turbines. These operational changes, alongside other tools like demand response, energy storage, and expanded transmission, will maintain reliability of the grid.

V. Statutory Background and Regulatory History for CAA Section 111

A. Statutory Authority To Regulate GHGs From EGUs Under CAA Section 111

The EPA's authority for and obligation to issue these final rules is CAA section 111, which establishes mechanisms for controlling emissions of air pollutants from new and existing stationary sources. CAA section 111(b)(1)(A) requires the EPA Administrator to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, and distinguish among classes, types, and sizes within categories in establishing the standards.

[177] Mills, A., et al. (November 2017). Power Plant Retirements: Trends and Possible Drivers. Lawrence Berkeley National Laboratory. *https://live-etabiblio.pantheonsite.io/sites/default/files/lbnl_retirements_data_synthesis_final.pdf*.

[178] National Association of Regulatory Utility Commissioners. (January 2020). Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices. *https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45*.

[179] U.S. Energy Information Administration (EIA), Electric Power Annual, table 3.1.A. November 2022. *https://www.eia.gov/electricity/annual/*.

[180] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emission Sources and Sinks. February 2023. *https://www.epa.gov/system/files/documents/2023-02/US-GHG-Inventory-2023-Main-Text.pdf*.

[181] U.S. Energy Information Administration (EIA). Today in Energy. Solar and battery storage to make up 81 percent of new U.S. electric-generating capacity in 2024. February 2024. *https://www.eia.gov/todayinenergy/detail.php?id=61424*.

1. Regulation of Emissions From New Sources

Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for ''new sources'' in the source category. These standards are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to the sources subject to them.

Under CAA section 111(a)(1), a ''standard of performance'' is defined, in the singular, as ''a standard for emissions of air pollutants'' that is determined in a specified manner, as noted in this section, below.

Under CAA section 111(a)(2), a ''new source'' is defined, in the singular, as ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section, which will be applicable to such source.'' Under CAA section 111(a)(3), a ''stationary source'' is defined as ''any building, structure, facility, or installation which emits or may emit any air pollutant.'' Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. While this provision treats modified sources as new sources, EPA regulations also treat a source that undergoes ''reconstruction'' as a new source. Under the provisions in 40 CFR 60.15, ''reconstruction'' means the replacement of components of an existing facility such that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect ''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 impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The term ''standard of performance'' in CAA 111(a)(1) makes clear that the EPA is to determine both the ''best system of emission reduction . . . adequately demonstrated'' (BSER) for the regulated sources in the source category and the ''degree of emission limitation achievable through the application of the [BSER].'' *West Virginia* v. *EPA*, 597 U.S. 697, 709 (2022). To determine the BSER, the EPA first identifies the ''system[s] of emission reduction'' that are ''adequately demonstrated,'' and then determines the ''best'' of those systems, ''taking into account'' factors including ''cost,'' ''nonair quality health and environmental impact,'' and ''energy requirements.'' The EPA then derives from that system an ''achievable'' ''degree of emission limitation.'' The EPA must then, under CAA section 111(b)(1)(B), promulgate ''standard[s] for emissions''—the NSPS—that reflect that level of stringency.

2. Regulation of Emissions From Existing Sources

When the EPA establishes a standard for emissions of an air pollutant from new sources within a category, it must also, under CAA section 111(d), regulate emissions of that pollutant from *existing* sources within the same category, unless the pollutant is regulated under the National Ambient Air Quality Standards (NAAQS) program, under CAA sections 108–110, or the National Emission Standards for Hazardous Air Pollutants (NESHAP) program, under CAA section 112. See CAA section 111(d)(1)(A)(i) and (ii); *West Virginia*, 597 U.S. at 710.

CAA section 111(d) establishes a framework of ''cooperative federalism for the regulation of existing sources.'' *American Lung Ass'n*, 985 F.3d at 931. CAA sections 111(d)(1)(A)–(B) require ''[t]he Administrator . . . to prescribe regulations'' that require ''[e]ach state . . . to submit to [EPA] a plan . . . which establishes standards of performance for any existing stationary source for'' the air pollutant at issue, and which ''provides for the implementation and enforcement of such standards of performance.'' CAA section 111(a)(6) defines an ''existing source'' as ''any stationary source other than a new source.''

To meet these requirements, the EPA promulgates ''emission guidelines'' that identify the BSER and the degree of emission limitation achievable through the application of the BSER. Each state must then establish standards of performance for its sources that reflect that level of stringency. However, the states need not compel regulated sources to adopt the particular components of the BSER itself. The EPA's emission guidelines must also permit a state, ''in applying a standard of performance to any particular source,'' to ''take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' 42 U.S.C. 7411(d)(1). Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the source, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the Act. CAA section 111(d)(2)(B). If a state elects not to submit a plan or submits a plan that the EPA does not find ''satisfactory,'' the EPA must promulgate a plan that establishes Federal standards of performance for the state's existing sources. CAA section 111(d)(2)(A).

3. EPA Review of Requirements

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years, review and, if appropriate, revise'' new source performance standards. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. *Id.* When conducting a review of an NSPS, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category. CAA section 111 does not by its terms require the EPA to review emission guidelines for existing sources, but the EPA retains the authority to do so. See 81 FR 59277 (August 29, 2016) (explaining legal authority to review emission guidelines for municipal solid waste landfills).

B. History of EPA Regulation of Greenhouse Gases From Electricity Generating Units Under CAA Section 111 and Caselaw

The EPA has listed more than 60 stationary source categories under CAA section 111(b)(1)(A). See 40 CFR part 60, subparts Cb–OOOO. In 1971, the EPA listed fossil fuel-fired EGUs (which includes natural gas, petroleum, and coal) that use steam-generating boilers in a category under CAA section 111(b)(1)(A). See 36 FR 5931 (March 31, 1971) (listing ''fossil fuel-fired steam generators of more than 250 million Btu per hour heat input''). In 1977, the EPA listed fossil fuel-fired combustion turbines, which can be used in EGUs, in a category under CAA section 111(b)(1)(A). See 42 FR 53657 (October 3, 1977) (listing ''stationary gas turbines'').

Beginning in 2007, several decisions by the U.S. Supreme Court and the D.C. Circuit have made clear that under CAA section 111, the EPA has authority to regulate GHG emissions from listed source categories. The U.S. Supreme Court ruled in *Massachusetts* v. *EPA* that GHGs [182] meet the definition of ''air pollutant'' in the CAA,[183] and subsequently premised its decision in *AEP* v. *Connecticut* [184]—that the CAA displaced any Federal common law right to compel reductions in CO_2 emissions from fossil fuel-fired power plants—on its view that CAA section 111 applies to GHG emissions. The D.C. Circuit confirmed in *American Lung Ass'n* v. *EPA,* 985 F.3d 914, 977 (D.C. Cir. 2021), discussed in section V.B.5, that the EPA is authorized to promulgate requirements under CAA section 111 for GHG from the fossil fuel-fired EGU source category notwithstanding that the source category is regulated under CAA section 112. As discussed in section V.B.6, the U.S. Supreme Court did not accept certiorari on the question whether the EPA could regulate GHGs from fossil-fuel fired EGUs under CAA section 111(d) when other pollutants from fossil-fuel fired EGUs are regulated under CAA section 112 in *West Virginia* v. *EPA,* 597 U.S. 697 (2022), and so the D.C. Circuit's holding on this issue remains good law.

In 2015, the EPA promulgated two rules that addressed CO_2 emissions from fossil fuel-fired EGUs. The first promulgated standards of performance for new fossil fuel-fired EGUs. ''Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule,'' (80 FR 64510; October 23, 2015) (2015 NSPS). The second promulgated emission guidelines for existing sources. ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule,'' (80 FR 64662; October 23, 2015) (Clean Power Plan, or CPP).

1. 2015 NSPS

In 2015, the EPA promulgated an NSPS to limit emissions of GHGs, manifested as CO_2, from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units, *i.e.,* utility boilers and IGCC EGUs, and newly constructed and reconstructed stationary combustion turbine EGUs. These final standards are codified in 40 CFR part 60, subpart TTTT. In promulgating the NSPS for newly constructed fossil fuel-fired steam generating units, the EPA determined the BSER to be a new, highly efficient, supercritical pulverized coal (SCPC) EGU that implements post-combustion partial CCS technology. The EPA concluded that CCS was adequately demonstrated (including being technically feasible) and widely available and could be implemented at reasonable cost. The EPA identified natural gas co-firing and IGCC technology (either with natural gas co-firing or implementing partial CCS) as alternative methods of compliance.

The 2015 NSPS included standards of performance for steam generating units that undergo a ''reconstruction'' as well as units that implement ''large modifications,'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent). The 2015 NSPS did not establish standards of performance for steam generating units that undertake ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent), due to the limited information available to inform the analysis of a BSER and corresponding standard of performance.

The 2015 NSPS also finalized standards of performance for newly constructed and reconstructed stationary combustion turbine EGUs. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the EPA finalized a standard based on efficient NGCC technology as the BSER. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines and for both base load and non-base load multi-fuel-fired stationary combustion turbines, the EPA finalized a heat input-based standard based on the use of lower-emitting fuels (referred to as clean fuels in the 2015 NSPS). The EPA did not promulgate final standards of performance for modified stationary combustion turbines due to lack of information. The 2015 NSPS remains in effect today.

The EPA received six petitions for reconsideration of the 2015 NSPS. On May 6, 2016 (81 FR 27442), the EPA denied five of the petitions on the basis that they did not satisfy the statutory conditions for reconsideration under CAA section 307(d)(7)(B) and deferred action on one petition that raised the issue of the treatment of biomass. Apart from these petitions, the EPA proposed to revise the 2015 NSPS in 2018, as discussed in section V.B.2.

Multiple parties also filed petitions for judicial review of the 2015 NSPS in the D.C. Circuit. These cases have been briefed and, on the EPA's motion, are being held in abeyance pending EPA action concerning the 2018 proposal to revise the 2015 NSPS.

In the 2015 NSPS, the EPA noted that it was authorized to regulate GHGs from the fossil fuel-fired EGU source categories because it had listed those source categories under CAA section 111(b)(1)(A). The EPA added that CAA section 111 did not require it to make a determination that GHGs from EGUs contribute significantly to dangerous air pollution (a pollutant-specific significant contribution finding), but in the alternative, the EPA did make that finding. It explained that ''[greenhouse gas] air pollution may reasonably be anticipated to endanger public health or welfare,'' 80 FR 64530 (October 23, 2015) and emphasized that power plants are ''by far the largest emitters'' of greenhouse gases among stationary sources in the U.S. *Id.* at 64522. In *American Lung Ass'n* v. *EPA,* 985 F.3d 977 (D.C. Cir. 2021), the court held that even if the EPA were required to determine that CO_2 from fossil fuel-fired EGUs contributes significantly to dangerous air pollution—and the court emphasized that it was not deciding that the EPA was required to make such a pollutant-specific determination—the determination in the alternative that the EPA made in the 2015 NSPS was not arbitrary and capricious and, accordingly, the EPA had a sufficient basis to regulate greenhouse gases from EGUs under CAA section 111(d) in the ACE Rule. This aspect of the decision remains good law. The EPA is not reopening and did not solicit comment on any of those determinations in the 2015 NSPS concerning its rational basis to regulate GHG emissions from EGUs or its alternative finding that GHG emissions from EGUs contribute significantly to dangerous air pollution.

2. 2018 NSPS Proposal To Revise the 2015 NSPS

In 2018, the EPA proposed to revise the NSPS for new, modified, and reconstructed fossil fuel-fired steam generating units and IGCC units, in the *Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Proposed Rule* (83 FR 65424;

[182] The EPA's 2009 endangerment finding defines the air pollution which may endanger public health and welfare as the well-mixed aggregate group of the following gases: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

[183] 549 U.S. 497, 520 (2007).

[184] 131 S. Ct. 2527, 2537–38 (2011).

December 20, 2018) (2018 NSPS Proposal). The EPA proposed to revise the NSPS for newly constructed units, based on a revised BSER of a highly efficient SCPC, without partial CCS. The EPA also proposed to revise the NSPS for modified and reconstructed units. As discussed in IX.A, in the present action, the EPA is withdrawing this proposed rule.[185]

3. Clean Power Plan

With the promulgation of the 2015 NSPS, the EPA also incurred a statutory obligation under CAA section 111(d) to issue emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs and stationary combustion turbine EGUs, which the EPA initially fulfilled with the promulgation of the CPP. See 80 FR 64662 (October 23, 2015). The EPA first determined that the BSER included three types of measures: (1) improving heat rate (*i.e.*, the amount of fuel that must be burned to generate a unit of electricity) at coal-fired steam plants; (2) substituting increased generation from lower-emitting NGCC plants for generation from higher-emitting steam plants (which are primarily coal-fired); and (3) substituting increased generation from new renewable energy sources for generation from fossil fuel-fired steam plants and combustion turbines. See 80 FR 64667 (October 23, 2015). The latter two measures are known as ''generation shifting'' because they involve shifting electricity generation from higher-emitting sources to lower-emitting ones. See 80 FR 64728–29 (October 23, 2015).

The EPA based this BSER determination on a technical record that evaluated generation shifting, including its cost-effectiveness, against the relevant statutory criteria for BSER and on a legal interpretation that the term ''system'' in CAA section 111(a)(1) is sufficiently broad to encompass shifting of generation from higher-emitting to lower-emitting sources. See 80 FR 64720 (October 23, 2015). The EPA then determined the ''degree of emission limitation achievable through the application of the [BSER],'' CAA section 111(a)(1), expressed as emission performance rates. See 80 FR 64667 (October 23, 2015). The EPA explained that a state would ''have to ensure, through its plan, that the emission standards it establishes for its sources individually, in the aggregate, or in combination with other measures undertaken by the state, represent the equivalent of'' those performance rates (80 FR 64667; October 23, 2015). Neither states nor sources were required to apply the specific measures identified in the BSER (80 FR 64667; October 23, 2015), and states could include trading or averaging programs in their state plans for compliance. See 80 FR 64840 (October 23, 2015).

Numerous states and private parties petitioned for review of the CPP before the D.C. Circuit. On February 9, 2016, the U.S. Supreme Court stayed the rule pending review, *West Virginia* v. *EPA*, 577 U.S. 1126 (2016). The D.C. Circuit held the litigation in abeyance, and ultimately dismissed it at the petitioners' request. *American Lung Ass'n*, 985 F.3d at 937.

4. The CPP Repeal and ACE Rule

In 2019, the EPA repealed the CPP and replaced it with the ACE Rule. In contrast to its interpretation of CAA section 111 in the CPP, in the ACE Rule the EPA determined that the statutory ''text and reasonable inferences from it'' make ''clear'' that a ''system'' of emission reduction under CAA section 111(a)(1) ''is limited to measures that can be applied to and at the level of the individual source,'' (84 FR 32529; July 8, 2019); that is, the system must be limited to control measures that could be applied at and to each source to reduce emissions at each source. See 84 FR 32523–24 (July 8, 2019). Specifically, the ACE Rule argued that the requirements in CAA sections 111(d)(1), (a)(3), and (a)(6), that each state establish a standard of performance ''for'' ''any existing source,'' defined, in general, as any ''building . . . [or] facility,'' and the requirement in CAA section 111(a)(1) that the degree of emission limitation must be ''achievable'' through the ''application'' of the BSER, by their terms, impose this limitation. The EPA concluded that generation shifting is not such a control measure. See 84 FR 32546 (July 8, 2019). Based on its view that the CPP was a ''major rule,'' the EPA further determined that, absent ''a clear statement from Congress,'' the term '' 'system of emission reduction' '' should not be read to encompass ''generation-shifting measures.'' See 84 FR 32529 (July 8, 2019). The EPA acknowledged, however, that ''[m]arket-based forces ha[d] already led to significant generation shifting in the power sector,'' (84 FR 32532; July 8, 2019), and that there was ''likely to be no difference between a world where the CPP is implemented and one where it is not.'' See 84 FR 32561 (July 8, 2019); the Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, 2–1 to 2–5.[186]

In addition, the EPA promulgated in the ACE Rule a new set of emission guidelines for existing coal-fired steam-generating EGUs. See 84 FR 32532 (July 8, 2019). In light of ''the legal interpretation adopted in the repeal of the CPP,'' (84 FR 32532; July 8, 2019)—which ''limit[ed] 'standards of performance' to systems that can be applied at and to a stationary source,'' (84 FR 32534; July 8, 2019)—the EPA found the BSER to be heat rate improvements alone. See 84 FR 32535 (July 8, 2019). The EPA listed various technologies that could improve heat rate (84 FR 32536; July 8, 2019), and identified the ''degree of emission limitation achievable'' by ''providing ranges of expected [emission] reductions associated with each of the technologies.'' See 84 FR 32537–38 (July 8, 2019).

5. D.C. Circuit Decision in American Lung Association v. EPA Concerning the CPP Repeal and ACE Rule

Numerous states and private parties petitioned for review of the CPP Repeal and ACE Rule. In 2021, the D.C. Circuit vacated the ACE Rule, including the CPP Repeal. *American Lung Ass'n* v. *EPA*, 985 F.3d 914 (D.C. Cir. 2021). The court held, among other things, that CAA section 111(d) does not limit the EPA, in determining the BSER, to measures applied at and to an individual source. The court noted that ''the sole ground on which the EPA defends its abandonment of the [CPP] in favor of the ACE Rule is that the text of [CAA section 111] is clear and unambiguous in constraining the EPA to use only improvements at and to existing sources in its [BSER].'' 985 F.3d at 944. The court found ''nothing in the text, structure, history, or purpose of [CAA section 111] that compels the reading the EPA adopted.'' 985 F.3d at 957. The court likewise rejected the

185 In the 2018 NSPS Proposal, the EPA solicited comment on whether it is required to make a determination that GHGs from a source category contribute significantly to dangerous air pollution as a predicate to promulgating a NSPS for GHG emissions from that source category for the first time. 83 FR 65432 (December 20, 2018). The EPA subsequently issued a final rule that provided that it would not regulate GHGs under CAA section 111 from a source category unless the GHGs from the category exceed 3 percent of total U.S. GHG emissions, on grounds that GHGs emitted in a lesser amount do not contribute significantly to dangerous air pollution. 86 FR 2652 (January 13, 2021). Shortly afterwards, the D.C. Circuit granted an unopposed motion by the EPA for voluntary vacatur and remand of the final rule. *California* v. *EPA*, No. 21–1035, doc. 1893155 (D.C. Cir. April 5, 2021).

186 *https://www.epa.gov/sites/default/files/2019-06/documents/utilities_ria_final_cpp_repeal_and_ace_2019-06.pdf.*

view that the CPP's use of generation-shifting implicated a "major question" requiring unambiguous authorization by Congress. 985 F.3d at 958–68.

The D.C. Circuit concluded that, because the EPA had relied on an "erroneous legal premise," both the CPP Repeal Rule and the ACE Rule should be vacated. 985 F.3d at 995. The court did not decide, however, "whether the approach of the ACE Rule is a permissible reading of the statute as a matter of agency discretion," 985 F.3d at 944, and instead "remanded to the EPA so that the Agency may 'consider the question afresh,' " 985 F.3d at 995 (citations omitted).

The court also rejected the arguments that the EPA cannot regulate CO_2 emissions from coal-fired power plants under CAA section 111(d) at all because it had already regulated mercury emissions from coal-fired power plants under CAA section 112. 985 F.3d at 988. In addition, the court held that that the 2015 NSPS included a valid determination that greenhouse gases from the EGU source category contributed significantly to dangerous air pollution, which provided a sufficient basis for a CAA section 111(d) rule regulating greenhouse gases from existing fossil fuel-fired EGUs. *Id.* at 977.

Because the D.C. Circuit vacated the ACE Rule on the grounds noted above, it did not address the other challenges to the ACE Rule, including the arguments by Petitioners that the heat rate improvement BSER was inadequate because of the limited number of reductions it achieved and because the ACE Rule failed to include an appropriately specific degree of emission limitation.

Upon a motion from the EPA, the D.C. Circuit agreed to stay its mandate with respect to vacatur of the CPP Repeal, *American Lung Assn* v. *EPA,* No. 19–1140, Order (February 22, 2021), so that the CPP remained repealed. Therefore, following the D.C. Circuit's decision, no EPA rule under CAA section 111 to reduce GHGs from existing fossil fuel-fired EGUs remained in place.

6. U.S. Supreme Court Decision in West Virginia v. EPA Concerning the CPP

The Supreme Court granted petitions for certiorari from the D.C. Circuit's *American Lung Association* decision, limited to the question of whether CAA section 111 authorized the EPA to determine that "generation shifting" was the best system of emission reduction for fossil-fuel fired EGUs. The Supreme Court did not grant certiorari on the question of whether the EPA was authorized to regulate GHG emissions from fossil-fuel fired power plants under CAA section 111, when fossil-fuel fired power plants are regulated for other pollutants under CAA section 112. In 2022, the U.S. Supreme Court reversed the D.C. Circuit's vacatur of the ACE Rule's embedded repeal of the CPP. *West Virginia* v. *EPA,* 597 U.S. 697 (2022). The Supreme Court stated that CAA section 111 authorizes the EPA to determine the BSER and the degree of emission limitation that state plans must achieve. *Id.* at 2601–02. The Supreme Court concluded, however, that the CPP's BSER of "generation-shifting" raised a "major question," and was not clearly authorized by section 111. The Court characterized the generation-shifting BSER as "restructuring the Nation's overall mix of electricity generation," and stated that the EPA's claim that CAA section 111 authorized it to promulgate generation shifting as the BSER was "not only unprecedented; it also effected a fundamental revision of the statute, changing it from one sort of scheme of regulation into an entirely different kind." *Id.* at 2612 (internal quotation marks, brackets, and citation omitted). The Court explained that the EPA, in prior rules under CAA section 111, had set emissions limits based on "measures that would reduce pollution by causing the regulated source to operate more cleanly." *Id.* at 2610. The Court noted with approval those "more traditional air pollution control measures," and gave as examples "fuel-switching" and "add-on controls," which, the Court observed, the EPA had considered in the CPP. *Id.* at 2611 (internal quotations marks and citation omitted). In contrast, the Court continued, generation shifting was "unprecedented" because "[r]ather than focus on improving the performance of individual sources, it would improve the overall power system by lowering the carbon intensity of power generation. And it would do that by forcing a shift throughout the power grid from one type of energy source to another." *Id.* at 2611–12 (internal quotation marks, emphasis, and citation omitted).

The Court recognized that a rule based on traditional measures "may end up causing an incidental loss of coal's market share," but emphasized that the CPP was "obvious[ly] differen[t]" because, with its generation-shifting BSER, it "simply announc[ed] what the market share of coal, natural gas, wind, and solar must be, and then require[ed] plants to reduce operations or subsidize their competitors to get there." *Id.* at 2613 n.4. The Court also emphasized "the magnitude and consequence" of the CPP. *Id.* at 2616. It noted "the magnitude of this unprecedented power over American industry," *id.* at 2612 (internal quotation marks and citation omitted), and added that the EPA's adoption of generation shifting "represent[ed] a transformative expansion in its regulatory authority." *Id.* at 2610 (internal quotation marks and citation omitted). The Court also viewed the CPP as promulgating "a program that . . . Congress had considered and rejected multiple times." *Id.* at 2614 (internal quotation marks and citation omitted). For these and related reasons, the Court viewed the CPP as raising a major question, and therefore, requiring "clear congressional authorization" as a basis. *Id.* (internal quotation marks and citation omitted).

The Court declined to address the D.C. Circuit's conclusion that the text of CAA section 111 did not limit the type of "system" the EPA could consider as the BSER to measures applied at and to an individual source. *See id.* at 2615. Nor did the Court address the scope of the states' compliance flexibilities.

7. D.C. Circuit Order Reinstating the ACE Rule

On October 27, 2022, the D.C. Circuit responded to the U.S. Supreme Court's reversal by recalling its mandate for the vacatur of the ACE Rule. *American Lung Ass'n* v. *EPA,* No. 19–1140, Order (October 27, 2022). Accordingly, at that time, the ACE Rule came back into effect. The court also revised its judgment to deny petitions for review challenging the CPP Repeal Rule, consistent with the judgment in *West Virginia,* so that the CPP remains repealed. The court took further action denying several of the petitions for review unaffected by the Supreme Court's decision in *West Virginia,* which means that certain parts of its 2021 decision in *American Lung Association* remain in effect. These parts include the holding that the EPA's prior regulation of mercury emissions from coal-fired electric power plants under CAA section 112 does not preclude the Agency from regulating CO_2 from coal-fired electric power plants under CAA section 111, and the holding, discussed above, that the 2015 NSPS included a valid significant contribution determination and therefore provided a sufficient basis for a CAA section 111(d) rule regulating greenhouse gases from existing fossil fuel-fired EGUs. The court's holding to invalidate amendments to the implementing regulations applicable to emission guidelines under CAA section 111(d) that extended the preexisting schedules for state and Federal actions and sources' compliance, also remains in force. Based on the EPA's stated intention to replace the ACE Rule, the court stayed further proceedings with respect to the ACE Rule, including the various challenges that its BSER was flawed because it did not achieve sufficient emission reductions and failed to specify an appropriately specific degree of emission limitation.

C. Detailed Discussion of CAA Section 111 Requirements

This section discusses in more detail the key requirements of CAA section 111 for both new and existing sources that are relevant for these rulemakings.

1. Approach to the Source Category and Subcategorizing

CAA section 111 requires the EPA first to list stationary source categories that cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare and then to regulate new sources within each such source category. CAA section 111(b)(2) grants the EPA discretion whether to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards," which we refer to as "subcategorizing." Whether and how to subcategorize is a decision for which the EPA is entitled to a "high degree of deference" because it entails "scientific judgment." *Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

Although CAA section 111(d)(1) does not explicitly address subcategorization, since its first regulations implementing the CAA, the EPA has interpreted it to authorize the Agency to exercise discretion as to whether and, if so, how to subcategorize, for the following reasons. CAA section 111(d)(1) grants the EPA authority to "prescribe regulations which shall establish a procedure . . . under which each State shall submit to the Administrator a plan [with standards of performance for existing sources.]" The EPA promulgates emission guidelines under this provision directing the states to regulate existing sources. The Supreme Court has recognized that, under CAA section 111(d), the "Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, 'the best system of emission reduction . . . that has been adequately demonstrated for [existing covered] facilities.' *West Virginia*, 597 U.S. at 710 (citations omitted).

The EPA's authority to determine the BSER includes the authority to create subcategories that tailor the BSER for differently situated sets of sources. Again, for new sources, CAA section 111(b)(2) confers authority for the EPA to "distinguish among classes, types, and sizes within categories." Though CAA section 111(d) does not speak specifically to the creation of subcategories for a category of existing sources, the authority to identify the "best" system of emission reduction for existing sources includes the discretion to differentiate between differently situated sources in the category, and group those sources into subcategories in appropriate circumstances. The size, type, class, and other characteristics can make different emission controls more appropriate for different sources. A system of emission reduction that is "best" for some sources may not be "best" for others with different characteristics. For more than four decades, the EPA has interpreted CAA section 111(d) to confer authority on the Agency to create subcategories. The EPA's implementing regulations under CAA section 111(d), promulgated in 1975, 40 FR 53340 (November 17, 1975), provide that the Administrator will specify different emission guidelines or compliance times or both "for different sizes, types, and classes of designated facilities when [based on] costs of control, physical limitations, geographical location, or [based on] similar factors."[187] This regulation governs the EPA's general authority to subcategorize under CAA section 111(d), and the EPA is not reopening that issue here. At the time of promulgation, the EPA explained that subcategorization allows the EPA to take into account "differences in sizes and types of facilities and similar considerations, including differences in control costs that may be involved for sources located in different parts of the country" so that the "EPA's emission guidelines will in effect be tailored to what is reasonably achievable by particular classes of existing sources. . . ." *Id.* at 53343. The EPA's authority to "distinguish among classes, types, and sizes within categories," as provided under CAA section 111(b)(2), generally allows the Agency to place types of sources into subcategories. This is consistent with the commonly understood meaning of the term "type" in CAA section 111(b)(2): "a particular kind, class, or group," or "qualities common to a number of individuals that distinguish them as an identifiable class." See *https://www.merriam-webster.com/dictionary/type*.

[187] 40 CFR 60.22(b)(5), 60.22a(b)(5). Because the definition of subcategories depends on characteristics relevant to the BSER, and because those characteristics can differ as between new and existing sources, the EPA may establish different subcategories as between new and existing sources.

The EPA has developed subcategories in many rulemakings under CAA section 111 since the 1970s. These rulemakings have included subcategories on the basis of the size of the sources, see 40 CFR 60.40b(b)(1)–(2) (subcategorizing certain coal-fired steam generating units on the basis of heat input capacity); the types of fuel combusted, *see Sierra Club*, v. *EPA*, 657 F.2d 298, 318–19 (D.C. Cir. 1981) (upholding a rulemaking that established different NSPS "for utility plants that burn coal of varying sulfur content"), 2015 NSPS, 80 FR 64510, 64602 (table 15) (October 23, 2015) (subdividing new combustion turbines on the basis of type of fuel combusted); the types of equipment used to produce products, see 81 FR 35824 (June 3, 2016) (promulgating separate NSPS for many types of oil and gas sources, such as centrifugal compressors, pneumatic controllers, and well sites); types of manufacturing processes used to produce product, see 42 FR 12022 (March 1, 1977) (announcing availability of final guideline document for control of atmospheric fluoride emissions from existing phosphate fertilizer plants) and "Final Guideline Document: Control of Fluoride Emissions From Existing Phosphate Fertilizer Plants," EPA–450/2–77–005 1–7 to 1–9, including table 1–2 (applying different control requirements for different manufacturing operations for phosphate fertilizer); levels of utilization of the sources, see 2015 NSPS, 80 FR 64510, 64602 (table 15) (October 23, 2015) (dividing new natural gas-fired combustion turbines into the subcategories of base load and non-base load); the activity level of the sources, see 81 FR 59276, 59278–79 (August 29, 2016) (dividing municipal solid waste landfills into the subcategories of active and closed landfills); and geographic location of the sources, see 71 FR 38482 (July 6, 2006) (SO_2 NSPS for stationary combustion turbines subcategorizing turbines on the basis of whether they are located in, for example, a continental area, a non-continental area, the part of Alaska north of the Arctic Circle, and the rest of Alaska). Thus, the EPA has subcategorized many times in rulemaking under CAA sections 111(b) and 111(d) and based on a wide variety of physical, locational, and operational characteristics.

Regardless of whether the EPA subcategorizes within a source category for purposes of determining the BSER and the degree of emission limitation achievable, a state retains certain flexibility in assigning standards of performance to its affected EGUs. The statutory framework for CAA section 111(d) emission guidelines, and the flexibilities available to states within that framework, are discussed below.

2. Key Elements of Determining a Standard of Performance

Congress first included the definition of ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. The current text of CAA section 111(a)(1) reads: ''The term 'standard of performance' means a standard for emission 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 impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The D.C. Circuit has reviewed CAA section 111 rulemakings on numerous occasions since 1973,[188] and has developed a body of caselaw that interprets the term ''standard of performance,'' as discussed throughout this preamble.

The basis for standards of performance, whether promulgated by the EPA under CAA section 111(b) or established by the states under CAA section 111(d), is that the EPA determines the ''degree of emission limitation'' that is ''achievable'' by the sources by application of a ''system of emission reduction'' that the EPA determines is ''adequately demonstrated,'' ''taking into account'' the factors of ''cost . . . and any nonair quality health and environmental impact and energy requirements,'' and that the EPA determines to be the ''best.'' The D.C. Circuit has stated that in determining the ''best'' system, the EPA must also take into account ''the amount of air pollution''[189] reduced and the role of ''technological innovation.''[190] The D.C. Circuit has also stated that to determine the ''best'' system, the EPA may weigh the various factors identified in the statute and caselaw against each other, and has emphasized that the EPA has discretion in weighing the factors.[191] [192]

The EPA's overall approach to determining the BSER and degree of emission limitation achievable, which incorporates the various elements, is as follows: The EPA identifies ''system[s] of emission reduction'' that have been ''adequately demonstrated'' for a particular source category and determines the ''best'' of these systems after evaluating the amount of emission reductions, costs, any non-air health and environmental impacts, and energy requirements. As discussed below, for each of numerous subcategories, the EPA followed this approach to determine the BSER on the basis that the identified costs are reasonable and that the BSER is rational in light of the statutory factors, including the amount of emission reductions, that the EPA examined in its BSER analysis, consistent with governing precedent.

After determining the BSER, the EPA determines an achievable emission limit based on application of the BSER.[193] For a CAA section 111(b) rule, the EPA determines the standard of performance that reflects the achievable emission limit. For a CAA section 111(d) rule, the states have the obligation of establishing standards of performance for the affected sources that reflect the degree of emission limitation that the EPA has determined. As discussed below, the EPA is finalizing these determinations in association with each of the BSER determinations.

The remainder of this subsection discusses each element in our general analytical approach.

a. System of Emission Reduction

The CAA does not define the phrase ''system of emission reduction.'' In *West Virginia* v. *EPA*, the Supreme Court recognized that historically, the EPA had looked to ''measures that improve the pollution performance of individual sources and followed a ''technology-based approach'' in identifying systems of emission reduction. In particular, the Court identified ''the sort of 'systems of emission reduction' [the EPA] had always before selected,'' which included '' 'efficiency improvements, fuel-switching,' and 'add-on controls'.'' 597 U.S. at 727 (quoting the Clean Power Plan).[194] Section 111 itself recognizes that such systems may include off-site activities that may reduce a source's pollution contribution, identifying ''precombustion cleaning or treatment of fuels'' as a ''system'' of ''emission reduction.'' 42 U.S.C. 7411(a)(7)(B). A ''system of emission reduction'' thus, at a minimum, includes measures that an individual source applies that improve the emissions performance of that source. Measures are fairly characterized as improving the pollution performance of a source where they reduce the individual source's overall contribution to pollution.

In *West Virginia*, the Supreme Court did not define the term ''system of emissions reduction,'' and so did not rule on whether ''system of emission reduction'' is limited to those measures that the EPA has historically relied upon. It did go on to apply the major questions doctrine to hold that the term ''system'' does not provide the requisite clear authorization to support the Clean Power Plan's BSER, which the Court described as ''carbon emissions caps based on a generation shifting approach.'' *Id.* at 2614. While the Court did not define the outer bounds of the meaning of ''system,'' systems of emissions reduction like fuel switching, add-on controls, and efficiency improvements fall comfortably within the scope of prior practice as recognized by the Supreme Court.

b. ''Adequately Demonstrated''

Under CAA section 111(a)(1), an essential, although not sufficient, condition for a ''system of emission

[188] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011); *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021), *rev'd in part, West Virginia* v. *EPA,* 597 U.S. 697 (2022). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

[189] *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

[190] *See Sierra Club* v. *Costle,* 657 F.2d at 347.

[191] *See Lignite Energy Council,* 198 F.3d at 933.

[192] CAA section 111(a)(1), by its terms states that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination. In addition, the D.C. Circuit's caselaw makes clear that the EPA may consider these same factors when it determines which adequately demonstrated system of emission reduction is the ''best.'' *See Sierra Club* v. *Costle,* 657 F.2d at 330 (recognizing that CAA section 111 gives the EPA authority ''when determining the best technological system to weigh cost, energy, and environmental impacts'').

[193] See, *e.g.,* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews (77 FR 49494; August 16, 2012) (describing the three-step analysis in setting a standard of performance).

[194] As noted in section V.B.4 of this preamble, the ACE Rule adopted the interpretation that CAA section 111(a)(1), by its plain language, limits ''system of emission reduction'' to those control measures that could be applied at and to each source to reduce emissions at each source. 84 FR 32523–24 (July 8, 2019). The EPA has subsequently rejected that interpretation as too narrow. *See Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d),* 88 FR 80535 (November 17, 2023).

reduction'' to serve as the basis for an ''achievable'' emission standard is that the Administrator must determine that the system is ''adequately demonstrated.'' The concepts of adequate demonstration and achievability are closely related: as the D.C. Circuit has stated, ''[i]t is the system which must be adequately demonstrated and the standard which must be achievable,'' [195] through application of the system. An achievable standard means a standard based on the EPA's record-based finding that sufficient evidence exists to reasonably determine that the affected sources in the source category can adopt a specific system of emission reduction to achieve the specified degree of emission limitation. As discussed below, consistent with Congress's use of the word ''demonstrated,'' the caselaw has approved the EPA's ''adequately demonstrated'' determinations concerning systems utilized at test sources or other individual sources operating at commercial scale. The case law also authorizes the EPA to set an emissions standard at levels more stringent than has regularly been achieved, based on the understanding that sources will be able to adopt specific technological improvements to the system in question that will enable them to achieve the lower standard. Importantly, and contrary to some comments received on the proposed rule, CAA section 111(a)(1) does *not* require that a system of emission reduction exist in widespread commercial use in order to satisfy the ''adequately demonstrated'' requirement.[196] Instead, CAA section 111(a)(1) authorizes the EPA to establish standards which encourage the deployment of more effective systems of emission reduction that have been adequately demonstrated but that are not yet in widespread use. This aligns with Congress's purpose in enacting the CAA, in particular its recognition that polluting sources were not widely adopting emission control technology on a voluntary basis and that Federal regulation was necessary to spur the development and deployment of those technologies.[197]

i. Plain Text, Statutory Context, and Legislative History of the ''Adequately Demonstrated'' Provision in CAA Section 111(a)(1)

Analysis of the plain text, statutory context, and legislative history of CAA section 111(a)(1) establishes two primary themes. First, Congress assigned the task of determining the appropriate BSER to the Administrator, based on a reasonable review of available evidence. Second, Congress authorized the EPA to set a standard, based on the evidence, that encourages broader adoption of an emissions-reducing technological approach that may not yet be in widespread use.

The plain text of CAA section 111(a)(1), and in particular the phrase ''the Administrator determines'' and the term ''adequately,'' confer discretion to the EPA in identifying the appropriate system. Rather than providing specific criteria for determining what constitutes appropriate evidence, Congress directed the Administrator to ''determine[ ]'' that the demonstration is ''adequate[ ].'' Courts have typically deferred to the EPA's scientific and technological judgments in making such determinations.[198] Further, use of the term ''adequate'' in provisions throughout the CAA highlights EPA flexibility and discretion in setting standards and in analyzing data that forms the basis for standard setting.

In setting NAAQS under CAA section 109, for example, the EPA is directed to determine, according to ''the judgment of the Administrator,'' an ''adequate margin of safety.'' [199] The D.C. Circuit has held that the use of the term ''adequate'' confers significant deference to the Administrator's scientific and technological judgment. In *Mississippi* v. *EPA*,[200] for example, the D.C. Circuit in 2013 upheld the EPA's choice to set the NAAQS for ozone below 0.08 ppm, and noted that any disagreements with the EPA's interpretations of the scientific evidence that underlay this decision ''must come from those who are qualified to evaluate the science, not [the court].'' [201] This *Mississippi* v. *EPA* precedent aligns with the general standard for judicial review of the EPA's understanding of the evidence under CAA section 307(d)(9)(A) (''arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law'').

The plain language of the phrase ''has been adequately demonstrated,'' in context, and in light of the legislative history, further strongly indicates that the system in question need not be in widespread use at the time the EPA's rule is published. To the contrary, CAA section 111(a)(1) authorizes technology forcing, in the sense that the EPA is authorized to promote a system which is not yet in widespread use; provided the technology is in existence and the EPA has adequate evidence to extrapolate.[202]

Some commenters argued that use of the phrase ''has been'' in ''has been adequately demonstrated'' means that the system must be in widespread commercial use at the time of rule promulgation. We disagree. Considering the plain text, the use of the past tense, ''*has been* adequately demonstrated'' indicates a requirement that the technology *currently* be demonstrated. However, ''demonstrated'' in common usage at the time of enactment meant to ''explain or make clear by using examples, experiments, *etc.*'' [203] As a general matter, and as this definition indicates, the term ''to demonstrate'' suggests the need for a test or study—as in, for example, a ''demonstration

[195] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (1973) (emphasis omitted).

[196] *See, e.g., Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973) (in which the D.C. Circuit upheld a CAA section 111 standard based on a system which had been extensively used in Europe but at the time of promulgation was only in use in the United States at one plant).

[197] In introducing the respective bills which ultimately became the 1970 Clean Air Act upon Conference Committee review, both the House and Senate emphasized the urgency of the matter at hand, the intended power of the new legislation, and in particular its technology-forcing nature. The first page of the House report declared that ''[t]he purpose of the legislation reported unanimously by [Committee was] to speed up, expand, and intensify the war against air pollution in the United States . . .'' H.R. Rep. No. 17255 at 1 (1970). It was clear, stated the House report, that until that point ''the strategies which [the United States had] pursued in the war against air pollution [had] been inadequate in several important respects, and the methods employed in implementing those strategies often [had] been slow and less effective than they might have been.'' *Id.* The Senate report agreed, stating that their bill would ''provide a much more intensive and comprehensive attack on air pollution,'' 1 S. 4358 at 4 (1970), including, crucially, by increased federal involvement. *See id.*

[198] The D.C. Circuit stated in *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 786 (D.C. Cir. 1976) ''The standard of review of actions of the Administrator in setting standards of performance is an appropriately deferential one, and we are to affirm the action of the Administrator unless it is ''arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law,'' 5 U.S.C. 706(2)(A) (1970). Since this is one of those ''highly technical areas, where our understanding of the import of the evidence is attenuated, our readiness to review evidentiary support for decisions must be correspondingly restrained.'' *Ethyl Corporation* v. *EPA,* 96 S. Ct. 2663 (1976). ''Our 'expertise' is not in setting standards for emission control, but in determining if the standards as set are the result of reasoned decision-making.'' *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 434 (D.C. Cir. 1973)) (cleaned up).''

[199] 42 U.S.C. 7409(b)(1).

[200] 744 F.3d 1334 (D.C. Cir. 2013).

[201] *Id.*

[202] While not relevant here, because CCS is already in existence, the text, case law, and legislative history make a compelling case that EPA is authorized to go farther than this, and may make a projection regarding the way in which a particular system will develop to allow for greater emissions reductions in the future. *See* 80 FR 64556–58 (discussion of ''adequately demonstrated'' in 2015 NSPS).

[203] Webster's New World Dictionary: Second College Edition (David B. Guralnik, ed., 1972).

project'' or ''demonstration plant''—that is, examples of technological feasibility.

The statutory context is also useful in establishing that where Congress wanted to specify the availability of the control system, it did so. The only other use of the exact term ''adequately demonstrated'' occurs in CAA section 119, which establishes that, in order for the EPA to require a particular ''means of emission limitation'' for smelters, the Agency must establish that such means ''has been adequately demonstrated to be reasonably available. . . .'' [204] The lack of the phrase ''reasonably available'' in CAA section 111(a)(1) is notable, and suggests that a system may be ''adequately demonstrated'' under CAA section 111 even if it is not ''reasonably available'' for every single source.[205]

The term ''demonstration'' also appears in CAA section 103 in an instructive context. CAA section 103, which establishes a ''national research and development program for the prevention and control of air pollution'' directs that as part of this program, the EPA shall ''conduct, and promote the coordination and acceleration of, research, investigations, experiments, demonstrations, surveys, and studies relating to'' the issue of air pollution.[206] According to the canon of *noscitur a sociis*, associated words in a list bear on one another's meaning.[207] In CAA section 103, the word ''demonstrations'' appears alongside ''research,'' ''investigations,'' ''experiments,'' and ''studies''—all words suggesting the development of new and emerging technology. This supports interpreting CAA section 111(a)(1) to authorize the EPA to determine a system of emission reduction to be ''adequately demonstrated'' based on demonstration projects, testing, examples, or comparable evidence.

Finally, the legislative history of the CAA in general, and section 111 in particular, strongly supports the point that BSER technology need not be in widespread use at the time of rule enactment. The final language of CAA section 111(a)(1), requiring that systems of emission reduction be ''adequately demonstrated,'' was the result of compromise in the Conference Committee between the House and Senate bill language. The House bill would have required that the EPA give ''appropriate consideration to technological and economic feasibility'' when establishing standards.[208] The Senate bill would have required that standards ''reflect the greatest degree of emission control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.'' [209] Although the exact language of neither the House nor Senate bill was adopted in the final bill, both reports made clear their intent that CAA section 111 would be significantly technology-forcing. In particular, the Senate Report referred to ''available control technology''—a phrase that, as just noted, the Senate bill included—but clarified that the technology need not ''be in actual, routine use somewhere.'' [210] The House Report explained that EPA regulations would ''prevent and control such emissions to the fullest extent compatible with the available technology and economic feasibility as determined by [the EPA],'' and ''[i]n order to be considered 'available' the technology may not be one which constitutes a purely theoretical or experimental means of preventing or controlling air pollution.'' [211] This last statement implies that the House Report anticipated that the EPA's determination may be technology forcing. Nothing in the legislative history suggests that Congress intended that the technology already be in widespread commercial use.

ii. Caselaw

In a series of cases reviewing standards for new sources, the D.C. Circuit has held that an adequately demonstrated standard of performance may reflect the EPA's reasonable projection of what that particular system may be expected to achieve going forward, extrapolating from available data from pilot projects or individual commercial-scale sources. A standard may be considered achievable even if the system upon which the standard is based has not regularly achieved the standard in testing. See, *e.g.*, *Essex Chem. Corp.* v. *Ruckelshaus* [212] (upholding a standard of 4.0 lbs per ton based on a system whose average control rate was 4.6 lbs per ton, and which had achieved 4.0 lbs per ton on only three occasions and '''nearly equaled' [the standard] on the average of nineteen different readings.'') [213] The *Ruckelshaus* court concluded that the EPA's extrapolation from available data was ''the result of the exercise of reasoned discretion by the Administrator'' and therefore ''[could not] be upset by [the] court.'' [214] The court also emphasized that in order to be considered achievable, the standard set by the EPA need not be regularly or even specifically achieved at the time of rule promulgation. Instead, according to the court, ''[a]n 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 necessarily be routinely achieved within the industry prior to its adoption.'' [215]

Case law also establishes that the EPA may set a standard more stringent than has regularly been achieved based on its identification of specific available technological improvements to the system. See *Sierra Club* v. *Costle* [216] (upholding a 90 percent standard for SO_2 emissions from coal-fired steam generators despite the fact that not all plants had previously achieved this standard, based on the EPA's expectations for improved performance with specific technological fixes and the use of ''coal washing'' going forward).[217] Further, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different,

[204] The statutory text at CAA section 119 continues, ''as determined by the Administrator, taking into account the cost of compliance, nonair quality health and environmental impact, and energy consideration.'' 42 U.S.C. 7419(b)(3).

[205] It should also be noted that the section 119 language was added as part of the 1977 Clean Air Act amendments, while the section 111 language was established in 1970. Thus, Congress was aware of section 111's more permissive language when it added the ''reasonably available'' language to section 119.

[206] 42 U.S.C. 7403(a)(1).

[207] As the Supreme Court recently explained in *Dubin* v. *United States*, even words that might be indeterminate alone may be more easily interpreted in ''company,'' because per *noscitur a sociis* ''a word is known by the company it keeps.'' 599 U.S. 110, 244 (2023).

[208] H.R. Rep. No. 17255 at 921 (1970) (quoting CAA Sec. 112(a), as proposed).

[209] S. Rept. 4358 at 91 (quoting CAA Sec. 113(b)(2), as proposed).

[210] S. Rep. 4358 at 15–16 (1970). The Senate Report went on to say that the EPA should ''examine the degree of emission control that has been or can be achieved through the application of technology which is available or normally can be made available . . . at a cost and at a time which [the Agency] determines to be reasonable.'' *Id.* Again, this language rebuts any suggestion that a BSER technology must be in widespread use at the time of rule enactment—Congress assumed only that the technology would be ''available'' or even that it ''[could] be made available,'' not that it would be *already* broadly used.

[211] H.R. Rep. No. 17255 at 900.

[212] 486 F.2d 427 (D.C. Cir. 1973).

[213] *Id.* at 437.

[214] *Id.* at 437.

[215] *Id.* at 433–34 (D.C. Cir. 1973). *See also Sierra Club* v. *Costle*, 657 F.2d 298 (D.C. Cir. 1981), which supports the point that EPA may extrapolate from testing results, rather than relying on consistent performance, to identify an appropriate system and standard based on that system. In that case, EPA analyzed scrubber performance by considering performance during short-term testing periods. *See id.* at 377.

[216] 657 F.2d 298 (D.C. Cir. 1981).

[217] *Id.* at 365, 370–73; 365.

related, source. See *Lignite Energy Council* v. *EPA* [218] (holding it permissible to base a standard for industrial boilers on application of SCR based on extrapolated information about the application of SCR on utility boilers).[219] The *Lignite* court clarified that "where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture," but the "EPA 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." [220]

As a general matter, the case law is clear that at the time of Rule promulgation, the system which the EPA establishes as BSER need not be in widespread use. See, *e.g.*, *Ruckelshaus* [221] (upholding a standard based on a relatively new system which was in use at only one United States plant at the time of rule promulgation. Although the system was in use more extensively in Europe at the time of rule promulgation, the EPA based its analysis on test results from the lone U.S. plant only.) [222] This makes good sense, because, as discussed above, CAA section 111(a)(1) authorizes a technology-forcing standard that encourages broader adoption of an emissions-reducing technological approach that is not yet broadly used. It follows that at the time of promulgation, not every source will be prepared to adopt the BSER at once. Instead, as discussed next, the EPA's responsibility is to determine that the technology can be adopted in a reasonable period of time, and to base its requirements on this understanding.

iii. Compliance Timeframe

The preceding subsections have shown various circumstances under which the EPA may determine that a system of emission reduction is "adequately demonstrated." In order to establish that a system is appropriate for the source category as a whole, the EPA must also demonstrate that the industry can deploy the technology at scale in the compliance timeframe. The D.C. Circuit has stated that the EPA may determine a "system of emission reduction" to be "adequately demonstrated" if the EPA reasonably projects that it may be more broadly deployed with adequate lead time. This view is well-grounded in the purposes of CAA section 111(a)(1), discussed above, which aim to control dangerous air pollution by allowing for standards which encourage more widespread adoption of a technology demonstrated at individual plants.

As a practical matter, CAA section 111's allowance for lead time recognizes that existing pollution control systems may be complex and may require a predictable amount of time for sources across the source category to be able to design, acquire, install, test, and begin to operate them.[223] Time may also be required to allow for the development of skilled labor, and materials like steel, concrete, and speciality parts. Accordingly, in setting 111 standards for both new and existing sources, the EPA has typically allowed for some amount of time before sources must demonstrate compliance with the standards. For instance, in the 2015 NSPS for residential wood heaters, the EPA established a "stepped compliance approach" which phased in requirements over 5 years to "allow manufacturers lead time to develop, test, field evaluate and certify current technologies" across their model lines.[224] The EPA also allowed for a series of phase-ins of various requirements in the 2023 oil and gas NSPS.[225] For example: the EPA finalized a compliance deadline for process controllers allowing for 1 year from the effective date of the final rule, to allow for delays in equipment availability; [226] the EPA established a 1-year lead time period for pumps, also in response to possible equipment and labor shortages; [227] and the EPA built in 24 months between publication in the **Federal Register** and the commencement of a requirement to end routine flaring and route associated gas to a sales line.[228]

Finally, the EPA's longstanding regulations for new source performance standards under CAA section 111 specifically authorize a minimum period for lead time. Pursuant to 40 CFR 60.11, compliance with CAA section 111 standards is generally determined in accordance with performance tests conducted under 40 CFR 60.8. Both of these regulatory provisions were adopted in 1971. Under 40 CFR 60.8, source performance is generally measured via performance tests, which must typically be carried out "within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act. . . ." [229] The fact that this provision has been in place for over 50 years indicates that the EPA has long recognized the need for lead time for at least one component of control development.[230]

c. Costs

Under CAA section 111(a)(1), in determining whether a particular emission control is the "best system of emission reduction . . . adequately demonstrated," the EPA is required to take into account "the cost of achieving [the emission] reduction." Although the CAA does not describe how the EPA is to account for costs to affected sources, the D.C. Circuit has formulated the cost standard in various ways, including stating that the EPA may not adopt a standard the cost of which would be "excessive" or "unreasonable." [231] [232]

[218] 198 F.3d 930 (D.C. Cir. 1999).

[219] *See id.* at 933–34.

[220] *Id.* at 934 (emphasis added).

[221] 486 F.2d 375 (D.C. Cir. 1973). *See also Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), which supports the point that EPA may extrapolate from testing results, rather than relying on consistent performance, to identify an appropriate system and standard based on that system. In that case, EPA analyzed scrubber performance by considering performance during short-term testing periods. *See id.* at 377.

[222] 486 F.2d at 435–36.

[223] As discussed above, although the EPA is not relying on this point for purposes of these rules, it should be noted that the EPA may determine a system of emission reduction to be adequately demonstrated based on some amount of projection, even if some aspects of the system are still in development. Thus, the authorization for lead time accommodates the development of projected technology.

[224] *See* Standards of Performance for New Residential Wood Heaters, New Residential Hydronic Heaters and Forced-Air Furnaces, 80 FR 13672, 13676 (March 16, 2015).

[225] *See* Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. 89 FR 16943 (March 8, 2024).

[226] *See id.* at 16929.

[227] *See id.* at 16937.

[228] *See id.* at 16886.

[229] 40 CFR 60.8.

[230] For further discussion of lead time in the context of this rulemaking, see section VIII.F.

[231] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981). *See* 79 FR 1430, 1464 (January 8, 2014); *Lignite Energy Council,* 198 F.3d at 933 (costs may not be "exorbitant"); *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975) (costs may not be "greater than the industry could bear and survive").

[232] These cost formulations are consistent with the legislative history of CAA section 111. The 1977 House Committee Report noted:

In the [1970] Congress [sic: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.

1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

The implicit consideration of economic factors in determining whether technology is "available" should not affect the usefulness of this section. The overriding purpose of this section would be to

The EPA has discretion in its consideration of cost under section 111(a), both in determining the appropriate level of costs and in balancing costs with other BSER factors.[233] To determine the BSER, the EPA must weigh the relevant factors, including the cost of controls and the amount of emission reductions, as well as other factors.[234]

The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance. In several cases, the court upheld standards that entailed significant costs, consistent with Congress's view that "the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business." [235] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973); [236] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding NSPS imposing controls on SO_2 emissions from coal-fired power plants when the "cost of the new controls . . . is substantial. The EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.").

In its CAA section 111 rulemakings, the EPA has frequently used a cost-effectiveness metric, which determines the cost in dollars for each ton or other quantity of the regulated air pollutant removed through the system of emission reduction. *See, e.g.,* 81 FR 35824 (June 3, 2016) (NSPS for GHG and VOC emissions for the oil and natural gas source category); 71 FR 9866, 9870 (February 27, 2006) (NSPS for NO_X, SO_2, and PM emissions from fossil fuel-fired electric utility steam generating units); 61 FR 9905, 9910 (March 12, 1996) (NSPS and emission guidelines for nonmethane organic compounds and landfill gas from new and existing municipal solid waste landfills); 50 FR 40158 (October 1, 1985) (NSPS for SO_2 emissions from sweetening and sulfur recovery units in natural gas processing plants). This metric allows the EPA to compare the amount a regulation would require sources to pay to reduce a particular pollutant across regulations and industries. In rules for the electric power sector, the EPA has also looked at a metric that determines the dollar increase in the cost of a MWh of electricity generated by the affected sources due to the emission controls, which shows the cost of controls relative to the output of electricity. *See* section VII.C.1.a.ii of this preamble, which discusses \$/MWh costs of the Good Neighbor Plan for the 2015 Ozone NAAQS (88 FR 36654; June 5, 2023) and the Cross-State Air Pollution Rule (CSAPR) (76 FR 48208; August 8, 2011). This metric facilitates comparing costs across regulations and pollutants. In these final actions, as explained herein, the EPA looks at both of these metrics, in addition to other cost evaluations, to assess the cost reasonableness of the final requirements. The EPA's consideration of cost reasonableness in this way meets the statutory requirement that the EPA take into account "the cost of achieving [the emission] reduction" under section 111(a)(1).

d. Non-Air Quality Health and Environmental Impact and Energy Requirements

Under CAA section 111(a)(1), the EPA is required to take into account "any nonair quality health and environmental impact and energy requirements" in determining the BSER. Non-air quality health and environmental impacts may include the impacts of the disposal of byproducts of the air pollution controls, or requirements of the air pollution control equipment for water. *Portland Cement Ass'n* v. *Ruckelshaus,* 465 F.2d 375, 387–88 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974). Energy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs.

e. Sector or Nationwide Component of Factors in Determining the BSER

Another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[237] The D.C. Circuit based this interpretation—which it made in the 1981 *Sierra Club* v. *Costle* case regarding the NSPS for new power plants—on a review of the legislative history, stating,

> [T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[238]

The court has upheld EPA rules that the EPA "justified . . . in terms of the policies of the Act," including balancing long-term national and regional impacts. For example, the court upheld a standard of performance for SO_2 emissions from new coal-fired power plants on grounds that it—

> reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. . . .[239]

The EPA interprets this caselaw to authorize it to assess the impacts of the controls it is considering as the BSER, including their costs and implications for the energy system, on a sector-wide, regional, or national basis, as appropriate. For example, the EPA may assess whether controls it is considering would create risks to the reliability of the electricity system in a particular area or nationwide and, if they would, to reject those controls as the BSER.

f. "Best"

In determining which adequately demonstrated system of emission reduction is the "best," the EPA has broad discretion. In *AEP* v. *Connecticut,* 564 U.S. 410, 427 (2011), the Supreme Court explained that under CAA section 111, "[t]he appropriate amount of regulation in any particular greenhouse gas-producing sector cannot be prescribed in a vacuum: . . . informed assessment of competing interests is required. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance. The Clean Air Act entrusts such complex balancing to the EPA in the first instance, in combination with state regulators. Each "standard of performance" the EPA sets must "tak[e] into account the cost of achieving [emissions] reduction and any nonair quality health and environmental impact and energy requirements." (paragraphing revised; citations omitted)).

prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91–1196 at 16.

[233] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[234] *Id.* (EPA's conclusion that the high cost of control was acceptable was "a judgment call with which we are not inclined to quarrel").

[235] 1977 House Committee Report at 184.

[236] The costs for these standards were described in the rulemakings. See 36 FR 24876 (December 23, 1971), 37 FR 5769 (March 21, 1972).

[237] See 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

[238] *Sierra Club* v. *Costle,* 657 F.2d at 331 (citations omitted) (citing legislative history).

[239] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583–84; June 11, 1979).

Likewise, in *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,'' [240] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard,'' including the amount of emission reductions, the cost of the controls, and the non-air quality environmental impacts and energy requirements.[241] And in *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them . . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant . . . . EPA [has] considerable discretion under section 111.[242]

Importantly, the courts recognize that the EPA must consider several factors and that determining what is ''best'' depends on how much weight to give the factors. In promulgating certain standards of performance, the EPA may give greater weight to particular factors than it does in promulgating other standards of performance. Thus, the determination of what is ''best'' is complex and necessarily requires an exercise of judgment. By analogy, the question of who is the ''best'' sprinter in the 100-meter dash primarily depends on only one criterion—speed—and therefore is relatively straightforward, whereas the question of who is the ''best'' baseball player depends on a more complex weighing of multiple criteria and therefore requires a greater exercise of judgment.

The term ''best'' also authorizes the EPA to consider factors in addition to the ones enumerated in CAA section 111(a)(1), that further the purpose of the statute. In *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973), the D.C. Circuit held that under CAA section 111(a)(1) as it read prior to the enactment of the 1977 CAA Amendments that added a requirement that the EPA take account of non-air quality environmental impacts, the EPA must consider ''counter-productive environmental effects'' in Determining the BSER. *Id.* at 385. The court elaborated: ''The standard of the 'best system' is comprehensive, and we cannot imagine that Congress intended that 'best' could apply to a system which did more damage to water than it prevented to air.'' *Id.,* n.42. In *Sierra Club* v. *Costle,* 657 F.2d at 326, 346–47, the court added that the EPA must consider the amount of emission reductions and technology advancement in determining BSER, as discussed in section V.C.2.g of this preamble.

The court's view that ''best'' includes additional factors that further the purpose of CAA section 111 is a reasonable interpretation of that term in its statutory context. The purpose of CAA section 111 is to reduce emissions of air pollutants that endanger public health or welfare. CAA section 111(b)(1)(A). The court reasonably surmised that the EPA's determination of whether a system of emission reduction that reduced certain air pollutants is ''best'' should be informed by impacts that the system may have on other pollutants that affect public or welfare. *Portland Cement Ass'n,* 486 F.2d at 385. The Supreme Court confirmed the D.C. Circuit's approach in *Michigan* v. *EPA,* 576 U.S. 743 (2015), explaining that administrative agencies must engage in ''reasoned decisionmaking'' that, in the case of pollution control, cannot be based on technologies that ''do even more damage to human health'' than the emissions they eliminate. *Id.* at 751–52. After *Portland Cement Ass'n,* Congress revised CAA section 111(a)(1) to make explicit that in determining whether a system of emission reduction is the ''best,'' the EPA should account for non-air quality health and environmental impacts. By the same token, the EPA takes the position that in determining whether a system of emission reduction is the ''best,'' the EPA may account for the impacts of the system on air pollutants other than the ones that are the subject of the CAA section 111 regulation.[243] We discuss immediately below other factors that the D.C. Circuit has held the EPA should account for in determining what system is the ''best.''

g. Amount of Emissions Reductions

Consideration of the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction'' is implicit in the plain language of CAA section 111(a)(1)—the EPA must choose the *best* system of *emission reduction.* Indeed, consistent with this plain language and the purpose of CAA section 111, the EPA must consider the quantity of emissions at issue. *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) (''we 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'').[244] The fact that the purpose of a ''system of emission reduction'' is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the court's view that in determining whether a ''system of emission reduction'' is the ''best,'' the EPA must consider the amount of emission reductions that the system would yield. Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term ''system of emission reduction'' or the term ''best'' may reasonably be read to allow that discretion.

h. Expanded Use and Development of Technology

The D.C. Circuit has long held that Congress intended for CAA section 111

[240] *Sierra Club* v. *Costle,* 657 F.2d at 319.

[241] *Sierra Club* v. *Costle,* 657 F.2d at 321; *see also New York* v. *Reilly,* 969 F.2d at 1150 (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, ''the Administrator is free to exercise [her] discretion'' in promulgating an NSPS).

[242] *Lignite Energy Council,* 198 F.3d at 933 (paragraphing revised for convenience). *See New York* v. *Reilly,* 969 F.2d 1147, 1150 (D.C. Cir. 1992) (''Because Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area.''); *see also NRDC* v. *EPA,* 25 F.3d 1063, 1071 (D.C. Cir. 1994) (The EPA did not err in its final balancing because ''neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decisionmaking.'').

[243] See generally *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review—Supplemental Notice of Proposed Rulemaking,* 87 FR 74765 (December 6, 2022) (proposing the BSER for reducing methane and VOC emissions from natural gas-driven controllers in the oil and natural gas sector on the basis of, among other things, impacts on emissions of criteria pollutants). In this preamble, for convenience, the EPA generally discusses the effects of controls on non-GHG air pollutants along with the effects of controls on non-air quality health and environmental impacts.

[244] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system of emission reduction'' to read, ''best technological system of continuous emission reduction.'' As noted above, the 1990 CAAA deleted ''technological'' and ''continuous'' and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of the 1977 CAAA phrase in *Sierra Club* v. *Costle* to require consideration of the amount of air emissions focused on the term ''best,'' and the terms ''technological'' and ''continuous'' were irrelevant to its analysis. It thus remains valid for the 1990 CAAA phrase ''best system of emission reduction.''

to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the "best system of emission reduction." *See Sierra Club* v. *Costle,* 657 F.2d at 346–47. The court has grounded its reading in the statutory text of CAA 111(a)(1), defining the term "standard of performance." [245] In addition, the court's interpretation finds support in the legislative history.[246] The legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (1) The development of technology that may be treated as the "best system of emission reduction . . . adequately demonstrated;" under CAA section 111(a)(1); [247] (2) the expanded use of the best demonstrated technology; [248] and (3) the development of emerging technology.[249] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it because technological innovation may be considered an element of the term "best," particularly in light of Congress's emphasis on technological innovation.

i. Achievability of the Degree of Emission Limitation

For new sources, CAA section 111(b)(1)(B) and (a)(1) provides that the EPA must establish "standards of performance," which are standards for emissions that reflect the degree of emission limitation that is "achievable" through the application of the BSER. A standard of performance is "achievable" if a technology can reasonably be projected to be available to an individual source at the time it is constructed that will allow it to meet the standard.[250] Moreover, according to the court, "[a]n 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 necessarily be routinely achieved within the industry prior to its adoption." [251] To be achievable, a standard "must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'costs' of compliance." [252] To show a standard is achievable, the EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard." [253]

Although the courts have established these standards for achievability in cases concerning CAA section 111(b) new source standards of performance, generally comparable standards for achievability should apply under CAA section 111(d), although the BSER may differ in some cases as between new and existing sources due to, for example, higher costs of retrofit. 40 FR 53340 (November 17, 1975). For existing sources, CAA section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include "standards of performance." As the Supreme Court has recognized, this provision requires the EPA to promulgate emission guidelines that determine the BSER for a source category and then identify the degree of emission limitation achievable by application of the BSER. *See West Virginia* v. *EPA,* 597 U.S. at 710.[254]

The EPA has promulgated emission guidelines on the basis that the existing sources can achieve the degree of emission limitation described therein, even though under the RULOF provision of CAA section 111(d)(1), the state retains discretion to apply standards of performance to individual sources that are less stringent, which indicates that Congress recognized that the EPA may promulgate emission guidelines that are consistent with CAA section 111(d) even though certain individual sources may not be able to achieve the degree of emission limitation identified therein by applying the controls that the EPA determined to be the BSER. Note further that this requirement that the emission limitation be "achievable" based on the "best system of emission reduction . . . adequately demonstrated" indicates that the technology or other measures that the EPA identifies as the BSER must be technically feasible.

3. EPA Promulgation of Emission Guidelines for States To Establish Standards of Performance

CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a procedure similar to that provided by CAA section 110 under which states submit state plans that establish "standards of performance" for emissions of certain air pollutants from sources which, if they were new sources, would be regulated under CAA section 111(b), and that provide for the implementation and enforcement of such standards of performance. The term "standard of performance" is defined under CAA section 111(a)(1), quoted above. Thus, CAA sections 111(a)(1) and (d)(1) collectively require the EPA to determine the degree of emission limitation achievable through application of the BSER to existing sources and to establish regulations under which states establish standards of performance reflecting that degree of emission limitation. The EPA addresses both responsibilities through its emission guidelines, as well as through its general implementing regulations for CAA section 111(d). Consistent with the statutory requirements, the general implementing regulations require that the EPA's emission guidelines reflect—

> the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction and any non-air quality health and environmental

[245] *Sierra Club* v. *Costle,* 657 F.2d at 346 ("Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and non-air quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.").

[246] See S. Rep. No. 91–1196 at 16 (1970) ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources"); S. Rep. No. 95–127 at 17 (1977) (cited in *Sierra Club* v. *Costle,* 657 F.2d at 346 n.174) ("The section 111 Standards of Performance . . . sought to assure the use of available technology and to stimulate the development of new technology").

[247] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must "look[ ] toward what may fairly be projected for the regulated future, rather than the state of the art at present").

[248] 1970 Senate Committee Report No. 91–1196 at 15 ("The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems").

[249] *Sierra Club* v. *Costle,* 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

[250] *Sierra Club* v. *Costle,* 657 F.2d 298, 364, n.276 (D.C. Cir. 1981).

[251] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[252] *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).

[253] *Sierra Club* v. *Costle,* 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the " 'feedstock, operation, size and age' of the source." *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to "generalize from a sample of one when one is the only available sample, or when that one is shown to be representative of the regulated industry along relevant parameters." *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

[254] 40 CFR 60.21(e), 60.21a(e).

impact and energy requirements) the Administrator has determined has been adequately demonstrated from designated facilities.[255]

Following the EPA's promulgation of emission guidelines, each state must establish standards of performance for its existing sources, which the EPA's regulations call ''designated facilities.'' [256] Such standards of performance must reflect the degree of emission limitation achievable through application of the best system of emission reduction as determined by the EPA, which the Agency may express as a presumptive standard of performance in the applicable emission guidelines.

While the standards of performance that states establish in their plans must generally be no less stringent than the degree of emission limitation determined by the EPA,[257] CAA section 111(d)(1) also requires that the EPA's regulations ''permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' Consistent with this statutory direction, the EPA's general implementing regulations for CAA section 111(d) provide a framework for states' consideration of remaining useful life and other factors (referred to as ''RULOF'') when applying a standard of performance to a particular source. In November 2023, the EPA finalized clarifications to its regulations governing states' consideration of RULOF to apply less stringent standards of performance to particular existing sources. As amended, these regulations provide that states may apply a standard of performance to a particular designated facility that is less stringent than, or has a longer compliance schedule than, otherwise required by the applicable emission guideline taking into consideration that facility's remaining useful life and other factors. To apply a less stringent standard of performance or longer compliance schedule, the state must demonstrate with respect to each facility (or class of such facilities), that the facility cannot reasonably achieve the degree of emission limitation determined by the EPA based on unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility or technical infeasibility of installing necessary control equipment; or other circumstances specific to the facility. In doing so, the state must demonstrate that there are fundamental differences between the information specific to a facility (or class of such facilities) and the information the EPA considered in determining the degree of emission limitation achievable through application of the BSER or the compliance schedule that make achieving such degree of emission reduction or meeting such compliance schedule unreasonable for that facility.

In addition, under CAA section 116, states may establish standard of performances that are more stringent than the presumptive standards of performance contained in the EPA's emission guidelines.[258] The state must include the standards of performance in their state plans and submit the plans to the EPA for review according to the procedures established in the Agency's general implementing regulations for CAA section 111(d).[259] Under CAA section 111(d)(2)(A), the EPA approves state plans that are determined to be ''satisfactory.'' CAA section 111(d)(2)(A) also gives the Agency ''the same authority'' as under CAA section 110(c) to promulgate a Federal plan in cases where a state fails to submit a satisfactory state plan.

VI. ACE Rule Repeal

The EPA is finalizing repeal of the ACE Rule. The EPA proposed to repeal the ACE Rule and did not receive significant comments objecting to the proposal. The EPA is finalizing the proposal largely as proposed. A general summary of the ACE Rule, including its regulatory and judicial history, is included in section V.B.4 of this preamble. The EPA repeals the ACE Rule on three grounds that each independently justify the rule's repeal.

First, as a policy matter, the EPA concludes that the suite of heat rate improvements (HRI) the ACE Rule selected as the BSER is not an appropriate BSER for existing coal-fired EGUs. In the EPA's technical judgment, the suite of HRI set forth in the ACE Rule provide negligible CO_2 reductions at best and, in many cases, may increase CO_2 emissions because of the ''rebound effect,'' as explained in section VII.D.4.a.iii of this preamble. These concerns, along with the EPA's experience in implementing the ACE Rule, cast doubt that the ACE Rule would achieve emission reductions and increase the likelihood that the ACE Rule could make CO_2 pollution worse. As a result, the EPA has determined it is appropriate to repeal the rule, and to reevaluate whether other technologies constitute the BSER.

Second, even assuming the ACE Rule's rejection of CCS and natural gas co-firing was supported at the time, the ACE Rule's rationale for rejecting CCS and natural gas co-firing as the BSER no longer applies because of new factual developments. Since the ACE Rule was promulgated, changes in the power industry, developments in the costs of controls, and new federal subsidies have made other controls more broadly available and less expensive. Considering these developments, the EPA has determined that co-firing with natural gas and CCS are the BSER for certain subcategories of sources as described in section VII.C of this preamble, and that the HRI technologies adopted by the ACE Rule are not the BSER. Thus, repeal of the ACE Rule is proper on this ground as well.

Third, the EPA concludes that the ACE Rule conflicted with CAA section 111 and the EPA's implementing regulations because it did not specifically identify the BSER or the ''degree of emission limitation achievable though application of the [BSER].'' Instead, the ACE Rule described only a broad range of values as the ''degree of emission limitation achievable.'' In doing so, the rule did not provide the states with adequate guidance on the degree of emission limitation that must be reflected in the standards of performance so that a state plan would be approvable by the EPA. The ACE Rule is repealed for this reason also.

A. Summary of Selected Features of the ACE Rule

The ACE Rule determined that the BSER for coal-fired EGUs was a ''list of 'candidate technologies,' '' consisting of seven types of the ''most impactful HRI technologies, equipment upgrades, and best operating and maintenance practices,'' (84 FR 32536; July 8, 2019), including, among others, ''Boiler Feed Pumps'' and ''Redesign/Replace Economizer.'' *Id.* at 32537 (table 1). The rule provided a range of improvements

[255] 40 CFR 60.21a(e).

[256] 40 CFR 60.21a(b), 60.24a(b).

[257] As the Supreme Court explained in *West Virginia* v. *EPA,* ''Although the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d).'' 597 U.S. at 710. The Court elaborated that ''[t]he Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, 'the best system of emission reduction . . . that has been adequately demonstrated for [existing covered] facilities.' 40 CFR 60.22(b)(5) (2021); see also 80 FR 64664, and n.1. The 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. See §§ 60.23, 60.24; 42 U.S.C. 7411(d)(1).'' *Id.*

[258] 40 CFR 60.24a(i).

[259] See generally 40 CFR 60.23a–60.28a.

in heat rate that each of the seven "candidate technologies" could achieve if applied to coal-fired EGUs of different capacities. For six of the technologies, the expected level of improvement in heat rate ranged from 0.1–0.4 percent to 1.0–2.9 percent, and for the seventh technology, "Improved Operating and Maintenance (O&M) Practices," the range was "0 to >2%." *Id.* The ACE Rule explained that states must review each of their designated facilities, on either a source-by-source or group-of-sources basis, and "evaluate the applicability of each of the candidate technologies." *Id.* at 32550. States were to use the list of HRI technologies "as guidance but will be expected to conduct unit-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies." *Id.* at 32538.

The ACE Rule emphasized that states had "inherent flexibility" in evaluating candidate technologies with "a wide range of potential outcomes." *Id.* at 32542. The ACE Rule provided that states could conclude that it was not appropriate to apply some technologies. *Id.* at 32550. Moreover, if a state decided to apply a particular technology to a particular source, the state could determine the level of heat rate improvement from the technology could be anywhere within the range that the EPA had identified for that technology, or even outside that range. *Id.* at 32551. The ACE Rule stated that after the state evaluated the technologies and calculated the amount of HRI in this way, it should determine the standard of performance 0that the source could achieve, *Id.* at 32550, and then adjust that standard further based on the application of source-specific factors such as remaining useful life. *Id.* at 32551.

The ACE Rule then identified the process by which states had to take these actions. States must "evaluat[e] each" of the seven candidate technologies and provide a summary, which "include[s] an evaluation of the . . . degree of emission limitation achievable through application of the technologies." *Id.* at 32580. Then, the state must provide a variety of information about each power plant, including, the plant's "annual generation," "CO_2 emissions," "[f]uel use, fuel price, and carbon content," "operation and maintenance costs," "[h]eat rates," "[e]lectric generating capacity," and the "timeline for implementation," among other information. *Id.* at 32581. The EPA explained that the purpose of this data was to allow the Agency to "adequately and appropriately review the plan to determine whether it is satisfactory." *Id.* at 32558.

The ACE Rule projected a very low level of overall emission reduction if states generally applied the set of candidate technologies to their sources. The rule was projected to achieve a less-than-1-percent reduction in power-sector CO_2 emissions by 2030.[260] Further, the EPA also projected that it would increase CO_2 emissions from power plants in 15 states and the District of Columbia because of the "rebound effect" as coal-fired sources implemented HRI measures and became more efficient. This phenomenon is explained in more detail in section VII.D.4.a.iii of this document.[261]

The ACE Rule considered several other control measures as the BSER, including co-firing with natural gas and CCS, but rejected them. The ACE Rule rejected co-firing with natural gas primarily on grounds that it was too costly in general. 84 FR 32545 (July 8, 2019). The rule also concluded that generating electricity by co-firing natural gas in a utility boiler would be an inefficient use of the gas when compared to combusting it in a combustion turbine. *Id.* The ACE Rule rejected CCS on grounds that it was too costly. *Id.* at 32548. The rule identified the high capital and operating costs of CCS and noted the fact that the IRC section 45Q tax credit, as it then applied, would provide only limited benefit to sources. *Id.* at 32548–49.

B. Developments Undermining ACE Rule's Projected Emission Reductions

The EPA's first basis for repealing the ACE Rule is that it is unlikely that—if implemented—the rule would reduce emissions, and implementation could increase CO_2 emissions instead. Thus, the EPA concludes that as a matter of policy it is appropriate to repeal the rule and evaluate anew whether other technologies qualify as the BSER.

Two factors, taken together, undermine the ACE Rule's projected emission reductions and create the risk that implementation of the ACE Rule could increase—rather than reduce—CO_2 emissions from coal-fired EGUs. First, HRI technologies achieve only limited GHG emission reductions. The ACE Rule projected that if states generally applied the set of candidate technologies to their sources, the rule would achieve a less-than-1-percent reduction in power-sector CO_2 emissions by 2030.[262] The EPA now doubts that even these minimal reductions would be achieved. The ACE Rule's projected benefits were premised in part on a 2009 technical report by Sargent & Lundy that evaluated the effects of HRI technologies. In 2023, Sargent & Lundy issued an updated report which details that the HRI selected as the BSER in the ACE Rule would bring fewer emissions reductions than estimated in 2009. The 2023 report concludes that, with few exceptions, HRI technologies are less effective at reducing CO_2 emissions than assumed in 2009. Further reinforcing the conclusion that HRIs would bring few reductions, the 2023 report also concluded that most sources had already optimized application of HRIs, and so there are fewer opportunities to reduce emissions than previously anticipated.[263]

Second, for a subset of sources, HRI are likely to cause a "rebound effect" leading to an increase in GHG emissions for those sources. The rebound effect is explained in detail in section VII.D.4.a.iii of this preamble. The ACE Rule's analysis projected that the rule would increase CO_2 emissions from power plants in 15 states and the District of Columbia. The EPA's modeling projections assumed that, consistent with the rule, some sources would impose a small degree of efficiency improvements. The modeling showed that, as a consequence of these improvements, the rule would increase absolute emissions at some coal-fired sources as these sources became more efficient and displaced lower emitting sources like natural gas-fired EGUs.[264]

Even though the ACE Rule was projected to increase emissions in many states, these states were nevertheless obligated under the rule to assemble detailed state plans that evaluated available technologies and the performance of each existing coal-fired power plant, as described in section IX.A of this preamble. For example, the state was required to analyze the plant's "annual generation," "CO_2 emissions," "[f]uel use, fuel price, and carbon content," "operation and maintenance

[260] ACE Rule RIA 3–11, table 3–3.

[261] The rebound effect becomes evident by comparing the results of the ACE Rule IPM runs for the 2018 reference case, EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case,* Document ID No. EPA–HQ–OAR–2017–0355–26720, and for the "Illustrative ACE Scenario. *IPM State-Level Emissions: Illustrative ACE Scenario,* Document ID No. EPA–HQ–OAR–2017–0355–26724.

[262] ACE Rule RIA 3–11, table 3–3.

[263] Sargent and Lundy. Heat Rate Improvement Method Costs and Limitations Memo. Available in Docket ID No. EPA–HQ–OAR–2023–0072.

[264] See EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case,* Document ID No. EPA–HQ–OAR–2017–0355–26720 (providing ACE reference case); *IPM State-Level Emissions: Illustrative ACE Scenario,* Document ID No. EPA–HQ–OAR–2017–0355–26724 (providing illustrative scenario).

costs,'' ''[h]eat rates,'' ''[e]lectric generating capacity,'' and the ''timeline for implementation,'' among other information. 84 FR 32581 (July 8, 2019). The risk of an increase in emissions raises doubts that the HRI for coal-fired sources satisfies the statutory criteria to constitute the BSER for this category of sources. The core element of the BSER analysis is whether the emission reduction technology selected reduces emissions. *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 441 (D.C. Cir. 1973) (noting ''counter productive environmental effects'' raises questions as to whether the BSER selected was in fact the ''best''). Moreover, this evaluation and the imposition of standards of performance was mandated even though the state plan would lead to an *increase* rather than decrease CO_2 emissions. Imposing such an obligation on states under these circumstances was arbitrary.

The EPA's experience in implementing the ACE Rule reinforces these concerns. After the ACE Rule was promulgated, one state drafted a state plan that set forth a standard of performance that allowed the affected source to increase its emission rate. The draft partial plan would have applied to one source, the Longview Power, LLC facility, and would have established a standard of performance, based on the state's consideration of the ''candidate technologies,'' that was higher (*i.e.,* less stringent) than the source's historical emission rate. Thus, the draft plan would not have achieved any emission reductions from the source, and instead would have allowed the source to *increase* its emissions, if it had been finalized.[265]

Because there is doubt that the minimal reductions projected by the ACE Rule would be achieved, and because the rebound effect could lead to an increase in emissions for many sources in many states, the EPA concludes that it is appropriate to repeal the ACE Rule and reevaluate the BSER for this category of sources.

C. Developments Showing That Other Technologies Are the BSER for This Source Category

Since the promulgation of the ACE Rule in 2019, the factual underpinnings of the rule have changed in several ways and lead the EPA to determine that HRI are not the BSER for coal-fired power plants. This reevaluation is consistent with *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009). There, the Supreme Court explained that an agency issuing a new policy ''need not demonstrate to a court's satisfaction that the reasons for the new policy are *better* than the reasons for the old one.'' Instead, ''it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates.'' *Id.* at 514–16 (emphasis in original; citation omitted).

Along with changes in the anticipated reductions from HRI, it makes sense for the EPA to reexamine the BSER because the costs of two control measures, co-firing with natural gas and CCS, have fallen for sources with longer-term operating horizons. As noted, the ACE Rule rejected natural gas co-firing as the BSER on grounds that it was too costly and would lead to inefficient use of natural gas. But as discussed in section VII.C.2.b of this preamble, the costs of natural gas co-firing are presently reasonable, and the EPA concludes that the costs of co-firing 40 percent by volume natural gas are cost-effective for existing coal-fired EGUs that intend to operate after January 1, 2032, and cease operation before January 1, 2039. In addition, changed circumstances—including that natural gas is available in greater amounts, that many coal-fired EGUs have begun co-firing with natural gas or converted wholly to natural-gas, and that there are fewer coal-fired EGUs in operation—mitigate the concerns the ACE Rule identified about inefficient use of natural gas.

Similarly, the ACE Rule rejected CCS as the BSER on grounds that it was too costly. But the costs of CCS have substantially declined, as discussed in section VII.C.1.a.ii of the preamble, partly because of developments in the technology that have lowered capital costs, and partly because the IRA extended and increased the IRS section 45Q tax credit so that it defrays a higher portion of the costs of CCS. Accordingly, for coal-fired EGUs that will continue to operate past 2039, the EPA concludes that the costs of CCS are reasonable, as described in section VII.C.1.a.ii of the preamble.

The emission reductions from these two technologies are substantial. For long-term coal-fired steam generating units, the BSER of 90 percent capture CCS results in substantial CO_2 emissions reductions amounting to emission rates that are 88.4 percent lower on a lb/MWh-gross basis and 87.1 percent lower on a lb/MWh-net basis compared to units without capture, as described in section VII.C.2.b.iv of this preamble. For medium term units, the BSER of 40 percent natural gas co-firing achieves CO_2 stack emissions reductions of 16 percent, as described in section VII.C.2.b.iv of this preamble. Given the availability of more effective, cost-reasonable technology, the EPA concludes that HRIs are not the BSER for all coal-fired EGUs.

The EPA is thus finalizing a new policy for coal-fired power plants. This rule applies to those sources that intend to operate past January 1, 2032. For sources that intend to cease operations after January 1, 2032, but before January 1, 2039, the EPA concludes that the BSER is co-firing 40 percent by volume natural gas. The EPA concludes this control measure is appropriate because it achieves substantial reductions at reasonable cost. In addition, the EPA believes that because a large supply of natural gas is available, devoting part of this supply for fuel for a coal-fired steam generating unit in place of a percentage of the coal burned at the unit is an appropriate use of natural gas and will not adversely impact the energy system, as described in section VII.C.2.b.iii(B) of this preamble. For sources that intend to operate past January 1, 2039, the EPA concludes that the BSER is CCS with 90 percent capture of CO_2. The EPA believes that this control measure is appropriate because it achieves substantial reductions at reasonable cost, as described in section VII.C.1 of this preamble.

The EPA is not concluding that HRI is the BSER for any coal-fired EGUs. As discussed in section VII.D.4.a, the EPA does not consider HRIs an appropriate BSER for coal-fired EGUs because these technologies would achieve few, if any, emissions reductions and may increase emissions due to the rebound effect. Most importantly, changed circumstances show that co-firing natural gas and CCS are available at reasonable cost, and will achieve more GHG emissions reductions. Accordingly, the EPA believes that HRI do not qualify as the BSER for any coal-fired EGUs, and that other approaches meet the statutory standard. On this basis, the EPA repeals the ACE Rule.

D. Insufficiently Precise Degree of Emission Limitation Achievable From Application of the BSER

The third independent reason why the EPA is repealing the ACE Rule is that the rule did not identify with sufficient specificity the BSER or the degree of emission limitation achievable through the application of the BSER. Thus, states lacked adequate guidance on the BSER they should consider and

[265] West Virginia CAA § 111(d) Partial Plan for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (EGUs), *https://dep.wv.gov/daq/publicnoticeandcomment/Documents/Proposed%20WV%20ACE%20State%20Partial%20Plan.pdf.*

level of emission reduction that the standards of performance must achieve. The ACE Rule determined the BSER to be a suite of HRI ''candidate technologies,'' but did not identify with specificity the degree of emission limitation states should apply in developing standards of performance for their sources. As a result, the ACE Rule conflicted with CAA section 111 and the implementing regulations, and thus failed to provide states adequate guidance so that they could ensure that their state plans were satisfactory and approvable by the EPA.

CAA section 111 and the EPA's longstanding implementing regulations establish a clear process for the EPA and states to regulate emissions of certain air pollutants from existing sources. ''The statute directs the EPA to (1) 'determine[ ],' taking into account various factors, the 'best system of emission reduction which . . . has been adequately demonstrated,' (2) ascertain the 'degree of emission limitation achievable through the application' of that system, and (3) impose an emissions limit on new stationary sources that 'reflects' that amount.'' *West Virginia* v. *EPA*, 597 U.S. at 709 (quoting 42 U.S.C. 7411(d)). Further, ''[a]lthough the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d) . . . [and] decides the amount of pollution reduction that must ultimately be achieved.'' *Id.* at 2602.

Once the EPA makes these determinations, the state must establish ''standards of performance'' for its sources that are based on the degree of emission limitation that the EPA determines in the emission guidelines. CAA section 111(a)(1) makes this clear through its definition of ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER].'' After the EPA determines the BSER, 40 CFR 60.22(b)(5), and the degree of emission limitation achievable from application of the BSER, ''the 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.'' 597 U.S. at 710 (citing 40 CFR 60.23, 60.24; 42 U.S.C. 7411(d)(1)).

The EPA then reviews the plan and approves it if the standards of performance are ''satisfactory,'' under CAA section 111(d)(2)(A). The EPA's longstanding implementing regulations make clear that the EPA's basis for determining whether the plan is ''satisfactory'' includes that the plan must contain ''emission standards . . . no less stringent than the corresponding emission guideline(s).'' 40 CFR 60.24(c), 40 CFR 60.24a(c). In addition, under CAA section 111(d)(1), in ''applying a standard of performance to any particular source'' a state may consider, ''among other factors, the remaining useful life of the existing source to which such standard applies.'' This is also known as the RULOF provision and is discussed in section X.C.2 of this preamble.

In the ACE Rule, the EPA recognized that the CAA required it to determine the BSER and identify the degree of emission limitation achievable through application of the BSER. 84 FR 32537 (July 8, 2019). But the rule did not make those determinations. Rather, the ACE Rule described the BSER as a list of ''candidate technologies.'' And the rule described the degree of emission limitation achievable by application of the BSER as ranges of reductions from the HRI technologies. The rule thus shifted the responsibility for determining the BSER and degree of emission limitation achievable from the EPA to the states. Accordingly, the ACE Rule did not meet the CAA section 111 requirement that the EPA determine the BSER or the degree of emission limitation from application of the BSER.

As described above, the ACE Rule identified the HRI in the form of a list of seven ''candidate technologies,'' accompanied by a wide range of percentage improvements to heat rate that these technologies could provide. Indeed, for one of them, improved ''O&M'' practices (that is, operation and management practices), the range was ''0 to >2%,'' which is effectively unbounded. 84 FR 32537 (table 1) (July 8, 2019). The ACE Rule was clear that this list was simply the starting point for a state to calculate the standards of performance for its sources. That is, the seven sets of technologies were ''candidate[s]'' that the state could apply to determine the standard of performance for a source, and if the state did choose to apply one or more of them, the state could do so in a manner that yielded any percentage of heat rate improvement within the range that the EPA identified, or even outside that range. Thus, as a practical matter, the ACE Rule did not determine the BSER or any degree of emission limitation from application of the BSER, and so states had no guidance on how to craft approvable state plans. In this way, the ACE Rule did not adhere to the applicable statutory obligations. See 84 FR 32537–38 (July 8, 2019).

The only constraints that the ACE Rule imposed on the states were procedural ones, and those did not give the EPA any benchmark to determine whether a plan could be approved or give the states any certainty on whether their plan would be approved. As noted above, when a state submitted its plan, it needed to show that it evaluated each candidate technology for each source or group of sources, explain how it determined the degree of emission limitation achievable, and include data about the sources. But because the ACE Rule did not identify a BSER or include a degree of emission limitation that the standards must reflect, the states lacked specific guidance on how to craft adequate standards of performance, and the EPA had no benchmark against which to evaluate whether a state's submission was ''satisfactory'' under CAA section 111(d)(2)(A). Thus, the EPA's review of state plans would be essentially a standardless exercise, notwithstanding the Agency's longstanding view that it was ''essential'' that ''EPA review . . . [state] plans for their substantive adequacy.'' 40 FR 53342–43 (November 17, 1975). In 1975, the EPA explained that it was not appropriate to limit its review based ''solely on procedural criteria'' because otherwise ''states could set extremely lenient standards . . . so long as EPA's procedural requirements were met.'' *Id.* at 53343.

Finally, the ACE Rule's approach to determining the BSER and degree of emission limitation departed from prior emission guidelines under CAA section 111(d), in which the EPA included a numeric degree of emission limitation. See, *e.g.*, 42 FR 55796, 55797 (October 18, 1977) (limiting emission rate of acid mist from sulfuric acid plants to 0.25 grams per kilogram of acid); 44 FR 29829 (May 22, 1979) (limiting concentrations of total reduced sulfur from most of the subcategories of kraft pulp mills, such as digester systems and lime kilns, to 5, 20, or 25 ppm over 12-hour averages); 61 FR 9919 (March 12, 1996) (limiting concentration of non-methane organic compounds from solid waste landfills to 20 parts per million by volume or a 98 percent reduction). The ACE Rule did not grapple with this change in position as required by *FCC* v. *Fox Television Stations, Inc.*, 556 U.S. 502 (2009), or explain why it was appropriate to provide a boundless degree of emission limitation achievable in this context.

The EPA is finalizing the repeal the ACE Rule on this ground as well. The ACE Rule's failure to determine the BSER and the associated degree of emission limitation achievable from application of the BSER deviated from CAA section 111 and the implementing regulations. Without these determinations, the ACE Rule lacked any benchmark that would guide the states in developing their state plans, and by which the EPA could determine whether those state plans were satisfactory.

For each of these three, independent reasons, repeal of the ACE Rule is proper.

E. Withdrawal of Proposed NSR Revisions

In addition to repealing the ACE Rule, the Agency is withdrawing the proposed revisions to the NSR applicability provisions that were included the ACE Rule proposal (83 FR 44756, 44773–83; August 31, 2018). These proposed revisions would have included an hourly emissions rate test to determine NSR applicability for a modified EGU, with the expressed purpose of alleviating permitting burdens for sources undertaking HRI projects pursuant to the ACE Rule emission guidelines. The ACE Rule final action did not include the NSR revisions, and the EPA indicated in that preamble that it intended to take final action on the NSR proposal in a separate action at a later date. However, the EPA did not take a final action on the NSR revisions, and the EPA has decided to no longer pursue them and to withdraw the proposed revisions.

Withdrawal of the proposal to establish an hourly emissions test for NSR applicability for EGUs is appropriate because of the repeal of the ACE rule and the EPA's conclusion that HRI is not the BSER for coal-fired EGUs. The EPA's basis for proposing the NSR revisions was to ease permitting burdens for state agencies and sources that may result from implementing the ACE Rule. There was concern that, for sources that modified their EGU to improve the heat rate, if a source were to be dispatched more frequently because of improved efficiency (the "rebound effect"), the source could experience an increase in absolute emissions for one or more pollutants and potentially trigger major NSR requirements. The hourly emissions rate test was proposed to relieve such sources that were undertaking HRI projects to comply with their state plans from the burdens of NSR permitting, particularly in cases in which a source has an increase in annual emissions of a pollutant. However, given that this final rule BSER is not based on HRIs for coal-fired EGUs, the NSR revisions proposed as part of the ACE Rule would no longer serve the purpose that the EPA expressed in that proposal preamble.

Furthermore, in the event that any sources are increasing their absolute emissions after modifying an EGU, applicability of the NSR program is beneficial as a backstop that provides review of those situations to determine if additional controls or other emission limitations are necessary on a case-by-case basis to protect air quality. In addition, given that considerable time has passed since these EGU-specific NSR applicability revisions were proposed in 2018, should the EPA decide to pursue them at a later time, it is prudent for the Agency to propose them again at that time, accompanied with the EPA's updated context and justification to support re-proposing the NSR revisions, rather than relying on the proposal from 2018. Therefore, the EPA is withdrawing these proposed NSR revisions.

VII. Regulatory Approach for Existing Fossil Fuel-Fired Steam Generating Units

Existing fossil fuel-fired steam generation units are the largest stationary source of CO_2 emissions, emitting 909 MMT CO_2e in 2021. Recent developments in control technologies offer opportunities to reduce CO_2 emissions from these sources. The EPA's regulatory approach for these units is to require emissions reduction consistent with these technologies, where their use is cost-reasonable.

A. Overview

In this section of the preamble, the EPA identifies the BSER and degree of emission limitation achievable for the regulation of GHG emissions from existing fossil fuel-fired steam generating units. As detailed in section V of this preamble, to meet the requirements of CAA section 111(d), the EPA promulgates "emission guidelines" that identify the BSER and the degree of emission limitation achievable through the application of the BSER, and states then establish standards of performance for affected sources that reflect that level of stringency. To determine the BSER for a source category, the EPA identifies systems of emission reduction (*e.g.*, control technologies) that have been adequately demonstrated and evaluates the potential emissions reduction, costs, any non-air health and environmental impacts, and energy requirements. As described in section V.C.1 of this preamble, the EPA has broad authority to create subcategories under CAA section 111(d). Therefore, where the sources in a category differ from each other by some characteristic that is relevant for the suitability of the emission controls, the EPA may create separate subcategories and make separate BSER determinations for those subcategories.

The EPA considered the characteristics of fossil fuel-fired steam generating units that may impact the suitability of different control measures. First, the EPA observed that the type and amounts of fossil fuels—coal, oil, and natural gas—fired in the steam generating unit affect the performance and emissions reductions achievable by different control technologies, in part due to the differences in the carbon content of those fuels. The EPA recognized that many sources fire multiple types of fossil fuel. Therefore, the EPA is finalizing subcategories of coal-fired, oil-fired, and natural gas-fired steam generating units. The EPA is basing these subcategories, in part, on the amount of fuel combusted by the steam generating unit.

The EPA then considered the BSER that may be suitable for each of those subcategories of fuel type. For coal-fired steam generating units, of the available control technologies, the EPA is determining that CCS with 90 percent capture of CO_2 meets the requirements for BSER, including being adequately demonstrated and achieving significant emission reductions at reasonable cost for units operating in the long-term, as detailed in section VII.C.1.a of this preamble. Application of this BSER results in a degree of emission limitation equivalent to an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross). The compliance date for these sources is January 1, 2032.

Typically, the EPA assumes that sources subject to controls operate in the long-term.[266] See, for example, the 2015 NSPS (80 FR 64509; October 23, 2015) or the 2011 CSAPR (76 FR 48208; August 8, 2011). Under that assumption, fleet average costs for CCS are comparable to the cost metrics the EPA has previously considered to be reasonable. However, the EPA observes that about half of the capacity (87 GW out of 181 GW) of existing coal-fired steam generating units have announced plans to permanently cease operation prior to 2039, as detailed in section IV.D.3.b of this preamble, affecting the period available for those sources to amortize the capital costs of CCS.

[266] Typically, the EPA assumes that the capital costs can be amortized over a period of 15 years. As discussed in section VII.C.1.a.ii of this preamble, in the case of CCS, the IRC section 45Q tax credit, which defrays a significant portion of the costs of CCS, is available for the first 12 years of operation. Accordingly, EPA generally assumed a 12-year amortization period in determining CCS costs.

Accordingly, the EPA evaluated the costs of CCS for different amortization periods. For an amortization period of more than 7 years—such that sources operate after January 1, 2039—annualized fleet average costs are comparable to or less than the metrics of costs for controls that the EPA has previously found to be reasonable. However, the group of sources ceasing operation prior to January 1, 2039, have less time available to amortize the capital costs of CCS, resulting in higher annualized costs.

Because the costs of CCS depend on the available amortization period, the EPA is creating a subcategory for sources demonstrating that they plan to permanently cease operation prior to January 1, 2039. Instead, for this subcategory of sources, the EPA is determining that natural gas co-firing at 40 percent of annual heat input meets the requirements of BSER. Application of the natural gas co-firing BSER results in a degree of emission limitation equivalent to a 16 percent reduction in emission rate (lb CO_2/MWh-gross). Co-firing at 40 percent entails significantly less control equipment and infrastructure than CCS, and as a result, the EPA has determined that affected sources are able to implement it more quickly than CCS, by January 1, 2030. Importantly, co-firing at 40 percent also entails significantly less capital cost than CCS, and as a result, the costs of co-firing are comparable to or less than the metrics for cost reasonableness with an amortization period that is significantly shorter than the period for CCS. The EPA has determined that the costs of co-firing meet the metrics for cost reasonableness for the majority of the capacity that permanently cease operation more than 2 years after the January 1, 2030, implementation date, or after January 1, 2032 (and up to December 31, 2038), and that therefore have an amortization period of more than 2 years (and up to 9 years).

The EPA is also determining that sources demonstrating that they plan to permanently cease operation before January 1, 2032, are not subject to the 40 percent co-firing requirement. This is because their amortization period would be so short—2 years or less—that the costs of co-firing would, in general, be less comparable to the cost metrics for reasonableness for that group of sources. Accordingly, the EPA is defining the medium-term subcategory to include those sources demonstrating that they plan to permanently cease operating after December 31, 2031, and before January 1, 2039.

Considering the limited emission reductions available in light of the cost reasonableness of controls with short amortization periods, the EPA is finalizing an applicability exemption for coal-fired steam generating units demonstrating that they plan to permanently cease operation before January 1, 2032.

For natural gas- and oil-fired steam generating units, the EPA is finalizing subcategories based on capacity factor. Because natural gas- and oil-fired steam generating units with similar annual capacity factors perform similarly to one another, the EPA is finalizing a BSER of routine methods of operation and maintenance and a degree of emission limitation of no increase in emission rate for intermediate and base load subcategories. For low load natural gas- and oil-fired steam generating units, the EPA is finalizing a BSER of uniform fuels and respective degrees of emission limitation defined on a heat input basis (130 lb CO_2/MMBtu and 170 lb CO_2/MMBtu). Furthermore, the EPA is finalizing presumptive standards for natural gas- and oil-fired steam generating units as follows: base load sources (those with annual capacity factors greater than 45 percent) have a presumptive standard of 1,400 lb CO_2/MWh-gross, intermediate load sources (those with annual capacity factors greater than 8 percent and or less than or equal to 45 percent) have a presumptive standard of 1,600 lb CO_2/MWh-gross. For low load oil-fired sources, the EPA is finalizing a presumptive standard of 170 lb CO_2/MMBtu, while for low load natural gas-fired sources the EPA is finalizing a presumptive standard of 130 lb CO_2/MMBtu. A compliance date of January 1, 2030, applies for all natural gas- and oil-fired steam generating units.

The final subcategories and BSER are summarized in table 1 of this document.

TABLE 1—SUMMARY OF FINAL BSER, SUBCATEGORIES, AND DEGREES OF EMISSION LIMITATION FOR AFFECTED EGUs

Affected EGUs	Subcategory definition	BSER	Degree of emission limitation	Presumptively approvable standard of performance*
Long-term existing coal-fired steam generating units.	Coal-fired steam generating units that are not medium-term units.	CCS with 90 percent capture of CO_2.	88.4 percent reduction in emission rate (lb CO_2/MWh-gross).	88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.
Medium-term existing coal-fired steam generating units.	Coal-fired steam generating units that have demonstrated that they plan to permanently cease operations after December 31, 2031, and before January 1, 2039.	Natural gas co-firing at 40 percent of the heat input to the unit.	A 16 percent reduction in emission rate (lb CO_2/MWh-gross).	A 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.
Base load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,400 lb CO_2/MWh-gross.
Intermediate load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,600 lb CO_2/MWh-gross.
Low load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor less than 8 percent.	lower-emitting fuels	170 lb CO_2/MMBtu	170 lb CO_2/MMBtu.
Base load existing natural gas-fired steam generating units.	Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,400 lb CO_2/MWh-gross.
Intermediate load existing natural gas-fired steam generating units.	Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,600 lb CO_2/MWh-gross.

TABLE 1—SUMMARY OF FINAL BSER, SUBCATEGORIES, AND DEGREES OF EMISSION LIMITATION FOR AFFECTED EGUs—Continued

Affected EGUs	Subcategory definition	BSER	Degree of emission limitation	Presumptively approvable standard of performance *
Low load existing natural gas-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor less than 8 percent.	lower-emitting fuels	130 lb CO_2/MMBtu	130 lb CO_2/MMBtu.

* Presumptive standards of performance are discussed in detail in section X of the preamble. While states establish standards of performance for sources, the EPA provides presumptively approvable standards of performance based on the degree of emission limitation achievable through application of the BSER for each subcategory. Inclusion in this table is for completeness.

B. Applicability Requirements and Fossil Fuel-Type Definitions for Subcategories of Steam Generating Units

In this section of the preamble, the EPA describes the rationale for the final applicability requirements for existing fossil fuel-fired steam generating units. The EPA also describes the rationale for the fuel type definitions and associated subcategories.

1. Applicability Requirements

For the emission guidelines, the EPA is finalizing that a designated facility [267] is any fossil fuel-fired electric utility steam generating unit (*i.e.*, utility boiler or IGCC unit) that: (1) was in operation or had commenced construction on or before January 8, 2014; [268] (2) serves a generator capable of selling greater than 25 MW to a utility power distribution system; and (3) has a base load rating greater than 260 GJ/h (250 million British thermal units per hour (MMBtu/h)) heat input of fossil fuel (either alone or in combination with any other fuel). Consistent with the implementing regulations, the term ''designated facility'' is used throughout this preamble to refer to the sources affected by these emission guidelines.[269] For the emission guidelines, consistent with prior CAA section 111 rulemakings concerning EGUs, the term ''designated facility'' refers to a single EGU that is affected by these emission guidelines. The rationale for the final applicability requirements is the same as that for 40 CFR part 60, subpart TTTT (80 FR 64543–44; October 23, 2015). The EPA includes that discussion by reference here.

Section 111(a)(6) of the CAA defines an ''existing source'' as ''any stationary source other than a new source.'' Therefore, the emission guidelines do not apply to any steam generating units that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT. Moreover, because the EPA is now finalizing revised standards of performance for coal-fired steam generating units that undertake a modification, a modified coal-fired steam generating unit would be considered ''new,'' and therefore not subject to these emission guidelines, if the modification occurs after the date the proposal was published in the **Federal Register** (May 23, 2023). Any coal-fired steam generating unit that has modified prior to that date would be considered an existing source that is subject to these emission guidelines.

In addition, the EPA is finalizing in the applicability requirements of the emission guidelines many of the same exemptions as discussed for 40 CFR part 60, subpart TTTT, in section VIII.E.1 of this preamble. EGUs that may be excluded from the requirement to establish standards under a state plan are: (1) units that are subject to 40 CFR part 60, subpart TTTT, as a result of commencing a qualifying modification or reconstruction; (2) steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh; (3) non-fossil fuel units (*i.e.*, units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) combined heat and power (CHP) units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater; (5) units that serve a generator along with other affected EGU(s), where the effective generation capacity (determined based on a prorated output of the base load rating of EGU) is 25 MW or less; (6) municipal waste combustor units subject to 40 CFR part 60, subpart Eb; (7) commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; (8) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU; or (9) coal-fired steam generating units that have elected to permanently cease operation prior to January 1, 2032.

The exemptions listed above at (4), (5), (6), and (7) are among the current exemptions at 40 CFR 60.5509(b), as discussed in section VIII.E.1 of this preamble. The exemptions listed above at (2), (3), and (8) are exemptions the EPA is finalizing revisions for 40 CFR part 60, subpart TTTT, and the rationale for the exemptions is in section VIII.E.1 of this preamble. For consistency with the applicability requirements in 40 CFR part 60, subpart TTTT, and 40 CFR part 60, subpart TTTTa, the Agency is finalizing these same exemptions for the applicability of the emission guidelines.

2. Coal-Fired Units Permanently Ceasing Operation Before January 1, 2032

The EPA is not addressing existing coal-fired steam generating units demonstrating that they plan to permanently cease operating before January 1, 2032, in these emission guidelines. Sources ceasing operation before that date have far less emission reduction potential than sources that will be operating longer, because there are unlikely to be appreciable, cost-reasonable emission reductions available on average for the group of sources operating in that timeframe. This is because controls that entail capital expenditures are unlikely to be

[267] The term ''designated facility'' means ''any existing facility . . . which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility.'' See 40 CFR 60.21a(b).

[268] Under CAA section 111, the determination of whether a source is a new source or an existing source (and thus potentially a designated facility) is based on the date that the EPA proposes to establish standards of performance for new sources.

[269] The EPA recognizes, however, that the word ''facility'' is often understood colloquially to refer to a single power plant, which may have one or more EGUs co-located within the plant's boundaries.

of reasonable cost for these sources due to the relatively short period over which they could amortize the capital costs of controls.

In particular, in developing the emission guidelines, the EPA evaluated two systems of emission reduction that achieve substantial emission reductions for coal-fired steam generating units: CCS with 90 percent capture; and natural gas co-firing at 40 percent of heat input. For CCS, the EPA has determined that controls can be installed and fully operational by the compliance date of January 1, 2032, as detailed in section VII.C.1.a.i(E) of this preamble. CCS would therefore, in most cases, be unavailable to coal-fired steam generating units planning to cease operation prior to that date. Furthermore, the EPA evaluated the costs of CCS for different amortization periods. For an amortization period of more than 7 years—such that sources operate after January 1, 2039—annualized fleet average costs are comparable to or less than the costs of controls the EPA has previously determined to be reasonable ($18.50/MWh of generation and $98/ton of CO_2 reduced), as detailed in section VII.C.1.a.ii of this preamble. However, the costs for shorter amortization periods are higher. For sources ceasing operation by January 1, 2032, it would be unlikely that the annualized costs of CCS would be reasonable even were CCS installed at an earlier date (*e.g.*, by January 1, 2030) due to the shorter amortization period available.

Because the costs of CCS would be higher for shorter amortization periods, the EPA is finalizing a separate subcategory for sources demonstrating that they plan to permanently cease operating by January 1, 2039, with a BSER of 40 percent natural gas co-firing, as detailed in section VII.C.2.b.ii of this preamble. For natural gas co-firing, the EPA is finalizing a compliance date of January 1, 2030, as detailed in section VII.C.2.b.i(C) of this preamble. Therefore, the EPA assumes sources subject to a natural gas co-firing BSER can amortize costs for a period of up to 9 years. The EPA has determined that the costs of natural gas co-firing at 40 percent meet the metrics for cost reasonableness for the majority of the capacity that operate more than 2 years after the January 1, 2030, implementation date, *i.e.*, that operate after January 1, 2032 (and up to December 31, 2038), and that therefore have an amortization period of more than 2 years (and up to 9 years).

However, for sources ceasing operation prior to January 1, 2032, the EPA believes that establishing a best system of emission reduction corresponding to a substantial level of natural gas co-firing would broadly entail costs of control that are above those that the EPA is generally considering reasonable. Sources permanently ceasing operation before January 1, 2032 would have less than 2 years to amortize the capital costs, as detailed in section VII.C.2.a of this preamble. Compared to the metrics for cost reasonableness that EPA has previously deemed reasonable ($18.50/MWh of generation and $98/ton of CO_2 reduced), very few sources can co-fire 40 percent natural gas at costs comparable to these metrics with an amortization period of only one year; only 1 percent of units have costs that are below both $18.50/MWh of generation and $98/ton of CO_2 reduced. The number of sources that can co-fire lower amounts of natural gas at costs comparable to these metrics is likewise limited—only approximately 34 percent of units can co-fire with 20 percent natural gas at costs lower than both cost metrics. Furthermore, the period that these sources would operate with co-firing for would be short, so that the emission reductions from that group of sources would be limited.

By contrast, assuming a two-year amortization period, many more units can co-fire with meaningful amounts of natural gas at a cost that is consistent with the metrics EPA has previously used: 18 percent of units can co-fire with 40 percent natural gas at costs less than $98/ton and $18.50/MWh, and 50 percent of units can co-fire with 20 percent natural gas at costs lower than both metrics. Because a substantial number of sources can implement 40-percent co-firing with natural gas with an amortization period of two years or longer with reasonable costs, and even more can co-fire with lesser amounts with reasonable costs with amortization periods longer than two years,[270] the EPA determined that a technology-based BSER was available for coal-fired units operating past January 1, 2032.

Sources that retire before that date, however, are differently situated as described above. In light of the small number of sources that are planning to retire before January 1, 2032 that could cost-effectively co-fire with natural gas, coupled with the small amount of emissions reductions that can be achieved from co-firing in such a short time span, the EPA is choosing not to establish a BSER for these sources.[271]

Because, at this time, the EPA has determined that CCS and natural gas co-firing are not available at reasonable cost for sources ceasing operation before January 1, 2032, the EPA is not finalizing a BSER for such sources. Not finalizing a BSER for these sources is consistent with the Agency's discretion to take incremental steps to address CO_2 from sources in the category, and to direct the EPA's limited resources at regulation of those sources that can achieve the most emission reductions. The EPA is therefore providing that existing coal-fired steam generating EGUs that have elected to cease operating before January 1, 2032, are not regulated by these emission guidelines. This exemption applies to a source until the earlier of December 31, 2031, or the date it demonstrates in the state plan that it plans to cease operation. If a source continues to operate past this date, it is no longer exempt from these emission guidelines. See section X.E.1 of this preamble for discussion of how state plans should address sources subject to exemption (9).[272]

3. Sources Outside of the Contiguous U.S.

The EPA proposed the same emission guidelines for fossil fuel-fired steam

[270] As described in detail in section X.C.2 of this preamble, the EPA recognizes that particular affected EGUs may have characteristics that make it unreasonable to achieve the degree of emission limitation corresponding to 40 percent co-firing with natural gas. For example, a state may be able to demonstrate a fundamental difference between the costs the EPA considered in these emission guidelines and the costs to an affected EGU that plans to cease operation in late 2032. If such costs make it unreasonable for a particular unit to meet the degree of emission limitation corresponding to 40 percent co-firing with natural gas, the state may apply a less stringent standard of performance to that unit. Consistent with the requirements for calculating a less stringent standard of performance at 40 CFR 60.24a(f), under these emission guidelines states would consider whether it is reasonable for units that cannot cost-reasonably co-fire natural gas at 40 percent to co-fire at levels lower than 40 percent. It is thus appropriate that coal-fired EGUs that can reasonably co-fire any amount of natural gas be subject to these emission guidelines.

[271] For the reasons described at length in section VI.B, the EPA does not believe that heat rate improvement measures or HRI are appropriate for sources retiring before January 1, 2032 because HRI applied to coal-fired sources achieve few emission reductions, and can lead to the "rebound effect" where CO_2 emissions from the source increase rather than decrease as a consequence of imposing the technologies.

[272] The EPA notes that this applicability exemption does not conflict with states' ability to consider the remaining useful lives of "particular" sources that are subject to these emission guidelines. 42 U.S.C. 7411(d)(1). As the EPA's implementing regulations specify, the provision for states' consideration of RULOF is intended address the specific conditions of particular sources, whereas the EPA is responsible for determining generally how to regulate a source category under an emission guideline. Moreover, RULOF applies only to when a state is applying a standard of performance to an affected source—and the state would not apply a standard of performance to exempted sources.

generating units in non-continental areas (*i.e.*, Hawaii, the U.S. Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) and non-contiguous areas (non-continental areas and Alaska) as the EPA proposed for comparable units in the contiguous 48 states. The EPA notes that the modeling that supports the final emission guidelines focus on sources in the contiguous U.S. Further, the EPA notes that few, if any, coal-fired steam generating units operate outside of the contiguous 48 states and meet the applicability criteria. Finally, the EPA notes that the proposed BSER and degree of emissions limitation for non-continental oil-fired steam generating units would have achieved few emission reductions. Therefore, the EPA is not finalizing emission guidelines for existing steam generating units in states and territories (including Alaska, Hawaii, Guam, Puerto Rico, and the U.S. Virgin Islands) that are outside of the contiguous U.S. at this time.

4. IGCC Units

The EPA notes that existing IGCC units were included in the proposed applicability requirements and that, in section VII.B of this preamble, the EPA is finalizing inclusion of those units in the subcategory of coal-fired steam generating units. IGCC units gasify coal or solid fossil fuel (*e.g.*, pet coke) to produce syngas (a mixture of carbon monoxide and hydrogen), and either burn the syngas directly in a combined cycle unit or use a catalyst for water-gas shift (WGS) to produce a pre-combustion gas stream with a higher concentration of CO_2 and hydrogen, which can be burned in a hydrogen turbine combined cycle unit. As described in section VII.C of this preamble, the final BSER for coal-fired steam generating units includes co-firing natural gas and CCS. The few IGCC units that now operate in the U.S. either burn natural gas exclusively—and as such operate as natural gas combined cycle units—or in amounts near to the 40 percent level of the natural gas co-firing BSER. Additionally, IGCC units may be suitable for pre-combustion CO_2 capture. Because the CO_2 concentration in the pre-combustion gas, after WGS, is high relative to coal-combustion flue gas, pre-combustion CO_2 capture for IGCC units can be performed using either an amine-based (or other solvent-based) capture process or a physical absorption capture process. Alternatively, post-combustion CO_2 capture can be applied to the source. The one existing IGCC unit that still uses coal was recently awarded funding from DOE for a front-end engineering design (FEED) study for CCS targeting a capture efficiency of more than 95 percent.[273] For these reasons, the EPA is not distinguishing IGCC units from other coal-fired steam generating EGUs, so that the BSER of co-firing for medium-term coal-fired units and CCS for long-term coal-fired units apply to IGCC units.[274]

5. Fossil Fuel-Type Definitions for Subcategories of Steam Generating Units

In this action, the EPA is finalizing definitions for subcategories of existing fossil fuel-fired steam generating units based on the type and amount of fossil fuel used in the unit. The EPA is finalizing separate subcategories based on fuel type because the carbon content of the fuel combusted affects the output emission rate (*i.e.*, lb CO_2/MWh). Fuels with a higher carbon content produce a greater amount of CO_2 emissions per unit of fuel combusted (on a heat input basis, MMBtu) and per unit of electricity generated (*i.e.*, MWh).

The EPA proposed fossil fuel type subcategory definitions based on the definitions in 40 CFR part 63, subpart UUUUU, and the fossil fuel definitions in 40 CFR part 60, subpart TTTT. Those proposed definitions were determined by the relative heat input contribution of the different fuels combusted in a unit during the 3 years prior to the proposed compliance date of January 1, 2030. Further, to be considered an oil-fired or natural gas-fired unit for purposes of this emission guideline, a source would no longer retain the capability to fire coal after December 31, 2029.

The EPA proposed a 3-year lookback period, so that the proposed fuel-type subcategorization would have been based, in part, on the fuel type fired between January 1, 2027, and January 1, 2030. However, the intent of the proposed fuel type subcategorization was to base the fuel type definition on the state of the source on January 1, 2030. Therefore, the EPA is finalizing the following fuel type subcategory definitions:

- A *coal-fired steam generating unit* is an electric utility steam generating unit or IGCC unit that meets the definition of ''fossil fuel-fired'' and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029, or that retains the capability to fire coal after December 31, 2029.
- An *oil-fired steam generating unit* is an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns oil for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.
- A *natural gas-fired steam generating unit* is an electric utility steam generating unit meeting the definition of ''fossil fuel-fired,'' that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.

The EPA received some comments on the fuel type definitions. Those comments and responses are as follows.

Comment: Some industry stakeholders suggested changes to the proposed definitions for fossil fuel type. Specifically, some commenters requested that the reference to the initial compliance date be removed and that the fuel type determination should instead be rolling and continually update after the initial compliance date. Those commenters suggested this would, for example, allow sources in the coal-fired subcategory that begin natural gas co-firing in 2030 to convert to the natural-gas fired subcategory prior to the proposed date of January 1, 2040, instead of ceasing operation.

Other industry commenters suggested that to be a natural gas-fired steam generating unit, a source could either meet the heat input requirements during the 3 years prior to the compliance date *or* (emphasis added) no longer retain the capability to fire coal after December 31, 2029. Those commenters noted that, as proposed, a source that had planned to convert to 100 percent natural gas-firing would essentially have to do so prior to January 1, 2027, to meet the proposed heat input-based definition, in addition to removing the capability to fire coal by the compliance date.

[273] Duke Edwardsport DOE FEED Study Fact Sheet. *https://www.energy.gov/sites/default/files/2024-01/OCED_CCFEEDs_AwardeeFactSheet_Duke_1.5.2024.pdf.*

[274] For additional details on pre-combustion CO_2 capture, please see the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

Response: Although full natural gas conversions are not a measure that the EPA considered as a potential BSER, the emission guidelines do not prohibit such conversions should a state elect to require or accommodate them. As noted above, the EPA recognizes that many steam EGUs that formerly utilized coal as a primary fuel have fully or partially converted to natural gas, and that additional steam EGUs may elect to do so during the implementation period for these emission guidelines. However, these emission guidelines place reasonable constraints on the timing of such a conversion in situations where a source seeks to be regulated as a natural gas-fired steam EGU rather than as a coal-fired steam EGU. The EPA believes that such constraints are necessary in order to avoid creating a perverse incentive for EGUs to defer conversions in a way that could undermine the emission reduction purpose of the rule. Therefore, the EPA disagrees with those commenters that suggest the EPA should, in general, allow EGUs to be regulated as natural gas-fired steam EGUs when they undertake such conversions past January 1, 2030.

However, the EPA acknowledges that the proposed subcategorization would have essentially required a unit to convert to natural gas by January 1, 2027 in order to be regulated as a natural gas-fired steam EGU. The EPA is finalizing fuel type subcategorization based on the state of the source on the compliance date of January 1, 2030, and during any period thereafter, as detailed in section VII.B of this preamble. Should a source not be able to fully convert to natural gas by this date, it would be treated as a coal-fired steam generating EGU; however, the state may be able to use the RULOF provisions, as discussed in section X.C.2 of this preamble, to particularize a standard of performance for the unit. Note that if a state relies on operating conditions within the control of the source as the basis of providing a less stringent standard of performance or longer compliance schedule, it must include those operating conditions as an enforceable requirement in the state plan. 40 CFR 60.24a(g).

C. Rationale for the BSER for Coal-Fired Steam Generating Units

This section of the preamble describes the rationale for the final BSERs for existing coal-fired steam generating units based on the criteria described in section V.C of this preamble.

At proposal, the EPA evaluated two primary control technologies as potentially representing the BSER for existing coal-fired steam generating units: CCS and natural gas co-firing. For sources operating in the long-term, the EPA proposed CCS with 90 percent capture as BSER. For sources operating in the medium-term (*i.e.*, those demonstrating that they plan to permanently cease operation by January 1, 2040), the EPA proposed 40 percent natural gas co-firing as BSER. For imminent-term and near-term sources ceasing operation earlier, the EPA proposed BSERs of routine methods of operation and maintenance.

The EPA is finalizing CCS with 90 percent capture as BSER for coal-fired steam generating units because CCS can achieve a substantial amount of emission reductions and satisfies the other BSER criteria. CCS has been adequately demonstrated and results in by far the largest emissions reductions of the available control technologies. As noted below, the EPA has also determined that the compliance date for CCS is January 1, 2032. CCS, however, entails significant up-front capital expenditures that are amortized over a period of years. The EPA evaluated the cost for different amortization periods, and the EPA has concluded that CCS is cost-reasonable for units that operate past January 1, 2039. As noted in section IV.D.3.b of this preamble, about half (87 GW out of 181 GW) of all coal-fired capacity currently in existence has announced plans to permanently cease operations by January 1, 2039, and additional sources are likely to do so because they will be older than the age at which sources generally have permanently ceased operations since 2000. The EPA has determined that the remaining sources that may operate after January 1, 2039, can, on average, install CCS at a cost that is consistent with the EPA's metrics for cost reasonableness, accounting for an amortization period for the capital costs of more than 7 years, as detailed in section VII.C.1.a.ii of this preamble. If a particular source has costs of CCS that are fundamentally different from those amounts, the state may consider it to be a candidate for a different control requirement under the RULOF provision, as detailed in section X.C.2 of this preamble. For the group of sources that permanently cease operation before January 1, 2039, the EPA has concluded that CCS would in general be of higher cost, and therefore is finalizing a subcategory for these units, termed medium-term units, and finalizing 40 percent natural gas co-firing on a heat input basis as the BSER.

These final subcategories and BSERs are largely consistent with the proposal, which included a long-term subcategory for sources that did not plan to permanently cease operations by January 1, 2040, with 90 percent capture CCS as the BSER; and a medium-term subcategory for sources that permanently cease operations by that date and were not in any of the other proposed subcategories, discussed next, with 40 percent co-firing as the BSER. For both subcategories, the compliance date was January 1, 2030. The EPA also proposed an imminent-term subcategory, for sources that planned to permanently cease operations by January 1, 2032; and a near-term subcategory, for sources that planned to permanently case operations by January 1, 2035, and that limited their annual capacity utilization to 20 percent. The EPA proposed a BSER of routine methods of operation and maintenance for these two subcategories.

The EPA is not finalizing these imminent-term and near-term subcategories. In addition, after considering the comments, the EPA acknowledges that some additional time from what was proposed may be beneficial for the planning and installation of CCS. Therefore, the EPA is finalizing a January 1, 2032, compliance date for long-term existing coal-fired steam generating units. As noted above, the EPA's analysis of the costs of CCS also indicates that CCS is cost-reasonable with a minimum amortization period of seven years; as a result, the final emission guidelines would apply a CCS-based standard only to those units that plan to operate for at least seven years after the compliance deadline (*i.e.*, units that plan to remain in operation after January 1, 2039). For medium-term sources subject to a natural gas co-firing BSER, the EPA is finalizing a January 1, 2030, compliance date because the EPA has concluded that this provides a reasonable amount of time to begin co-firing, a technology that entails substantially less up-front infrastructure and, relatedly, capital expenditure than CCS.

1. Long-Term Coal-Fired Steam Generating Units

The EPA is finalizing CCS with 90 percent capture of CO_2 at the stack as BSER for long-term coal-fired steam generating units. Coal-fired steam generating units are the largest stationary source of CO_2 in the United States. Coal-fired steam generating units have higher emission rates than other generating technologies, about twice the emission rate of a natural gas combined cycle unit. Typically, even newer, more efficient coal-fired steam generating units emit over 1,800 lb CO_2/MWh-gross, while many existing coal-fired steam generating units have emission rates of 2,200 lb CO_2/MWh-gross or higher. As noted in section IV.B of this preamble, coal-fired sources emitted 909 MMT CO_2e in 2021, 59 percent of the GHG emissions from the power sector and 14 percent of the total U.S. GHG emissions—contributing more to U.S. GHG emissions than any other sector, aside from transportation road sources.[275] Furthermore, considering the sources in the long-term subcategory will operate longer than sources with shorter operating horizons, long-term coal-fired units have the potential to emit more total CO_2.

CCS is a control technology that can be applied at the stack of a steam generating unit, achieves substantial reductions in emissions and can capture and permanently sequester more than 90 percent of CO_2 emitted by coal-fired steam generating units. The technology is adequately demonstrated, given that it has been operated at scale and is widely applicable to these sources, and there are vast sequestration opportunities across the continental U.S. Additionally, the costs for CCS are reasonable, in light of recent technology cost declines and policies including the tax credit under IRC section 45Q. Moreover, the non-air quality health and environmental impacts of CCS can be mitigated and the energy requirements of CCS are not unreasonably adverse. The EPA's weighing of these factors together provides the basis for finalizing CCS as BSER for these sources. In addition, this BSER determination aligns with the caselaw, discussed in section V.C.2.h of the preamble, stating that CAA section 111 encourages continued advancement in pollution control technology.

At proposal, the EPA also evaluated natural gas co-firing at 40 percent of heat input as a potential BSER for long-term coal-fired steam generating units. While the unit level emission rate reductions of 16 percent achieved by 40 percent natural gas co-firing are appreciable, those reductions are substantially less than CCS with 90 percent capture of CO_2. Therefore, because CCS achieves more reductions at the unit level and is cost-reasonable, the EPA is not finalizing natural gas co-firing as the BSER for these units. Further, the EPA is not finalizing partial-CCS at lower capture rates (*e.g.*, 30 percent) because it achieves substantially fewer unit-level reductions at greater cost, and because CCS at 90 percent is achievable. Notably, the IRC section 45Q tax credit may not be available to defray the costs of partial CCS and the emission reductions would be limited. And the EPA is not finalizing HRI as the BSER for these units because of the limited reductions and potential rebound effect.

a. Rationale for CCS as the BSER for Long-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA explains the rationale for CCS as the BSER for existing long-term coal-fired steam generating units. This section discusses the aspects of CCS that are relevant for existing coal-fired steam generating units and, in particular, long-term units. As noted in section VIII.F.4.c.iv of this preamble, much of this discussion is also relevant for the EPA's determination that CCS is the BSER for new base load combustion turbines.

In general, CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Detailed descriptions of these components are provided in section VII.C.1.a.i of this preamble. As an overview, post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system, such as a utility boiler or combustion turbine. This technology is referred to as ''post-combustion capture'' because CO_2 is a product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. The exhaust gases from most combustion processes are at atmospheric pressure, contain somewhat dilute concentrations of CO_2, and are moved through the flue gas duct system by fans. To separate the CO_2 contained in the flue gas, most current post-combustion capture systems utilize liquid solvents—commonly amine-based solvents—in CO_2 scrubber systems using chemical absorption (or chemisorption).[276] In a chemisorption-based separation process, the flue gas is processed through the CO_2 scrubber and the CO_2 is absorbed by the liquid solvent. The CO_2-rich solvent is then regenerated by heating the solvent to release the captured CO_2.

The high purity CO_2 is then compressed and transported, generally through pipelines, to a site for geologic sequestration (*i.e.*, the long-term containment of CO_2 in subsurface geologic formations). Pipelines are subject to Federal safety regulations administered by PHMSA. Furthermore, sequestration sites are widely available across the nation, and the EPA has developed a comprehensive regulatory structure to oversee geologic sequestration projects and assure their safety and effectiveness.[277]

i. Adequately Demonstrated

In this section of the preamble, the EPA explains the rationale for finalizing its determination that 90 percent capture applied to long-term coal-fired steam generating units is adequately demonstrated. In this section, the EPA first describes how simultaneous operation of all components of CCS functioning in concert with one another has been demonstrated, including a commercial scale application on a coal-fired steam generating unit. The demonstration of the individual components of CO_2 capture, transport, and sequestration further support that CCS is adequately demonstrated. The EPA describes how demonstrations of CO_2 capture support that 90 percent capture rates are adequately demonstrated. The EPA further describes how transport and geologic sequestration are adequately demonstrated, including the feasibility of transport infrastructure and the broad availability of geologic sequestration reservoirs in the U.S.

(A) Simultaneous Demonstration of CO_2 Capture, Transport, and Sequestration

The EPA proposed that CCS was adequately demonstrated for applications on combustion turbines and existing coal-fired steam generating units.

On reviewing the available information, all components of CCS—CO_2 capture, CO_2 transport, and CO_2 sequestration—have been demonstrated concurrently, with each component operating simultaneously and in concert with the other components.

(1) Industrial Applications of CCS

Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s[278] and has been used in a variety of industrial applications for decades. For example, since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant at Searles Valley Minerals (Trona,

[275] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. U.S. Greenhouse Gas Emissions by Inventory Sector, 2021. https://cfpub.epa.gov/ghgdata/inventoryexplorer/index.html#iallsectors/allsectors/allgas/inventsect/current.*

[276] Other technologies may be used to capture CO_2, as described in the final TSDs, *GHG Mitigation Measures for Steam Generating Units* and the *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines*, available in the rulemaking docket.

[277] 80 FR 64549 (October 23, 2015).

[278] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

California).[279] Furthermore, thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[280] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with EOR.[281] There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under construction or in advanced stages of development.[282] This broad application of CCS demonstrates that the components of CCS have been successfully operated simultaneously. The Shute Creek Facility has a capture capacity of 7 million metric tons per year and has been in operation since 1986.[283] The facility uses a solvent-based process to remove CO_2 from natural gas, and the captured CO_2 is stored in association with EOR. Another example of CCS in industrial applications is the Great Plains Synfuels Plant has a capture capacity of 3 million metric tons per year and has been in operation since 2000.[284 285] The Great Plains Synfuels Plant (Beulah, North Dakota) uses a solvent-based process to remove CO_2 from lignite-derived syngas, the CO_2 is transported by the Souris Valley pipeline, and stored underground in association with EOR in the Weyburn and Midale Oil Units in Saskatchewan, Canada. Over 39 million metric tons of CO_2 has been captured since 2000.

(2) Various CO_2 capture methods are used in industrial applications and are tailored to the flue gas conditions of a particular industry (see the TSD *GHG Mitigation Measures for Steam Generating Units* for details). Of those capture technologies, amine solvent-based capture has been demonstrated for removal of CO_2 from the post-combustion flue gas of fossil fuel-fired EGUs. The Quest CO_2 capture facility in Alberta, Canada, uses amine-based CO_2 capture retrofitted to three existing steam methane reformers at the Scotford Upgrader facility (operated by Shell Canada Energy) to capture and sequester approximately 80 percent of the CO_2 in the produced syngas.[286] Amine-solvents are also applied for post-combustion capture from fossil fuel fired EGUs. The Quest facility has been operating since 2015 and captures approximately 1 million metric tons of CO_2 per year.

Applications of CCS at Coal-Fired Steam Generating Units

For electricity generation applications, this includes operation of CCS at Boundary Dam Unit 3 in Saskatchewan, Canada. CCS at Boundary Dam Unit 3 includes capture of the CO_2 from the flue-gas of the fossil fuel-fired EGU, compression of the CO_2 onsite and transport via pipeline offsite, and storage of the captured CO_2 underground. Storage of the CO_2 captured at Boundary Dam primarily occurs via EOR. Moreover, CO_2 captured from Boundary Dam Unit 3 is also stored in a deep saline aquifer at the Aquistore Deep Saline CO_2 Storage Project, which has permanently stored over 550,000 tons of CO_2 to date.[287] Other demonstrations of CCS include the 240 MWe Petra Nova CCS project at the subbituminous coal-fired W.A. Parish plant in Texas, which, because it was EPAct05-assisted, we cite as useful in section VII.C.1.a.i(B)(2) of this preamble, but not essential, corroboration. See section VII.C.1.a.i(H)(1) for a detailed description of how the EPA considers information from EPAct05-assisted projects.

Commenters stated that that all constituent components of CCS—carbon capture, transportation, and sequestration—have not been adequately demonstrated in integrated, simultaneous operation. We disagree with this comment. The record described in the preceding shows that all components have been demonstrated simultaneously. Even if the record only included demonstration of the individual components of CCS, the EPA would still determine that CCS is adequately demonstrated as it would be reasonable on a technical basis that the individual components are capable of functioning together—they have been engineered and designed to do so, and the record for the demonstration of the individual components is based on decades of direct data and experience.

(B) CO_2 Capture Technology at Coal-Fired Steam Generating Units

The EPA is finalizing the determination that the CO_2 capture component of CCS has been adequately demonstrated at a capture efficiency of 90 percent, is technically feasible, and is achievable over long periods (*e.g.*, a year) for the reasons summarized here and detailed in the following subsections of this preamble. This determination is based, in part, on the demonstration of the technology at existing coal-fired steam generating units, including the commercial-scale installation at Boundary Dam Unit 3. The application of CCS at Boundary Dam follows decades of development of CO_2 capture for coal-fired steam generating units, as well as numerous smaller-scale demonstrations that have successfully implemented this technology. Review of the available information has also identified specific, currently available, minor technological improvements that can be applied today to better the performance of new capture plant retrofits, and which can assure that the capture plants achieve 90 percent capture. The EPA's determination that 90 percent capture of CO_2 is adequately demonstrated is further corroborated by EPAct05-assisted projects, including the Petra Nova project.

Moreover, several CCS retrofit projects on coal-fired steam generating units are in progress that apply the lessons from the prior projects and use solvents that achieve higher capture rates. Technology providers that supply those solvents and the associated process technologies have made statements concluding that the technology is commercially proven and available today and have further stated that those solvents achieve capture rates of 95 percent or greater. Technology providers have decades of experience and have done the work to responsibly scale up the technology over that time across a range of flue gas compositions. Taking all of those factors into consideration, and accounting for the operation and flue gas conditions of the affected sources, solvent-based capture will consistently achieve capture rates of 90 percent or greater for the fleet of long-term coal-fired steam generating units.

Various technologies may be used to capture CO_2, the details of which are described generally in section IV.C.1 of this preamble and in more detail in the final TSD, *GHG Mitigation Measures for Steam Generating Units*, which is

[279] Dooley, J.J., *et al.* (2009). "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[280] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, "Hazardous Annual Liquid Data." 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[281] GHGRP US EPA. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[282] Carbon Capture and Storage in the United States. CBO. December 13, 2023. *https://www.cbo.gov/publication/59345.*

[283] *Id.*

[284] *https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/great-plains.*

[285] *https://co2re.co/FacilityData.*

[286] Quest Carbon Capture and Storage Project Annual Summary Report, Alberta Department of Energy: 2021. *https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2021.*

[287] Aquistore Project. *https://ptrc.ca/media/whats-new/aquistore-co2-storage-project-reached-+500000-tonnes-stored.*

available in the rulemaking docket.[288] For post-combustion capture, these technologies include solvent-based methods (*e.g.*, amines, chilled ammonia), solid sorbent-based methods, membrane filtration, pressure-swing adsorption, and cryogenic methods.[289] Lastly, oxy-combustion uses a purified oxygen stream from an air separation unit (often diluted with recycled CO_2 to control the flame temperature) to combust the fuel and produce a higher concentration of CO_2 in the flue gas, as opposed to combustion with oxygen in air which contains 80 percent nitrogen. The CO_2 can then be separated by the aforementioned CO_2 capture methods. Of the available capture technologies, solvent-based processes have been the most widely demonstrated at commercial scale for post-combustion capture and are applicable to use with either combustion turbines or steam generating units.

The EPA's identification of CCS with 90 percent capture as the BSER is premised, in part, on an amine solvent-based CO_2 system. Amine solvents used for carbon capture are typically proprietary, although non-proprietary solvents (*e.g.*, monoethanolamine, MEA) may be used. Carbon capture occurs by reactive absorption of the CO_2 from the flue gas into the amine solution in an absorption column. The amine reacts with the CO_2 but will also react with impurities in the flue gas, including SO_2. PM will also affect the capture system. Adequate removal of SO_2 and PM prior to the CO_2 capture system is therefore necessary. After pretreatment of the flue gas with conventional SO_2 and PM controls, the flue gas goes through a quencher to cool the flue gas and remove further impurities before the CO_2 absorption column. After absorption, the CO_2-rich amine solution passes to the solvent regeneration column, while the treated gas passes through a water and/or acid wash column to limit emission of amines or other byproducts. In the solvent regeneration column, the solution is heated (using steam) to release the absorbed CO_2. The released CO_2 is then compressed and transported offsite, usually by pipeline. The amine solution from the regenerating column is then cooled, a portion of the lean solvent is treated in a solvent reclaiming process to mitigate degradation of the solvent, and the lean solvent streams are recombined and sent back to the absorption column.

(1) Capture Demonstrations at Coal-Fired Steam Generating Units

(a) SaskPower's Boundary Dam Unit 3

SaskPower's Boundary Dam Unit 3, a 110 MW lignite-fired unit in Saskatchewan, Canada, was designed to achieve CO_2 capture rates of 90 percent using an amine-based post-combustion capture system retrofitted to the existing steam generating unit. The capture plant, which began operation in 2014, is the first full-scale CO_2 capture system retrofit on an existing coal-fired power plant. It uses the amine-based Shell CANSOLV® process, which includes an amine-based SO_2 scrubbing process and a separate amine-based CO_2 capture process, with integrated heat and power from the steam generating unit.[290]

After undergoing maintenance and design improvements in September and October of 2015 to address technical and mechanical challenges faced in its first year of operation, Boundary Dam Unit 3 completed a 72-hour test of its design capture rate (3,240 metric tons/day), and captured 9,695 metric tons of CO_2 or 99.7 percent of the design capacity (approximately 89.7 percent capture) with a peak rate of 3,341 metric tons/day.[291] However, the capture plant has not consistently operated at this total capture efficiency. In general, the capture plant ran less than 100 percent of the flue gas through the capture equipment and the coal-fired steam generating unit also operates when the capture plant is offline for maintenance. As a result, although the capture plant has consistently achieved 90 percent capture rates of the CO_2 in the processed slipstream, the amount of CO_2 captured was less than 90 percent of the total amount of CO_2 in the flue gas of the steam generating unit. Some of the reasons for this operation were due to the economic incentives and regulatory requirements of the project, while other reasons were due to technical challenges. The EPA has reviewed the record of CO_2 capture at Boundary Dam Unit 3. While Boundary Dam is in Canada and therefore not subject to this action, these technical challenges have been sufficiently overcome or are actively mitigated so that Boundary Dam has more recently been capable of achieving capture rates of 83 percent when the capture plant is online.[292] Furthermore, the improvements already employed and identified at Boundary Dam can be readily applied during the initial construction of a new CO_2 capture plant today.

The CO_2 captured at Boundary Dam is mostly used for EOR and CO_2 is also stored geologically in a deep saline reservoir at the Aquistore site.[293] The amount of flue gas captured is based in part on economic reasons (*i.e.*, to meet related contract requirements). The incentives for CO_2 capture at Boundary Dam beyond revenue from EOR have been limited to date, and there have been limited regulatory requirements for CO_2 capture at the facility. As a result, a portion (about 25 percent on average) of the flue gas bypasses the capture plant and is emitted untreated. However, because of increasing requirements to capture CO_2 in Canada, Boundary Dam Unit 3 has more recently pursued further process optimization.

Total capture efficiencies at the plant have also been affected by technical issues, particularly with the SO_2 removal system that is upstream of the CO_2 capture system. Operation of the SO_2 removal system affects downstream CO_2 capture and the amount of flue gas that can be processed. Specifically, fly ash (PM) in the flue gas at Boundary Dam Unit 3 contributed to fouling of SO_2 system components, particularly in the SO_2 reboiler and the demisters of the SO_2 absorber column. Buildup of scale in the SO_2 reboiler limited heat transfer and regeneration of the SO_2 scrubbing amine, and high pressure drop affected the flowrate of the SO_2 lean-solvent back to the SO_2 absorber. Likewise, fouling of the demisters in the SO_2 absorber column caused high pressure drop and restricted the flow of flue gas through the system, limiting the amount of flue gas that could be processed by the downstream CO_2 capture system. To address these technical issues, additional wash systems were added, including "demister wash systems, a pre-scrubber flue gas inlet curtain spray wash system, flue gas cooler throat sprays, and a booster fan wash system." [294]

[288] Technologies to capture CO_2 are also discussed in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines.*

[289] For pre-combustion capture (as is applicable to an IGCC unit), syngas produced by gasification passes through a water-gas shift catalyst to produce a gas stream with a higher concentration of hydrogen and CO_2. The higher CO_2 concentration relative to conventional combustion flue gas reduces the demands (power, heating, and cooling) of the subsequent CO_2 capture process (*e.g.*, solid sorbent-based or solvent-based capture); the treated hydrogen can then be combusted in the unit.

[290] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820191.*

[291] SaskPower Annual Report (2015–16). *https://www.saskpower.com/about-us/Our-Company/~/link.aspx?_id=29E795C8C20D48398EAB5E3273C256AD&_z=z.*

[293] Aquistore. *https://ptrc.ca/aquistore.*

[294] *Id.*

Such issues will definitively not occur in a different type of SO_2 removal system (*e.g.*, wet lime scrubber flue gas desulfurization, wet-FGD). SO_2 scrubbers have been successfully operated for decades across a large number of U.S. coal-fired sources. Of the coal-fired sources with planned operation after 2039, 60 percent have wet FGD and 23 percent have a dry FGD. In section VII.C.1.a.ii of this preamble, the EPA accounts for the cost of adding a wet-FGD for those sources that do not have an FGD.

To further mitigate fouling due to fly ash, the PM controls (electrostatic precipitators) at Boundary Dam Unit 3 were upgraded in 2015/2016 by adding switch integrated rectifiers. Of the coal-fired sources with planned operation after 2039, 31 percent have baghouses and 67 percent have electrostatic precipitators. Sources with baghouses have greater or more consistent degrees of emission control, and wet FGD also provides additional PM control.

Fouling at Boundary Dam Unit 3 also affected the heat exchangers in both the SO_2 removal system and the CO_2 capture system. Additional redundancies and isolations to those key components were added in 2017 to allow for online maintenance. Damage to the capture plant's CO_2 compressor resulted in an unplanned outage in 2021, and the issue was corrected.[295] The facility reported 98.3 percent capture system availability in the third quarter of 2023.[296]

Regular maintenance further mitigates fouling in the SO_2 and CO_2 absorbers, and other challenges (*e.g.*, foaming, biological fouling) typical of gas-liquid absorbers can be mitigated by standard procedures. According to the 2022 paper co-authored by the International CCS Knowledge Centre and SaskPower, ''[a] number of initiatives are ongoing or planned with the goal of eliminating flue gas bypass as follows: Since 2016, online cleaning of demisters has been effective at controlling demister pressure; Chemical cleans and replacement of fouled packing in the absorber towers to reduce pressure losses; Optimization of antifoam injection and other aspects of amine health, to minimize foaming potential; [and] Optimization of Liquid-to-Gas (L/G) ratio in the absorber and other process parameters,'' as well as other optimization procedures.[297] While foaming is mitigated by an antifoam injection regimen, the EPA further notes that the extent of foaming that could occur may be specific to the chemistry of the solvent and the source's flue gas conditions—foaming was not reported for MHI's KS–1 solvent when treating bituminous coal post-combustion flue gas at Petra Nova. Lastly, while biological fouling in the CO_2 absorber wash water and the SO_2 absorber caustic polisher has been observed, ''the current mitigation plan is to perform chemical shocking to remove this particular buildup.'' [298]

Based on the experiences of Boundary Dam Unit 3, key improvements can be implemented in future CCS deployments during initial design and construction. Improvements to PM and SO_2 controls can be made prior to operation of the CO_2 capture system. Where fly ash is present in the flue gas, wash systems can be installed to limit associated fouling. Additional redundancies and isolations of key heat-exchangers can be made to allow for in-line cleaning during operation. Redundancy of key equipment (*e.g.*, utilizing two CO_2 compressor trains instead of one) will further improve operational availability. A feasibility study for the Shand power plant, which is also operated by SaskPower, includes many such design improvements, at an overall cost that was less than the cost for Boundary Dam.[299]

(b) Other Coal-Fired Demonstrations

Several other projects have successfully demonstrated the capture component of CCS at electricity generating plants and other industrial facilities, some of which were previously noted in the discussion in the 2015 NSPS.[300] Since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant (Trona, California).[301] Amine-based carbon capture has further been demonstrated at AES's Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) coal-fired power plants, with the captured CO_2 being sold for use in the food processing industry.[302] At the 180 MW bituminous coal-fired Warrior Run plant, approximately 10 percent of the plant's CO_2 emissions (about 110,000 metric tons of CO_2 per year) has been captured since 2000 and sold to the food and beverage industry. AES's 320 MW Shady Point plant fires subbituminous and bituminous coal, and captured CO_2 from an approximate 5 percent slipstream (about 66,000 metric tons of CO_2 per year) from 2001 through around 2019.[303] These facilities, which have operated for multiple years, clearly show the technical feasibility of post-combustion carbon capture.

(2) EPAct05-Assisted CO_2 Capture Projects at Coal-Fired Steam Generating Units [304]

(a) Petra Nova

Petra Nova is a 240 MW-equivalent capture facility that is the first at-scale application of carbon capture at a coal-fired power plant in the U.S. The system is located at the subbituminous coal-

[295] S&P Global Market Intelligence (January 6, 2022). Only still-operating carbon capture project battled technical issues in 2021. *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/only-still-operating-carbon-capture-project-battled-technical-issues-in-2021-68302671.*

[296] SaskPower (October 18, 2022). *BD3 Status Update: Q3 2023. https://www.saskpower.com/about-us/Our-Company/Blog/2023/BD3-Status-Update-Q3-2023.*

[297] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[298] Pradoo, P., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286503.*

[299] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

[300] 80 FR 64548–54 (October 23, 2015).

[301] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[302] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[303] Shady Point Plant (River Valley) was sold to Oklahoma Gas and Electric in 2019. *https://www.oklahoman.com/story/business/columns/2019/05/23/oklahoma-gas-and-electric-acquires-aes-shady-point-after-federal-approval/60454346007/.*

[304] In the 2015 NSPS, the EPA provided a legal interpretation of the constraints on how the EPA could rely on EPAct05-assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111. Under that legal interpretation, ''these provisions [in the EPAct05] . . . preclude the EPA from relying solely on the experience of facilities that received [EPAct05] assistance, but [do] not . . . preclude the EPA from relying on the experience of such facilities in conjunction with other information.'' As part of the rulemaking action here, the EPA incorporates the legal interpretation and discussion of these EPAct05 provisions with respect the appropriateness of considering facilities that received EPAct05 assistance in determining whether CCS is adequately demonstrated, as found in the 2015 NSPS, 80 FR 64509, 64541–43 (October 23, 2015), and the supporting response to comments, EPA–HQ–OAR–2013–0495–11861 at pgs.113–134.

fired W.A. Parish Generating Station in Thompsons, Texas, and began operation in 2017, successfully capturing and sequestering CO_2 for several years. The system was put into reserve shutdown (*i.e.*, idled) in May 2020, citing the poor economics of utilizing captured CO_2 for EOR at that time. On September 13, 2023, JX Nippon announced that the carbon capture facility at Petra Nova had been restarted.[305] A final report from the National Energy Technology Laboratory (NETL) details the success of the project and what was learned from this first-of-a-kind demonstration at scale.[306] The project used Mitsubishi Heavy Industry's proprietary KM–CDR Process®, a process that is similar to an amine-based solvent process but that uses a proprietary solvent. During its operation, the project successfully captured 92.4 percent of the CO_2 from the slip stream of flue gas processed with 99.08 percent of the captured CO_2 sequestered by EOR.

The amount of flue gas treated at Petra Nova was consistent with a 240 MW size coal-fired steam EGU. The properties of the flue gas—composition, temperature, pressure, density, flowrate, *etc.*—are the same as would occur for a similarly sized coal-firing unit. Therefore, Petra Nova corroborates that the capture equipment—including the CO_2 absorption column, solvent regeneration column, balance of plant equipment, and the solvent itself—work at commercial scale and can achieve capture rates of 90 percent.

The Petra Nova project did experience periodic outages that were unrelated to the CO_2 capture facility and do not implicate the basis for the EPA's BSER determination.[307] These include outages at either the coal-fired steam generating unit (W.A. Parish Unit 8) or the auxiliary combined cycle facility, extreme weather events (Hurricane Harvey), and the operation of the EOR site and downstream oil recovery and processing. Outages at the coal-fired steam generating unit itself do not compromise the reliability of the CO_2 capture plant or the plant's ability to achieve a standard of performance based on CCS, as there would be no CO_2 to capture. Outages at the auxiliary combined cycle facility are also not relevant to the EPA's BSER determination, because the final BSER is not premised on the CO_2 capture plant using an auxiliary combined cycle plant for steam and power. Rather, the final BSER assumes the steam and power come directly from the associated steam generating unit. Extreme weather events can affect the operation of any facility. Furthermore, the BSER is not premised on EOR, and it is not dependent on downstream oil recovery or processing. Outages attributable to the CO_2 capture facility were 41 days in 2017, 34 days in 2018, and 29 days in 2019—outages decreased year-on-year and were on average less than 10 percent of the year. Planned and unplanned outages are normal for industrial processes, including steam generating units.

Petra Nova experienced some technical challenges that were addressed during its first 3 years of operation.[308] One of these issues was leaks from heat exchangers due to the properties of the gasket materials—replacement of the gaskets addressed the issue. Another issue was vibration of the flue gas blower due to build-up of slurry and solids carryover. W.A. Parish Unit 8 uses a wet limestone FGD scrubber to remove SO_2, and the flue gas connection to the capture plant is located at the bottom of the duct running from the wet-FGD to the original stack. A diversion wall and collection drains were installed to mitigate solids and slurry carryover. Regular maintenance is required to clean affected components and reduce the amount of slurry carryover to the quencher. Solids and slurry carryover also resulted in calcium scale buildup on the flue gas blower. Although calcium concentrations were observed to increase in the solvent, impacts of calcium on the quencher and capture plant chemistry were not observed. Some scaling may have been occurring in the cooling section of the quencher and would have been addressed during a planned outage in 2020. Another issue encountered was scaling related to the CO_2 compressor intercoolers, compressor dehydration system, and an associated heat exchanger. The issue was determined to be due to a material incompatibility of the CO_2 compressor intercooler, and the components were replaced during a 2018 planned outage. To mitigate the scaling prior to the replacement of those components, the compressor drain was also rerouted to the reclaimer and a backup filtering system was also installed and used, both of which proved to be effective. Some decrease in performance was also observed in heat exchangers. The presence of cooling tower fill (a solid medium used to increase surface area in cooling towers) in the cooling water system exchangers may have impacted performance. It is also possible that there could have been some fouling in heat exchangers. Fill was planned to be removed and fouling checked for during regular maintenance. Petra Nova did not observe fouling of the CO_2 absorber packing or high pressure drops across the CO_2 absorber bed, and Petra Nova also did not report any foaming of the solvent. Even with the challenges that were faced, Petra Nova was never restricted in reaching its maximum capture rate of 5,200 tons of CO_2 per day, a scale that was substantially greater than Boundary Dam Unit 3 (approximately 3,600 tons of CO_2 per day).

(b) Plant Barry

Plant Barry, a bituminous coal-fired steam generating unit in Mobile, Alabama, began using the KM–CDR Process® in 2011 for a fully integrated 25 MWe CCS project with a capture rate of 90 percent.[309] The CCS project at Plant Barry captured approximately 165,000 tons of CO_2 annually, which was then transported via pipeline and sequestered underground in geologic formations.[310]

(c) Project Tundra

Project Tundra is a carbon capture project in North Dakota at the Milton R. Young Station lignite coal-fired power plant. Project Tundra will capture up to 4 million metric tons of CO_2 per year for permanent geologic storage. One planned storage site is collocated with the power plant and is already fully permitted, while permitting for a second nearby storage site is in progress.[311] An air permit for the capture facility has also been issued by North Dakota Department of Environmental Quality. The project is designed to capture CO_2 at a rate of about 95 percent of the treated flue gas.[312] The capture plant will treat the flue gas from the 455 MW Unit 2 and additional flue gas from the 250 MW Unit 1, and will treat an equivalent capacity of 530 MW.[313] The project began a final FEED study in February 2023 with planned completion

[305] JX Nippon Oil & Gas Exploration Corporation. *Restart of the large-scale Petra Nova Carbon Capture Facility in the U.S.* (September 2023). *https://www.nex.jx-group.co.jp/english/newsrelease/upload_files/20230913EN.pdf.*

[306] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[307] *Id.*

[308] *Id.*

[309] U.S. Department of Energy (DOE). National Energy Technology Laboratory (NETL). *https://www.netl.doe.gov/node/1741.*

[310] 80 FR 64552 (October 23, 2015).

[311] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[312] See Document ID No. EPA–HQ–OAR–2023–0072–0632.

[313] *Id.*

in April 2024,[314] and, prior to selection by DOE for funding award negotiation, the project was scheduled to begin construction in 2024.[315] The project will use MHI's KS–21 solvent and the Advanced KM–CDR process. The MHI solvent KS–1 and an advanced MHI solvent (likely KS–21) were previously tested on the lignite post-combustion flue gas from the Milton R. Young Station.[316] To provide additional conditioning of the flue gas, the project is utilizing a wet electrostatic precipitator (WESP). A draft Environmental Assessment summarizing the project and potential environmental impacts was released by DOE.[317] Finally, Project Tundra was selected for award negotiation for funding from DOE.[318]

That this project has funding through the Bipartisan Infrastructure Law, and that this funding is facilitated through DOE's Office of Clean Energy Demonstration's (OCED) Carbon Capture Demonstration Projects Program, does not detract from the adequate demonstration of CCS. Rather, the goal of that program is, "to accelerate the implementation of integrated carbon capture and storage technologies and catalyze significant follow-on investments from the private sector to mitigate carbon emissions sources in industries across America." [319] For the commercial scale projects, the stated requirement of the funding opportunity announcement (FOA) is not that projects demonstrate CCS in general, but that they "demonstrate significant improvements in the efficiency, effectiveness, cost, operational and environmental performance of existing carbon capture technologies." [320] This implies that the basic technology already exists and is already demonstrated. The FOA further notes that the technologies used by the projects receiving funding should be proven such that, "the technologies funded can be readily replicated and deployed into commercial practice." [321] The EPA also notes that this and other on-going projects were announced well in advance of the FOA. Considering these factors, Project Tundra and other similarly funded projects are supportive of the determination that CCS is adequately demonstrated.

(d) Project Diamond Vault

Project Diamond Vault will capture up to 95 percent of CO_2 emissions from the 600 MW Madison Unit 3 at Brame Energy Center in Lena, Louisiana. Madison Unit 3 fires approximately 70 percent petroleum coke and 30 percent bituminous (Illinois Basin) coal in a circulating fluidized bed. The FEED study for the project is targeted for completion on September 9, 2024.[322] [323] Construction is planned to begin by the end of 2025 with commercial operation starting in 2028.[324] From the utility: "Government Inflation Reduction Act (IRA) funding through 45Q tax credits makes the project financially viable. With these government tax credits, the company does not expect a rate increase as a result of this project." [325]

(e) Other Projects

Other projects have completed or are in the process of completing feasibility work or FEED studies, or are taking other steps towards installing CCS on coal-fired steam generating units. These projects are summarized in the final TSD, *GHG Mitigation Measures for Steam Generating Units*, available in the docket. In general, these projects target capture rates of 90 percent or above and provide evidence that sources are actively pursuing the installation of CCS.

(3) CO_2 Capture Technology Vendor Statements

CO_2 capture technology providers have issued statements supportive of the application of systems and solvents for CO_2 capture at fossil fuel-fired EGUs. These statements speak to the decades of experience that technology providers have and as noted below, vendors attest, and offer guarantees that 90 percent capture rates are achievable. Generally, while there are many CO_2 capture methods available, solvent-based CO_2 capture from post-combustion flue gas is particularly applicable to fossil fuel-fired EGUs. Solvent-based CO_2 capture systems are commercially available from technology providers including Shell, Mitsubishi Heavy Industries (MHI), Linde/BASF, Fluor and ION Clean Energy.

Technology providers have made statements asserting extensive experience in CO_2 capture and the commercial availability of CO_2 capture technologies. Solvent-based CO_2 capture was first patented in the 1930s.[326] Since then, commercial solvent-based capture systems have been developed that are focused on applications to post-combustion flue gas. Several technology providers have over 30 years of experience applying solvent-based CO_2 capture to the post-combustion flue gas of fossil fuel-fired EGUs. In general, technology providers describe the technologies for CO_2 capture from post-combustion flue gas as "proven" or "commercially available" or "commercially proven" or "available now" and describe their experience with CO_2 capture from post-combustion flue gas as "extensive." CO_2 capture rates of 90 percent or higher from post-combustion flue gas have been proven by CO_2 capture technology providers using several commercially available solvents. Many of the available solvent technologies have over 50,000 hours of operation, equivalent to over 5 years of operation.

Shell has decades of experience in CO_2 capture systems. Shell notes that "[c]apturing and safely storing carbon is an option that's available now." [327] Shell has developed the CANSOLV® CO_2 capture system for CO_2 capture from post-combustion flue gas, a regenerable amine that the company claims has multiple advantages including "low parasitic energy consumption, fast kinetics and extremely low volatility." [328] Shell further notes, "Moreover, the technology has been designed for

[314] "An Overview of Minnkota's Carbon Capture Initiative—Project Tundra," 2023 LEC Annual Meeting, October 5, 2023.

[315] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[316] Laum, Jason. Subtask 2.4—Overcoming Barriers to the Implementation of Postcombustion Carbon Capture. *https://www.osti.gov/biblio/1580659.*

[317] DOE–EA–2197 Draft Environmental Assessment, August 17, 2023. *https://www.energy.gov/nepa/listings/doeea-2197-documents-available-download.*

[318] Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

[319] DOE. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-program-front-end-engineering-design-feed-studies.*

[320] DE–FOA–0002962. *https://oced-exchange.energy.gov/FileContent.aspx?FileID=86c47d5d-835c-4343-86e8-2ba27d9dc119.*

[321] *Id.*

[322] Diamond Vault Carbon Capture FEED Study. *https://netl.doe.gov/sites/default/files/netl-file/23CM_PSCC31_Bordelon.pdf.*

[323] Note that while the FEED study is EPAct05-assisted, the capture plant is not.

[324] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[325] *Id.*

[326] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[327] Shell Global—Carbon Capture and Storage. *https://www.shell.com/energy-and-innovation/carbon-capture-and-storage.html.*

[328] Shell Global—CANSOLV® CO_2 Capture System. *https://www.shell.com/business-customers/catalysts-technologies/licensed-technologies/emissions-standards/tail-gas-treatment-unit/cansolv-co2.html.*

reliability through its highly flexible turn-up and turndown capacity.'' [329] The company has stated that ''Over 90% of the CO_2 in exhaust gases can be effectively and economically removed through the implementation of Shell's carbon capture technology.'' [330] Shell also notes, ''Systems can be guaranteed for bulk CO_2 removal of over 90%.'' [331]

MHI in collaboration with Kansai Electric Power Co., Inc. began developing a solvent-based capture process (the KM CDR Process™) using the KS–1™ solvent in 1990.[332] MHI describes the extensive experience of commercial application of the solvent, ''KS–1™—a solvent whose high reliability has been confirmed by a track record of deliveries to 15 commercial plants worldwide.'' [333] Notable applications of KS–1™ and the KM–CDR Process™ include applications at Plant Barry and Petra Nova. Previously, MHI has achieved capture rates of greater than 90 percent over long periods and at full scale at the Petra Nova project where the KS–1™ solvent was used.[334] MHI has further improved on the original process and solvent by making available the Advanced KM CDR Process™ using the KS–21™ solvent. From MHI, ''Commercialization of KS–21™ solvent was completed following demonstration testing in 2021 at the Technology Centre Mongstad in Norway, one of the world's largest carbon capture demonstration facilities.'' [335] MHI has achieved CO_2 capture rates of 95 to 98 percent using both the KS–1™ and KS–21™ solvent at the Technology Centre Mongstad (TCM).[336] Higher capture rates under modified conditions were also measured, ''In addition, in testing conducted under modified operating conditions, the KS–21™ solvent delivered an industry-leading carbon capture rate was 99.8% and demonstrated the successful recovery of CO_2 from flue gas of lower concentration than the CO_2 contained in the atmosphere.'' [337]

Linde engineering in partnership with BASF has made available BASF's OASE® blue amine solvent technology for post-combustion CO_2 capture. Linde notes their experience: ''We have longstanding experience in the design and construction of chemical wash processes, providing the necessary amine-based solvent systems and the CO_2 compression, drying and purification system.'' [338] Linde also notes that ''[t]he BASF OASE® process is used successfully in more than 400 plants worldwide to scrub natural, synthesis and other industrial gases.'' [339] The OASE® blue technology has been successfully piloted at RWE Power, Niederaussem, Germany (from 2009 through 2017; 55,000 operating hours) and the National Center for Carbon Capture in Wilsonville, Alabama (January 2015 through January 2016; 3,200 operating hours). Based on the demonstrated performance, Linde concludes that ''PCC plants combining Linde's engineering skills and BASF's OASE® blue solvent technology are now commercially available for a wide range of applications.'' [340] Linde and BASF have demonstrated capture rates over 90 percent and operating availability [341] rates of more than 97 percent during 55,000 hours of operation.

Fluor provides a solvent technology (Econamine FG Plus) and EPC services for CO_2 capture. Fluor describes their technology as ''proven,'' noting that, ''Proven technology. Fluor Econamine FG Plus technology is a propriety carbon capture solution with more than 30 licensed plants and more than 30 years of operation.'' [342] Fluor further notes, ''The technology builds on Fluor's more than 400 CO_2 removal units in natural gas and synthesis gas processing.'' [343] Fluor further states, ''Fluor is a global leader in CO_2 capture [. . .] with long-term commercial operating experience in CO_2 recovery from flue gas.'' On the status of Econamine FG Plus, Fluor notes that the ''[the] Technology [is] commercially proven on natural gas, coal, and fuel oil flue gases,'' and further note that ''[o]perating experience includes using steam reformers, gas turbines, gas engines, and coal/natural gas boilers.''

ION Clean Energy is a company focused on post-combustion carbon capture founded in 2008. ION's ICE–21 solvent has been used at NCCC and TCM Norway.[344] ION has achieved capture rates of 98 percent using the ICE–31 solvent.

(4) CCS User Statements on CCS

A number of the companies who have either completed large scale pilot projects or who are currently developing full scale projects have also indicated that CCS technology is currently a viable technology for large coal-fired power plants. In 2011, announcing a decision not to move forward with the first full scale commercial CCS installation of a carbon capture system on a coal plant, AEP did not cite any technology concerns, but rather indicated that ''it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place.'' [345] Enchant Energy, a company developing CCS for coal-fired power plants explained that its FEED study for the San Juan Generating Station, ''shows that the technical and business case for adding carbon capture to existing coal-fired power plants is strong.'' [346] Rainbow Energy, who is developing a carbon capture project at the Coal Creek Power Station in North Dakota explains, ''CCUS technology has been proven and is an economical option for a facility like Coal Creek Station. We see CCUS as the best option to manage CO_2 emissions at our facility.'' [347]

(5) State CCS Requirements

Several states encourage or even require sources to install CCS. These state requirements further indicate that CCS is well-established and effective. These state laws include the Illinois 2021 Climate and Equitable Jobs Act, which requires privately owned coal-

[329] Shell Catalysts & Technologies—Shell CANSOLV® CO_2 Capture System. *https://catalysts.shell.com/en/Cansolv-co2-fact-sheet.*

[330] *Id.*

[331] *Id.*

[332] Mitsubishi Heavy Industries—CO_2 Capture Technology—CO_2 Capture Process. *https://www.mhi.com/products/engineering/co2plants_process.html.*

[333] *Id.*

[334] Note: Petra Nova is an EPAct05-assisted project. W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[335] *Id.*

[336] Mitsubishi Heavy Industries, ''Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New KS–21™ Solvent for CO_2 Capture,'' *https://www.mhi.com/news/211019.html.*

[337] *Id.*

[338] Linde Engineering—Post Combustion Capture. *https://www.linde-engineering.com/en/process-plants/co2-plants/carbon-capture/post-combustion-capture/index.html.*

[339] Linde and BASF—Carbon capture storage and utilisation. *https://www.linde-engineering.com/en/images/Carbon-capture-storage-utilisation-Linde-BASF_tcm19-462558.pdf.*

[340] *Id.*

[341] Operating availability is the percent of time that the CO_2 capture equipment is available relative to its planned operation.

[342] Fluor—Comprehensive Solutions for Carbon Capture. *https://www.fluor.com/client-markets/energy/production/carbon-capture.*

[343] Fluor—Econamine FG Plus℠. *https://www.fluor.com/sitecollectiondocuments/qr/econamine-fg-plus-brochure.pdf.*

[344] ION Clean Energy—Company. *https://www.ioncleanenergy.com/company.*

[345] *https://www.aep.com/news/releases/read/1206/AEP-Places-Carbon-Capture-Commercialization-On-Hold-Citing-Uncertain-Status-Of-Climate-Policy-Weak-Economy.*

[346] Enchant Energy. What is Carbon Capture and Sequestration (CCS)? *https://enchantenergy.com/carbon-capture-technology/.*

[347] Rainbow Energy Center. Carbon Capture. *https://rainbowenergycenter.com/what-we-do/carbon-capture/.*

fired units to reduce emissions to zero by 2030 and requires publicly owned coal-fired units to reduce emissions to zero by 2045.[348] Illinois has also imposed CCS-based CO_2 emission standards on new coal-fired power plants since 2009 when the state adopted its Clean Coal Portfolio Standard law.[349] The statute required an initial capture rate of 50 percent when enacted but steadily increased the capture rate requirement to 90 percent in 2017, where it remains.

Michigan in 2023 established a 100 percent clean energy requirement by 2040 with a nearer term 80 percent clean energy by 2035 requirement.[350] The statute encourages the application of CCS by defining ''clean energy'' to include generation resources that achieve 90 percent carbon capture.

California identifies carbon capture and sequestration as a necessary tool to reduce GHG emissions within its 2022 scoping plan update[351] and, that same year, enacted a statutory requirement through Assembly Bill 1279[352] requiring the state to plan and implement policies that enable carbon capture and storage technologies.

Several states in different parts of the country have adopted strategic and planning frameworks that also encourage CCS. Louisiana, which in 2020 set an economy-wide net-zero goal by 2050, has explored policies that encourage CCS deployment in the power sector. The state's 2022 Climate Action Plan proposes a Renewable and Clean Portfolio Standard requiring 100 percent renewable or clean energy by 2035.[353] That proposal defines power plants achieving 90 percent carbon capture as a qualifying clean energy resource that can be used to meet the standard.

Pennsylvania's 2021 Climate Action Plan notes that the state is well positioned to install CCS to transition the state's electric fleet to a zero-carbon economy.[354] The state also established an interagency workgroup in 2019 to identify ways to speed the deployment of CCS.

The Governor of North Dakota announced in 2021 an economy-wide carbon neutral goal by 2030.[355] The announcement singled out the Project Tundra Initiative, which is working to apply CCS technology to the state's Milton R. Young Power Station.

The Governor of Wyoming has broadly promoted a Decarbonizing the West initiative that includes the study of CCS technologies to reduce carbon emissions from the region.[356] A 2024 Wyoming law also requires utilities in the state to install CCS technologies on a portion of their existing coal-fired power plants by 2033.[357]

(6) Variable Load and Startups and Shutdowns

In this section of the preamble, the EPA considers the effects of variable load and startups and shutdowns on the achievability of 90 percent capture. First, the coal-fired steam generating unit can itself turndown[358] to only about 40 percent of its maximum design capacity. Due to this, coal-fired EGUs have relatively high duty cycles[359]—that is, they do not cycle as frequently as other sources and typically have high average loads when operating. In 2021, coal-fired steam generating units had an average duty cycle of 70 percent, and more than 75 percent of units had duty cycles greater than 60 percent.[360] Prior demonstrations of CO_2 capture plants on coal-fired steam generating units have had turndown limits of approximately 60 percent of throughput for Boundary Dam Unit 3[361] and about 70 percent throughput for Petra Nova.[362] Based on the technology currently available, turndown to throughputs of 50 percent[363] are achievable for a single capture train.[364] Considering that coal units can typically only turndown to 40 percent, a 50 percent turndown ratio for the CO_2 capture plant is likely sufficient for most sources, although utilizing two CO_2 capture trains would allow for turndown to as low as 25 percent of throughput. When operating at less than maximum throughputs, the CO_2 capture facility actually achieves higher capture efficiencies, as evidenced by the data collected at Boundary Dam Unit 3.[365] Data from the Shand Feasibility Report suggests that, for a solvent and design achieving 90 percent capture at 100 percent of net load, 97.5 percent capture is achievable at 62.5 percent of net load.[366] Considering these factors, CO_2 capture is, in general, able to meet the variable load of coal-fired steam generating units without any adverse impact on the CO_2 capture rate. In fact, operation at lower loads may lead to

[348] State of Illinois General Assembly. Public Act 102–0662: Climate and Equitable Jobs Act. 2021. *https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf.*

[349] State of Illinois General Assembly. Public Act 095–1027: Clean Coal Portfolio Standard Law. *https://www.ilga.gov/legislation/publicacts/95/PDF/095-1027.pdf.*

[350] State of Michigan Legislature. Public Act 235 of 2023. Clean and Renewable Energy and Energy Waste Reduction Act. *https://legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0235.pdf.*

[351] California Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality. *https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.*

[352] State of California Legislature. Assembly Bill 1279 (2022). The California Climate Crisis Act. *https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB1279.*

[353] Louisiana Climate Initiatives Task Force. Louisiana Climate Action Plan (February 1, 2022). *https://gov.louisiana.gov/assets/docs/CCI-Task-force/CAP/ClimateActionPlanFinal.pdf.*

[354] Pennsylvania Dept. of Environmental Protection. Pennsylvania Climate Action Plan (2021). *https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx.*

[355] *https://www.governor.nd.gov/news/updated-waudio-burgum-addresses-williston-basin-petroleum-conference-issues-carbon-neutral.*

[356] *https://westgov.org/initiatives/overview/decarbonizing-the-west.*

[357] State of Wyoming Legislature. SF0042. Low-carbon Reliable Energy Standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042.*

[358] Here, ''turndown'' is the ability of a facility to turn down some process value, such as flowrate, throughput or capacity. Typically, this is expressed as a ratio relative to operation at its maximum instantaneous capability. Because processes are designed to operate within specific ranges, turndown is typically limited by some lower threshold.

[359] Here, ''duty cycle'' is the ratio of the gross amount of electricity generated relative to the amount that could be potentially generated if the unit operated at its nameplate capacity during every hour of operation. Duty cycle is thereby an indication of the amount of cycling or load following a unit experiences (higher duty cycles indicate less cycling, *i.e.,* more time at nameplate capacity when operating). Duty cycle is different from capacity factor, as the latter also quantifies the amount that the unit spends offline.

[360] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data website: *https://campd.epa.gov.*

[361] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[362] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[363] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

[364] Here, a ''train'' in this context is a series of connected sequential process equipment. For carbon capture, a process train can include the quencher, absorber, stripper, and compressor. Rather than doubling the size of a single train of process equipment, a source could use two equivalent sized trains.

[365] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *Reducing the CO^2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[366] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

higher achievable capture rates over long periods of time.

Coal-fired steam generating units also typically have few startups and shutdowns per year, and CO_2 emissions during those periods are low. Although capacity factor has declined in recent years, as noted in section IV.D.3 of the preamble, the number of startups per year has been relatively stable. In 2011, coal-fired sources had about 10 startups on average. In 2021, coal-fired steam generating units had only 12 startups on average, see the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket. Prior to generation of electricity, coal-fired steam generating units use natural gas or distillate oil—which have a lower carbon content than coal—because of their ignition stability and low ignition temperature. Heat input rates during startup are relatively low, to slowly raise the temperature of the boiler. Existing natural gas- or oil-fired ignitors designed for startup purposes are generally sized for up to 15 percent of the maximum heat-input. Considering the low heat input rate, use of fuel with a lower carbon content, and the relatively few startups per year, the contribution of startup to total GHG emissions is relatively low. Shutdowns are relatively short events, so that the contribution to total emissions are also low. The emissions during startup and shutdown are therefore small relative to emissions during normal operation, so that any impact is averaged out over the course of a year.

Furthermore, the IRC section 45Q tax credit provides incentive for units to operate more. Sources operating at higher capacity factors are likely to have fewer startups and shutdowns and spend less time at low loads, so that their average load would be higher. This would further minimize the insubstantial contribution of startups and shutdowns to total emissions. Additionally, as noted in the preceding sections of the preamble, new solvents achieve capture rates of 95 percent at full load, and ongoing projects are targeting capture rates of 95 percent. Considering all of these factors, startup and shutdown, in general, do not affect the achievability of 90 percent capture over long periods (*i.e.,* a year).

(7) Coal Rank

CO_2 capture at coal-fired steam generating units achieves 90 percent capture, for the reasons detailed in sections VII.C.1.a.i(B)(1) through (6) of this preamble. Moreover, 90 percent capture is achievable for all coal types because amine solvents have been used to remove CO_2 from a variety of flue gas compositions including a broad range of different coal ranks, differences in CO_2 concentration are slight and the capture process can be designed to the appropriate scale, amine solvents have been used to capture CO_2 from flue gas with much lower CO_2 concentrations, and differences in flue gas impurities due to different coal compositions can be managed or mitigated by controls.

As detailed in the preceding sections, CO_2 capture has been operated on flue gas from the combustion of a broad range of coal ranks including lignite, bituminous, subbituminous, and anthracite coals. Post-combustion CO_2 capture from the flue gas of an EGU firing lignite has been demonstrated at the Boundary Dam Unit 3 EGU (Saskatchewan, Canada). Most lignites have a higher ash and moisture content than other coal types and, in that respect, the flue gas can be more challenging to manage for CO_2 capture. Amine CO_2 capture has also been used to treat lignite post-combustion flue gas in pilot studies at the Milton R. Young station (North Dakota).[367] CO_2 capture solvents have been used to treat subbituminous post-combustion flue gas from W.A. Parish Generating Station (Texas),[368] and the bituminous post-combustion flue gas from Plant Barry (Mobile, Alabama),[369] Warrior Run (Maryland),[370] and Argus Cogeneration Plant (California).[371] Amine solvents have also been used to remove CO_2 from the flue gas of the bituminous- and subbituminous-fired Shady Point plant.[372] CO_2 capture solvents have been used to treat anthracite post-combustion flue gas at the Wilhelmshaven power plant (Germany).[373] There are also ongoing projects that will apply CCS to the flue gas of coal-fired steam generating units. The EPA considers these ongoing projects to be indicative of the confidence that industry stakeholders have in CCS. These include Project Tundra at the lignite-fired Milton R. Young station (North Dakota),[374] Project Diamond Vault at the petroleum coke- and subbituminous-fired Brame Energy Center Madison Unit 3 (Louisiana)[375] and two units at the Jim Bridger Plant (Wyoming).[376]

Different coal ranks have different carbon contents, affecting the concentration of CO_2 in flue gas. In general, however, CO_2 concentration of coal combustion flue gas varies only between 13 and 15 percent. Differences in CO_2 concentration can be accounted for by appropriately designing the capture equipment, including sizing the absorber columns. As detailed in section VIII.F.4.c.iv of the preamble, CO_2 has been captured from the post-combustion flue gas of NGCCs, which typically have a CO_2 concentration of 4 percent.

Prior to emission controls and pre-conditioning, characteristics of different coal ranks and boiler design result in other differences in the flue gas composition, including in the concentration of SO_2, NO_X, PM, and trace impurities. Such impurities in the flue gas can react with the solvent or cause fouling of downstream processes. However, in general, most existing coal-fired steam generating units in the U.S. have controls that are necessary for the pre-conditioning of flue gas prior to the CO_2 capture plant, including PM and SO_2 controls. For those sources without an FGD for SO_2 control, the EPA included the costs of adding an FGD in its cost analysis. Other marginal differences in flue gas impurities can be managed by appropriately designing the polishing column (direct contact cooler) for the individual source's flue gas. Trace impurities can be mitigated using conventional controls in the solvent reclaiming process (*e.g.,* an activated carbon bed).

Considering the broad range of coal post-combustion flue gases amine solvents have been operated with, that solvents capture CO_2 from flue gases with lower CO_2 concentrations, that the capture process can be designed for different CO_2 concentrations, and that flue gas impurities that may differ by coal rank can be managed by controls, the EPA therefore concludes that 90 percent capture is achievable across all coal ranks, including waste coal.

[367] Laum, Jason. Subtask 2.4—Overcoming Barriers to the Implementation of Postcombustion Carbon Capture. *https://www.osti.gov/biblio/1580659.*

[368] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[369] U.S. Department of Energy (DOE). National Energy Technology Laboratory (NETL). *https://www.netl.doe.gov/node/1741.*

[370] Dooley, J.J., *et al.* (2009). "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[371] *Id.*

[372] *Id.*

[373] Reddy, *et al.* Energy Procedia, 37 (2013) 6216–6225.

[374] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[375] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[376] 2023 Integrated Resource Plan Update, PacifiCorp, April 1, 2024, *https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023_IRP_Update.pdf.*

(8) Natural Gas-Fired Combustion Turbines

Additional information supporting the EPA's determination that 90 percent capture of CO_2 from steam generating units is adequately demonstrated is the experience from CO_2 capture from natural gas-fired combustion turbines. The EPA describes this information in section VIII.F.4.c.iv(B)(1), including explaining how information about CO_2 capture from coal-fired steam generating units also applies to natural gas-fired combustion turbines. The reverse is true as well; information about CO_2 capture from natural gas-fired turbines can be applied to coal fired-units, for much the same reasons.

(9) Summary of Evidence Supporting BSER Determination Without EPAct05-Assisted Projects

As noted above, under the EPA's interpretation of the EPAct05 provisions, the EPA may not rely on capture projects that received assistance under EPAct05 as the sole basis for a determination of adequate demonstration, but the EPA may rely on those projects to support or corroborate other information that supports such a determination. The information described above that supports the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated, without consideration of the EPAct05-assisted projects, includes (i) the information concerning Boundary Dam, coupled with engineering analysis concerning key improvements that can be implemented in future CCS deployments during initial design and construction (*i.e.*, all the information in section VII.C.1.a.i.(B)(1)(a) and the information concerning Boundary Dam in section VII.C.1.a.i.(B)(1)(b)); (ii) the information concerning other coal-fired demonstrations, including the Argus Cogeneration Plant and AES's Warrior Run (*i.e.*, all the information concerning those sources in section VII.C.1.a.i.(B)(1)(a)); (iii) the information concerning industrial applications of CCS (*i.e.*, all the information in section VII.C.1.a.i.(A)(1); (iv) the information concerning CO_2 capture technology vendor statements (*i.e.*, all the information in section VII.C.1.a.i.(B)(3)); (v) information concerning carbon capture at natural gas-fired combustion turbines other than EPAct05-assisted projects (*i.e.*, all the information other than information about EPAct05-assisted projects in section VIII.F.4.c.iv.(B)(1)). All this information by itself is sufficient to support the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated. Substantial additional information from EPAct05-assisted projects, as described in section VII.C.1.a.i.(B), provides additional support and confirms that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated.

(C) CO_2 Transport

The EPA is finalizing its determination that CO_2 transport by pipelines as a component of CCS is adequately demonstrated. The EPA anticipates that in the coming years, a large-scale interstate pipeline network may develop to transport CO_2. Indeed, PHMSA is currently engaged in a rulemaking to update and strengthen its safety regulations for CO_2 pipelines, which assumes that such a pipeline network will develop.[377] For purposes of determining the CCS BSER in this final action, however, the EPA did not base its analysis of the availability of CCS on the projected existence of a large-scale interstate pipeline network. Instead, the EPA adopted a more conservative approach. The BSER is premised on the construction of relatively short lateral pipelines that extend from the source to the nearest geologic storage reservoir. While the EPA anticipates that sources would likely avail themselves of an existing interstate pipeline network if one were constructed and that using an existing network would reduce costs, the EPA's analysis focuses on steps that an individual source could take to access CO_2 storage independently.

EGUs that do not currently capture and transport CO_2 will need to construct new CO_2 pipelines to access CO_2 storage sites, or make arrangements with pipeline owners and operators who can do so. Most coal-fired steam EGUs, however, are located in relatively close proximity to deep saline formations that have the potential to be used as long-term CO_2 storage sites.[378] Of existing coal-fired steam generating capacity with planned operation during or after 2039, more than 50 percent is located less than 32 km (20 miles) from potential deep saline sequestration sites, 73 percent is located within 50 km (31 miles), 80 percent is located within 100 km (62 miles), and 91 percent is within 160 km (100 miles). While the EPA's analysis focuses on the geographic availability of deep saline formations, unmineable coal seams and depleted oil and gas reservoirs could also potentially serve as storage formations depending on site-specific characteristics. Thus, for the majority of sources, only relatively short pipelines would be needed for transporting CO_2 from the source to the sequestration site. For the reasons described below, the EPA believes that both new and existing EGUs are capable of constructing CO_2 pipelines as needed. New EGUs may also be planned to be co-located with a storage site so that minimal transport of the CO_2 is required. The EPA has assurance that the necessary pipelines will be safe because the safety of existing and new supercritical CO_2 pipelines is comprehensively regulated by PHMSA.[379]

(1) CO_2 Transport Demonstrations

The majority of CO_2 transported in the United States is moved through pipelines. CO_2 pipelines have been in use across the country for nearly 60 years. Operation of this pipeline infrastructure for this period of time establishes that the design, construction, and operational requirements for CO_2 pipelines have been adequately demonstrated.[380] PHMSA reported that 8,666 km (5,385 miles) of CO_2 pipelines were in operation in 2022, a 14 percent increase in CO_2 pipeline miles since 2011.[381] This pipeline infrastructure continues to expand with a number of anticipated projects underway.

The U.S. CO_2 pipeline network includes major trunkline (*i.e.*, large capacity) pipelines as well as shorter, smaller capacity lateral pipelines connecting a CO_2 source to a larger trunkline or connecting a CO_2 source to a nearby CO_2 end use. While CO_2

[377] PHMSA submitted the associated Notice of Proposed Rulemaking to the White House Office of Management and Budget on February 1, 2024 for pre-publication review. The notice stated that the proposed rulemaking would enhance safety regulations to "accommodate an anticipated increase in the number of carbon dioxide pipelines and volume of carbon dioxide transported." Office of Management and Budget. *https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2137-AF60.*

[378] Individual saline formations would require site-specific characterization to determine their suitability for geologic sequestration and the potential capacity for storage.

[379] PHMSA additionally initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of CO_2 pipelines following investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020. For more information, see: *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[380] For additional information on CO_2 transportation infrastructure project timelines, costs and other details, please see EPA's final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[381] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, "Hazardous Annual Liquid Data." 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

pipelines are generally more economical, other methods of CO_2 transport may also be used in certain circumstances and are detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units*.

(a) Distance of CO_2 Transport for Coal-Fired Power Plants

An important factor in the consideration of the feasibility of CO_2 transport from existing coal-fired steam generating units to sequestration sites is the distance the CO_2 must be transported. As discussed in section VII.C.1.a.i(D), potential sequestration formations include deep saline formations, unmineable coal seams, and oil and gas reservoirs. Based on data from DOE/NETL studies of storage resources, of existing coal-fired steam generating capacity with planned operation during or after 2039, 80 percent is within 100 km (62 miles) of potential deep saline sequestration sites, and another 11 percent is within 160 km (100 miles).[382] In other words, 91 percent of this capacity is within 160 km (100 miles) of potential deep saline sequestration sites. In gigawatts, of the 81 GW of coal-fired steam generation capacity with planned operation during or after 2039, only 16 GW is not within 100 km (62 miles) of a potential saline sequestration site, and only 7 GW is not within 160 km (100 mi). The vast majority of these units (on the order of 80 percent) can reach these deep saline sequestration sites by building an intrastate pipeline. This distance is consistent with the distances referenced in studies that form the basis for transport cost estimates for this final rule.[383] While the EPA's analysis focuses on the geographic availability of deep saline formations, unmineable coal seams and depleted oil and gas reservoirs could also potentially serve as storage formations depending on site-specific characteristics.

Of the 9 percent of existing coal-fired steam generating capacity with planned operation during or after 2039 that is not within 160 km (100 miles) of a potential deep saline sequestration site, 5 percent is within 241 km (150 miles) of potential saline sequestration sites, an additional 3 percent is within 322 km (200 miles) of potential saline sequestration sites, and another 1 percent is within 402 km (250 miles) of potential sequestration sites. In total, assuming all existing coal-fired steam generating capacity with planned operation during or after 2039 adopts CCS, the EPA analysis shows that approximately 8,000 km (5,000 miles) of CO_2 pipelines would be constructed by 2032. This includes units located at any distance from sequestration. Note that this value is not optimized for the least total pipeline length, but rather represents the approximate total pipeline length that would be required if each power plant constructed a lateral pipeline connecting their power plant to the nearest potential saline sequestration site.[384]

Additionally, the EPA's compliance modeling projects 3,300 miles of CO_2 pipeline buildout in the baseline and 4,700 miles of pipeline buildout in the policy scenario. This is comparable to the 4,700 to 6,000 miles of CO_2 pipeline buildout estimated by other simulations examining similar scenarios of coal CCS deployment.[385] Over 5 years, this total projected CO_2 pipeline capacity would amount to about 660 to 940 miles per year on average.[386] This projected pipeline mileage is comparable to other types of pipelines that are regularly constructed in the United States each year. For example, based on data collected by EIA, the total annual mileage of natural gas pipelines constructed over the 2017–2021 period ranged from approximately 1,000 to 2,500 miles per year. The projected annual average CO_2 pipeline mileage is less than each year in this historical natural gas pipeline range, and significantly less than the upper end of this range.

The EPA also notes that the pipeline construction estimates presented in this section are not additive with the natural gas co-firing pipeline construction estimates presented below because individual sources will not elect to utilize both compliance methods. In other words, more pipeline buildout for one compliance method necessarily means less pipeline buildout for the other method. Therefore, there is no compliance scenario in which the total pipeline construction is equal to the sum of the CCS and natural gas co-firing pipeline estimates presented in this preamble.

While natural gas line construction may be easier in some circumstances given the uniform federal regulation that governs those such construction, the historical trends support the EPA's conclusion that constructing less CO_2 pipeline length over a several year period is feasible.

(b) CO_2 Pipeline Examples

PHMSA reported that 8,666 km (5,385 miles) of CO_2 pipelines were in operation in 2022.[387] Due to the unique nature of each project, CO_2 pipelines vary widely in length and capacity. Examples of projects that have utilized CO_2 pipelines include the following: Beaver Creek (76 km), Monell (52.6 km), Bairoil (258 km), Salt Creek (201 km), Sheep Mountain (656 km), Slaughter (56 km), Cortez (808 km), Central Basin (231 km), Canyon Reef Carriers (354 km), and Choctaw (294 km). These pipelines range in capacity from 1.6 million tons per year to 27 million tons per year, and transported CO_2 for uses such as EOR.[388]

Most sources deploying CCS are anticipated to construct pipelines that run from the source to the sequestration site. Similar CO_2 pipelines have been successfully constructed and operated in the past. For example, a 109 km (68 mile) CO_2 pipeline was constructed from a fertilizer plant in Coffeyville, Kansas, to the North Burbank Unit, an EOR operation in Oklahoma.[389] Chaparral Energy entered a long-term CO_2 purchase and sale agreement with a subsidiary of CVR Energy for the capture of CO_2 from CVR's nitrogen fertilizer plant in 2011.[390] The pipeline

[382] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf*.

[383] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[384] Note that multiple coal-fired EGUs may be located at each power plant.

[385] CO_2 Pipeline Analysis for Existing Coal-Fired Powerplants. Chen et. al. Los Alamos National Lab. 2024. *https://permalink.lanl.gov/object/tr?what=info:lanl-repo/lareport/LA-UR-24-23321*.

[386] In the EPA's representative timeline, the CO_2 pipeline is constructed in an 18-month period. In practice, all CO_2 pipeline construction projects would be spread over a larger time period. In the Transport and Storage Timeline Summary, ICF (2024), available in Docket ID EPA–HQ–OAR–2023–0072, permitting is 1.5 years. Some CO_2 pipeline construction would therefore likely begin by the start of 2028, or even earlier considering on-going projects. With the one-year compliance extension for delays outside of the owner/operators control that would provide extra time if there were challenges in building pipelines, the construction on CO_2 pipelines could occur during 2032.

[387] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, "Hazardous Annual Liquid Data." 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids*.

[388] Noothout, Paul. Et. Al. (2014). "CO_2 Pipeline infrastructure—lessons learnt." *https://www.sciencedirect.com/science/article/pii/S187661021402864*.

[389] Rassenfoss, Stephen. (2014). "Carbon Dioxide: From Industry to Oil Fields." *ttps://jpt.spe.org/carbon-dioxide-industry-oil-fields*.

[390] GlobeNewswire. "Chaparral Energy Agrees to a CO2 Purchase and Sale Agreement with CVR Energy for Capture of CO_2 for Enhanced Oil Recovery." March 29, 2011. *https://www.globenewswire.com/news-release/2011/03/29/443163/10562/en/Chaparral-Energy-Agrees-to-a-CO2-Purchase-and-Sale-Agreement-With-CVR-*

was then constructed, and operations started in 2013.[391] Furthermore, a 132 km (82 mile) pipeline was constructed from the Terrell Gas facility (formerly Val Verde) in Texas to supply CO_2 for EOR projects in the Permian Basin.[392] Additionally, the Kemper Country CCS project in Mississippi, was designed to capture CO_2 from an integrated gasification combined cycle power plant, and transport CO_2 via a 96 km (60 mile) pipeline to be used in EOR.[393] Construction for this facility commenced in 2010 and was completed in 2014.[394] Furthermore, the Citronelle Project in Alabama, which was the largest demonstration of a fully integrated, pulverized coal-fired CCS project in the United States as of 2016, utilized a dedicated 19 km (12 mile) pipeline constructed by Denbury Resources in 2011 to transport CO_2 to a saline storage site.[395]

(c) EPAct05-Assisted CO_2 Pipelines for CCS

Consistent with the EPA's legal interpretation that the Agency can rely on experience from EPAct05 funded facilities in conjunction with other information, this section provides additional examples of CO_2 pipelines with EPAct05 funding. CCS projects with EPAct05 funding have built pipelines to connect the captured CO_2 source with sequestration sites, including Illinois Industrial Carbon Capture and Storage in Illinois, Petra Nova in Texas, and Red Trail Energy in North Dakota. The Petra Nova project, which restarted operations in September 2023,[396] transports CO_2 via a 131 km (81 mile) pipeline to the injection site, while the Illinois Industrial Carbon Capture project and Red Trail Energy transport CO_2 using pipelines under 8 km (5 miles) long.[397] [398] [399] Additionally, Project Tundra, a saline sequestration project planned at the lignite-fired Milton R. Young Station in North Dakota will transport CO_2 via a 0.4 km (0.25 mile) pipeline.[400]

(d) Existing and Planned CO_2 Trunklines

Although the BSER is premised on the construction of pipelines that connect the CO_2 source to the sequestration site, in practice some sources may construct short laterals to existing CO_2 trunklines, which can reduce the number of miles of pipeline that may need to be constructed. A map displaying both existing and planned CO_2 pipelines, overlayed on potential geologic sequestration sites, is available in the final TSD, *GHG Mitigation Measures for Steam Generating Units*. Pipelines connect natural CO_2 sources in south central Colorado, northeast New Mexico, and Mississippi to oil fields in Texas, Oklahoma, New Mexico, Utah, and Louisiana. The Cortez pipeline is the longest CO_2 pipeline, and it traverses over 800 km (500) miles from southwest Colorado to Denver City, Texas CO_2 Hub, where it connects with several other CO_2 pipelines. Many existing CO_2 pipelines in the U.S. are located in the Permian Basin region of west Texas and eastern New Mexico. CO_2 pipelines in Wyoming, Texas, and Louisiana also carry CO_2 captured from natural gas processing plants and refineries to EOR projects. Additional pipelines have been constructed to meet the demand for CO_2 transportation. A 170 km (105 mile) CO_2 pipeline owned by Denbury connecting oil fields in the Cedar Creek Anticline (located along the Montana-North Dakota border) to CO_2 produced in Wyoming was completed in 2021, and a 30 km (18 mile) pipeline also owned by Denbury connects to the same oil field and was completed in 2022.[401] [402] These pipelines form a network with existing pipelines in the region—including the Denbury Greencore pipeline, which was completed in 2012 and is 232 miles long, running from the Lost Cabin gas plant in Wyoming to Bell Creek Field in Montana.[403]

In addition to the existing pipeline network, there are a number of large CO_2 trunklines that are planned or in progress, which could further reduce the number of miles of pipeline that a source may need to construct. Several major projects have recently been announced to expand the CO_2 pipeline network across the United States. For example, the Summit Carbon Solutions Midwest Carbon Express project has proposed to add more than 3,200 km (2,000) miles of dedicated CO_2 pipeline in Iowa, Nebraska, North Dakota, South Dakota, and Minnesota. The Midwest Carbon Express is projected to begin operations in 2026. Further, Wolf Carbon Solutions has recently announced that it plans to refile permit applications for the Mt. Simon Hub, which will expand the CO_2 pipeline by 450 km (280 miles) in the Midwest. Tallgrass announced in 2022 a plan to convert an existing 630 km (392 mile) natural gas pipeline to carry CO_2 from an ADM ethanol production facility in Nebraska to a planned commercial-scale CO_2 sequestration hub in Wyoming aimed for completion in 2024.[404] Recently, as part of agreeing to a communities benefits plan, a number of community groups have agreed that they will support construction of the Tallgrass pipeline in Nebraska.[405] While the construction of larger networks of trunklines could facilitate CCS for power plants, the BSER is not predicated on the buildout of a trunkline network and the existence of future trunklines was not assumed in the EPA's feasibility or costing analysis. The EPA's analysis is conservative in that it does not presume the buildout of trunkline networks. The development of more robust and interconnected pipeline systems over the next several years would merely lower the EPA's

Energy-for-Capture-of-CO2-for-Enhanced-Oil-Recovery.html.

[391] Chaparral Energy. "A 'CO₂ Midstream' Overview: EOR Carbon Management Workshop." December 10, 2013. *https://www.co2conference.net/wp-content/uploads/2014/01/13-Chaparral-CO2-Midstream-Overview-2013.12.09new.pdf.*

[392] "Val Verde Fact Sheet: Commercial EOR using Anthropogenic Carbon Dioxide." *https://sequestration.mit.edu/tools/projects/val_verde.html.*

[393] Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project. *https://sequestration.mit.edu/tools/projects/kemper.html.*

[394] Office of Fossil Energy and Carbon Management. Southern Company—Kemper County, Mississippi. *https://www.energy.gov/fecm/southern-company-kemper-county-mississippi.*

[395] Citronelle Project. National Energy Technology Laboratory. (2018). *https://www.netl.doe.gov/sites/default/files/2018-11/Citronelle-SECARB-Project.PDF.*

[396] Jacobs, Trent. (2023). "A New Day Begins for Shuttered Petra Nova CCUS." *https://jpt.spe.org/a-new-day-begins-for-shuttered-petra-nova-ccus.*

[397] Technical Review of Subpart RR MRV Plan for Petra Nova West Ranch Unit. (2021). *https://www.epa.gov/system/files/documents/2021-09/wru_decision.pdf.*

[398] Technical Review of Subpart RR MRV Plan for Archer Daniels Midland Illinois Industrial Carbon Capture and Storage Project. (2017). *https://www.epa.gov/sites/default/files/2017-01/documents/adm_final_decision.pdf.*

[399] Red Trail Energy Subpart RR Monitoring, Reporting, and Verification (MRV) Plan. (2022). *https://www.epa.gov/system/files/documents/2022-04/rtemrvplan.pdf.*

[400] Technical Review of Subpart RR MRV Plan for Tundra SGS LLC at the Milton R. Young Station. (2022). *https://www.epa.gov/system/files/documents/2022-04/tsgsdecision.pdf.*

[401] Denbury. Detailed Pipeline and Ownership Information. (2022) *https://www.denbury.com/wp-content/uploads/2022/11/DEN-Pipeline-Schedule.pdf.*

[402] AP News. Officials mark start of CO_2 pipeline used for oil recovery. (2022) *https://apnews.com/article/business-texas-north-dakota-plano-25f1dbf9a924613a56827c1c83e4ba68.*

[403] Denbury. Detailed Pipeline and Ownership Information. (2022) *https://www.denbury.com/wp-content/uploads/2022/11/DEN-Pipeline-Schedule.pdf.*

[404] Tallgrass. Tallgrass to Capture and Sequester CO_2 Emissions from ADM Corn Processing Complex in Nebraska. (2022). *https://tallgrass.com/newsroom/press-releases/tallgrass-to-capture-and-sequester-co2-emissions-from-adm-corn-processing-complex-in-nebraska.*

[405] *https://boldnebraska.org/upcoming-meetings-understanding-the-new-tallgrass-carbon-pipeline-community-benefits-agreement/.*

cost projections and create additional CO_2 transport options for power plants that do CCS.

Moreover, pipeline projects have received funding under the IIJA to conduct front-end engineering and design (FEED) studies.[406] Carbon Solutions LLC received funding to conduct a FEED study for a commercial-scale pipeline to transport CO_2 in support of the Wyoming Trails Carbon Hub as part of a statewide pipeline system that would be capable of transporting up to 45 million metric tons of CO_2 per year from multiple sources. In addition, Howard Midstream Energy Partners LLC received funding to conduct a FEED study for a 965 km (600 mi) CO_2 pipeline system on the Gulf Coast that would be capable of moving at least 250 million metric tons of CO_2 annually and connecting carbon sources within 30 mi of the trunkline.

Other programs were created by the IIJA to facilitate the buildout of large pipelines to carry carbon dioxide from multiple sources. For example, the Carbon Dioxide Transportation Infrastructure Finance and Innovation Act (CIFIA) was incorporated into the IIJA and provided $2.1 billion to DOE to finance projects that build shared (*i.e.*, common carrier) transport infrastructure to move CO_2 from points of capture to conversion facilities and/or storage wells. The program offers direct loans, loan guarantees, and ''future growth grants'' to provide cash payments to specifically for eligible costs to build additional capacity for potential future demand.[407]

(2) Permitting and Rights of Way

The permitting process for CO_2 pipelines often involves a number of private, local, state, tribal, and/or Federal agencies. States and local governments are directly involved in siting and permitting proposed CO_2 pipeline projects. CO_2 pipeline siting and permitting authorities, landowner rights, and eminent domain laws are governed by the states and vary by state.

State laws determine pipeline siting and the process for developers to acquire rights-of-way needed to build. 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.[408] The permitting process for interstate pipelines may take longer than for intrastate pipelines. Whereas multiple state regulatory agencies would be involved in the permitting process for an interstate pipeline, only one primary state regulatory agency would be involved in the permitting process for an intrastate pipeline.

Most regulation of CO_2 pipeline siting and development is conducted at the state level, and under state specific regulatory regimes. As the interest in CO_2 pipelines has grown, states have taken steps to facilitate pipeline siting and construction. State level regulation related to CO_2 sequestration and transport is an very active area of legislation across states in all parts of the country, with many states seeking to facilitate pipeline siting and construction.[409] Many states, including Kentucky, Michigan, Montana, Arkansas, and Rhode Island, treat CO_2 pipeline operators as common carriers or public utilities.[410] This is an important classification in some jurisdictions where it may be required for pipelines seeking to exercise eminent domain.[411] Currently, 17 states explicitly allow CO_2 pipeline operators to exercise eminent domain authority for acquisition of CO_2 pipeline rights-of-way, should developers not secure them through negotiation with landowners.[412] Some states have recognized the need for a streamlined CO_2 pipeline permitting process when there are multiple layers of regulation and developed joint permit applications. Illinois, Louisiana, New York, and Pennsylvania have created a joint permitting form that allows applicants to file a single application for pipeline projects covering both state and federal permitting requirements.[413] Even in states without this streamlined process, pipeline developers can pursue required state permits concurrently with federal permits, NEPA review (as applicable), and the acquisition of rights-of-way.

Pipeline developers have been able to successfully secure the necessary rights-of way for CO_2 pipeline projects. For example, Summit Carbon Solutions, which has proposed to add more than 3,200 km (2,000 mi) of dedicated CO_2 pipeline in Iowa, Nebraska, North Dakota, South Dakota, and Minnesota, has stated that as of November 7, 2023, it had reached easement agreements with 2,100 landowners along the route.[414] As of February 23, 2024, Summit Carbon Solutions stated that it had acquired about 75 percent of the rights of way needed in Iowa, about 80 percent in North Dakota, about 75 percent in South Dakota, and about 89 percent in Minnesota. The company has successfully navigated hurdles, such as rerouting the pipelines in certain counties where necessary.[415 416] The EPA notes that this successful acquisition of right-of-way easements for thousands of miles of pipeline across five states has taken place in just the three years since the project launched in 2021.[417] In addition, the Citronelle Project, which was constructed in Alabama in 2011, successfully acquired rights-of-way through 9 miles of forested and commercial timber land and 3 miles of emergent shrub and forested wetlands. The Citronelle Project was able to attain rights-of-way through the habitat of an endangered species by mitigating potential environmental

[406] Office of Fossil Energy and Carbon Management. ''Project Selections for FOA 2730: Carbon Dioxide Transport Engineering and Design (Round 1).'' *https://www.energy.gov/fecm/project-selections-foa-2730-carbon-dioxide-transport-engineering-and-design-round-1.*

[407] *https://www.energy.gov/lpo/carbon-dioxide-transportation-infrastructure.*

[408] Congressional Research Service.2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June 3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[409] Great Plains Institute State Legislative Tracker 2023. Carbon Management State Legislative Program Tracker. *https://www.quorum.us/spreadsheet/external/fVGjsTvwyeWkIqVlNmoq/?mc_cid=915706f2bc&.*

[410] National Association of Regulatory Utility Commissioners (NARUC). (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[411] Martin Lockman. *Permitting CO_2 Pipelines.* Sabin Center for Climate Change Law (2023). *https://scholarship.law.columbia.edu/cgi/viewcontent.cgi?article=1208&context=sabin_climate_change.*

[412] The 17 states are: Arizona, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Montana, New Mexico, North Carolina, North Dakota, Pennsylvania, South Dakota, Texas, and Wyoming. National Association of Regulatory Utility Commissioners (NARUC). (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[413] Martin Lockman. *Permitting CO_2 Pipelines.* Sabin Center for Climate Change Law (Sept. 2023). *https://scholarship.law.columbia.edu/cgi/viewcontent.cgi?article=1208&context=sabin_climate_change.*

[414] South Dakota Public Broadcasting. ''Summit reaches land deals on more than half of CO_2 pipeline route.'' (2022). *https://listen.sdpb.org/business-economics/2022-11-08/summit-reaches-land-deals-on-more-than-half-of-co2-pipeline-route.*

[415] Summit CEO: CO2 Pipeline's Time is Now. (2024). *https://www.dtnpf.com/agriculture/web/ag/news/business-inputs/article/2024/02/23/summit-ceo-blank-says-company-toward.*

[416] Summit Carbon Solutions. Summit Carbon Solutions Signs 80 Percent of North Dakota Landowners. (2023). *https://summitcarbonsolutions.com/summit-carbon-solutions-signs-80-percent-of-north-dakota-landowners/.*

[417] Summit Carbon Solutions. Summit Carbon Solutions Announces Progress on Carbon Capture and Storage Project. (2022). *https://summitcarbonsolutions.com/summit-carbon-solutions-announces-progress-on-carbon-capture-and-storage-project/.*

impacts.[418] Even projects that require rights-of-way across multiple ownership regimes including state, private, and federally owned land have been successfully developed. The 170 km (105 mile) Cedar Creek Anticline CO_2 pipeline owned by Denbury required easements for approximately 10 km (6.2 mi) to cross state school trust lands in Montana, 27 km (17 mi) across Federal land and the remaining miles across private lands.[419] [420] The pipeline was completed in 2021.[421]

Federal actions (*e.g.*, funding a CCS project) must generally comply with NEPA, which often requires that an environmental assessment (EA) or environmental impact statement (EIS) be conducted to consider environmental impacts of the proposed action, including consideration of reasonable alternatives.[422] An EA determines whether or not a Federal action has the potential to cause significant environmental effects. Each Federal agency has adopted its own NEPA procedures for the preparation of EAs.[423] If the agency determines that the action will not have significant environmental impacts, the agency will issue a Finding of No Significant Impact (FONSI). Some projects may also be ''categorically excluded'' from a detailed environmental analysis when the Federal action normally does not have a significant effect on the human environment. Federal agencies prepare an EIS if a proposed Federal action is determined to significantly affect the quality of the human environment. The regulatory requirements for an EIS are more detailed and rigorous than the requirements for an EA. The determination of the level of NEPA review depends on the potential for significant environmental impacts considering the whole project (*e.g.*, crossings of sensitive habitats, cultural resources, wetlands, public safety concerns). Consequently, whether a pipeline project is covered by NEPA and the associated permitting timelines may vary depending on site characteristics (*e.g.*, pipeline length, whether a project crosses a water of the U.S.) and funding source. Pipelines through Bureau of Land Management (BLM) land, U.S. Forest Service (USFS) land, or other Federal land would be subject to NEPA. To ensure that agencies conduct NEPA reviews as efficiently and expeditiously as practicable, the Fiscal Responsibility Act [424] amendments to NEPA established deadlines for the preparation of environmental assessments and environmental impact statements. Environmental assessments must be completed within 1 year and environmental impact statements must be completed within 2 years [425] A lead agency that determines it is not able to meet the deadline may extend the deadline, in consultation with the applicant, to establish a new deadline that provides only so much additional time as is necessary to complete such environmental impact statement or environmental assessment.[426]

As discussed above, it is anticipated that most EGUs would need shorter, intrastate pipeline segments. For example, ADM's Decatur, Illinois, pipeline, which spans 1.9 km (1.18 miles), was constructed after Decatur was selected for the DOE Phase 1 research and development grants in October 2009.[427] Construction of the CO_2 compression, dehydration, and pipeline facilities began in July 2011 and was completed in June 2013.[428] The ADM project required only an EA. Additionally, Air Products operates a large-scale system to capture CO_2 from two steam methane reformers located within the Valero Refinery in Port Arthur, Texas. The recovered and purified CO_2 is delivered by pipeline for use in enhanced oil recovery operations.[429] This 12-mile pipeline required only an EA.[430] Conversely, the Petra Nova project in Texas required an EIS to evaluate the potential environmental impacts associated with DOE's proposed action of providing financial assistance for the project. This EIS addressed potential impacts from both the associated 131 km (81 mile) pipeline and other aspects of the larger CCS system, including the post-combustion CO_2.[431] For Petra Nova, a notice of intent to issue an EIS was published on November 14, 2011, and the record of decision was issued less than 2 years later, on May 23, 2013.[432] Construction of the CO_2 pipeline for Petra Nova from the W.A. Parish Power Plant to the West Ranch Oilfield in Jackson County, TX began in July 2014 and was completed in July 2016.[433]

Compliance with section 7 of the Endangered Species Act related to Federal agency consultation and biological assessment is also required for projects on Federal lands. Specifically, the Endangered Species Act requires consultation with the Department of Interior's Fish and Wildlife Service and Department of Commerce's NOAA Fisheries, in order to avoid or mitigate impacts to any threatened or endangered species and their habitats.[434] This agency consultation process and biological assessment are generally conducted during preparation of the NEPA documentation (EIS or EA) for the Federal project and generally within the regulatory timeframes for environmental assessment or environmental impact statement preparation. Consequently, the EPA does not anticipate that compliance with the Endangered Species Act will change the anticipated timeline for most projects.

The EPA notes that the Fixing America's Surface Transportation Act (FAST Act) is also relevant to CCS projects and pipelines. Title 41 of this Act (42 U.S.C. 4370m *et seq.*), referred to as ''FAST–41,'' created a new

[418] SECARB. (2021). Final Project Report—SECARB Phase III, September 2021. *https://www.osti.gov/servlets/purl/1823250.*

[419] Great Falls Tribune. Texas company plans 110-mile CO_2 pipeline to enhance Montana oil recovery. (2018). *https://www.greatfallstribune.com/story/news/2018/10/09/texas-company-plans-co-2-pipeline-injection-free-montana-oil/1577657002/.*

[420] U.S. D.O.I B.L.M. Denbury-Green Pipeline-MT, LLC, Denbury Onshore, LLC Cedar Creek Anticline CO_2 Pipeline and EOR Development Project Scoping Report. *https://eplanning.blm.gov/public_projects/nepa/89883/137194/167548/BLM_Denbury_Projects_Scoping_Report_March2018.pdf.*

[421] AP News. Officials mark start of CO_2 pipeline used for oil recovery. (2022) *https://apnews.com/article/business-texas-north-dakota-plano-25f1dbf9a924613a56827c1c83e4ba68.*

[422] Council on Environmental Quality. (2024). CEQ NEPA Regulations. *https://ceq.doe.gov/laws-regulations/regulations.html.*

[423] Council of Environmental Quality. (2023). Agency NEPA Implementing Procedures. *https://ceq.doe.gov/laws-regulations/agency_implementing_procedures.html.*

[424] Public Law 118–5 (June 3, 2023).

[425] NEPA Sec. 107(g)(1); 42 U.S.C. 4336a(g)(1).

[426] NEPA sec. 107(g)(2); 42 U.S.C. 4336a(g)(2).

[427] Massachusetts Institute of Technology. (2014). Decatur Fact Sheet: Carbon Dioxide Capture and Storage Project. *https://sequestration.mit.edu/tools/projects/decatur.html.*

[428] NETL. ''CO2 Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone.'' Award #DE–FE0001547. *https://www.usaspending.gov/award/ASST_NON_DEFE0001547_8900.*

[429] Air Products. Carbon Capture. *https://www.airproducts.com/company/innovation/carbon-capture.*

[430] Department of Energy. (2011). Final Environmental Assessment for Air Products and Chemicals, Inc. Recovery Act: Demonstration of CO_2 Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large Scale Hydrogen Production. *https://netl.doe.gov/sites/default/files/environmental-assessments/20110622_APCI_PtA_CO2_FEA.pdf.*

[431] Department of Energy, Office of NEPA Policy and Compliance. (2013). EIS–0473: Record of Decision. *https://www.energy.gov/nepa/articles/eis-0473-record-decision.*

[432] Department of Energy. (2017). Petra Nova W.A. Parish Project. *https://www.energy.gov/fecm/petra-nova-wa-parish-project.*

[433] Kennedy, Greg. (2020). ''W.A. Parish Post Combustion CO_2 Capture and Sequestration Demonstration Project.'' Final Technical Report. *https://www.osti.gov/biblio/1608572/.*

[434] CEQ. (2021). ''Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration.'' *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

governance structure, set of procedures, and funding authorities to improve the Federal environmental review and authorization process for covered infrastructure projects.[435] The Utilizing Significant Emissions with Innovative Technologies (USE IT) Act, among other actions, clarified that CCS projects and CO_2 pipelines are eligible for this more predictable and transparent review process.[436] FAST–41 created the Federal Permitting Improvement Steering Council (Permitting Council), composed of agency Deputy Secretary-level members and chaired by an Executive Director appointed by the President. FAST–41 establishes procedures that standardize interagency consultation and coordination practices. FAST–41 codifies into law the use of the Permitting Dashboard[437] to track project timelines, including qualifying actions that must be taken by the EPA and other Federal agencies. Project sponsor participation in FAST–41 is voluntary.[438]

Community engagement also plays a role in the safe operation and construction of CO_2 pipelines. These efforts can be supported using the CCS Pipeline Route Planning Database that was developed by NETL, a public resource designed to support pipeline routing decisions and increase transportation safety.[439] The database includes state-specific regulations and restrictions, energy and social justice factors, land use requirements, existing infrastructure, and areas of potential risk. The database produces weighted values ranging from zero to one, where zero represents acceptable areas for pipeline placement and one represents areas that should be avoided.[440] The database will be a key input for the CCS Pipeline Route Planning Tool under development by NETL.[441] The purpose of the siting tool is to aid pipeline routing decisions and facilitate avoidance of areas that would pose permitting challenges.

In sum, the permitting process for CO_2 pipelines often involves private, local, state, tribal, and/or Federal agencies, and permitting timelines may vary depending on site characteristics. Projects that opt in to the FAST–41 process are eligible for a more transparent and predictable review process. EGUs can generally proceed to obtain permits and rights-of-way simultaneously, and the EPA anticipates that, in total, the permitting process would only take around 2.5 years for pipelines that only need an EA, with a possible additional year if the project requires an EIS (see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional information). This is consistent with the anticipated timelines for CCS discussed in section VII.C.1.a.i(E). Furthermore, the EPA notes that there is over 60 years of experience in the CO_2 pipeline industry designing, permitting, building and operating CO_2 pipelines, and that this expertise can be applied to the CO_2 pipelines that would be constructed to connect to sequestration sites and units.

As discussed above in section VII.C.1.a.i.(C)(1)(a), the core of the EPA's analysis of pipeline feasibility focuses on units located within 100 km (62 miles) of potential deep saline sequestration formations. The EPA notes that the majority (80 percent) of the coal-fired steam generating capacity with planned operation during or after 2039 is located within 100 km (62 miles) of the nearest potential deep saline sequestration site. For these sources, as explained, units would be required only to build relatively short pipelines, and such buildout would be feasible within the required timeframe. For the capacity that is more than 100 km (62 miles) away from sequestration, building a pipeline may become more complex. Almost all (98 percent) of this capacity's closest sequestration site is located outside state boundaries, and access to the nearest sequestration site would require building an interstate pipeline and coordinating with multiple state authorities for permitting purposes. Conversely, for capacity where the distance to the nearest potential sequestration site is less than 100 km (62 miles), only about 19 percent would require the associated pipeline to cross state boundaries. Therefore, the EPA believes that distance to the nearest sequestration site is a useful proxy for considerations related to the complexity of pipeline construction and how long it will take to build a pipeline.

A unit that is located more than 100 km away from sequestration may face complexities in pipeline construction, including additional permitting hurdles, difficulties in obtaining the necessary rights of way over such a distance, or other considerations, that may make it unreasonable for that unit to meet the compliance schedule that is generally reasonable for sources in the subcategory as a whole. Pursuant to the RULOF provisions of 40 CFR 60.2a(e)–(h), if a state can demonstrate that there is a fundamental difference between the information relevant to a particular affected EGU and the information the EPA considered in determining the compliance deadline for sources in the long-term subcategory, and that this difference makes it unreasonable for the EGU to meet the compliance deadline, a longer compliance schedule may be warranted. The EPA does not believe that the fact that a pipeline crosses state boundaries standing alone is sufficient to show that an extended timeframe would be appropriate—many such pipelines could be reasonably accomplished in the required timeframe. Rather, it is the confluence of factors, including that a pipeline crosses state boundaries, along with others that may make RULOF appropriate.

(3) Security of CO_2 Transport

As part of its analysis, the EPA also considered the safety of CO_2 pipelines. The safety of existing and new CO_2 pipelines that transport CO_2 in a supercritical state is regulated by PHMSA. These regulations include standards related to pipeline design, pipeline construction and testing, pipeline operations and maintenance, operator reporting requirements, operator qualifications, corrosion control and pipeline integrity management, incident reporting and response, and public awareness and communications. PHMSA has regulatory authority to conduct inspections of supercritical CO_2 pipeline operations and issue notices to operators in the event of operator noncompliance with regulatory requirements.[442]

CO_2 pipelines have been operating safely for more than 60 years. In the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines with zero incidents involving fatalities.[443] PHMSA reported a total of

[435] Federal Permitting Improvement Steering Council. (2022). FAST–41 Fact Sheet. *https://www.permits.performance.gov/documentation/fast-41-fact-sheet.*

[436] Galford, Chris. USE IT carbon capture bill becomes law, incentivizing development and deployment. (2020). *https://dailyenergyinsider.com/news/28522-use-it-carbon-capture-bill-becomes-law-incentivizing-development-and-deployment/.*

[437] Permitting Dashboard Federal Infrastructure Projects. *https://permits.performance.gov/.*

[438] EPA. "FAST–41 Coordination." (2023). *https://www.epa.gov/sustainability/fast-41-coordination.*

[439] "CCS Pipeline Route Planning Database V1—EDX." *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[440] "CCS Pipeline Route Planning Database V1—EDX." *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[441] Department of Energy. "CCS Pipeline Route Planning Database V1—EDX." *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[442] See generally 49 CFR 190–199.

[443] Congressional Research Service. 2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June

102 CO_2 pipeline incidents between 2003 and 2022, with one injury (requiring in-patient hospitalization) and zero fatalities.[444]

As noted previously in this preamble, a significant CO_2 pipeline rupture occurred in 2020 in Satartia, Mississippi, following heavy rains that resulted in a landslide. Although no one required in-patient hospitalization as a result of this incident, 45 people received treatment at local emergency rooms after the incident and 200 hundred residents were evacuated. Typically, when CO_2 is released into the open air, it vaporizes into a heavier-than-air gas and dissipates. During the Satartia incident, however, unique atmospheric conditions and the topographical features of the area delayed this dissipation. As a result, residents were exposed to high concentrations of CO_2 in the air after the rupture. Furthermore, local emergency responders were not informed by the operator of the rupture and the nature of the unique safety risks of the CO_2 pipeline.[445]

PHMSA initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of supercritical CO_2 pipelines following the investigation into the CO_2 pipeline failure in Satartia.[446] PHMSA submitted the associated Notice of Proposed Rulemaking to the White House Office of Management and Budget on February 1, 2024 for pre-publication review.[447] Following the Satartia incident, PHMSA also issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice) to the operator related to probable violations of Federal pipeline safety regulations. The Notice was ultimately resolved through a Consent Agreement between PHMSA and the operator that includes the assessment of civil penalties and identifies actions for the operator to take to address the alleged violations and risk conditions.[448] PHMSA has further issued an updated nationwide advisory bulletin to all pipeline operators and solicited research proposals to strengthen CO_2 pipeline safety.[449] Given the Federal and state regulation of CO_2 pipelines and the steps that PHMSA is taking to further improve pipeline safety, the EPA believes CO_2 can be safely transported by pipeline.

Certain states have authority delegated from the U.S. Department of Transportation to conduct safety inspections and enforce state and Federal pipeline safety regulations for intrastate CO_2 pipelines.[450] [451] [452] PHMSA's state partners employ about 70 percent of all pipeline inspectors, which covers more than 80 percent of regulated pipelines.[453] Federal law requires certified state authorities to adopt safety standards at least as stringent as the Federal standards.[454] Further, there are required steps that CO_2 pipeline operators must take to ensure pipelines are operated safely under PHMSA standards and related state standards, such as the use of pressure monitors to detect leaks or initiate shut-off valves, and annual reporting on operations, structural integrity assessments, and inspections.[455] These CO_2 pipeline controls and PHMSA standards are designed to ensure that captured CO_2 will be securely conveyed to a sequestration site.

(4) Comments Received on CO_2 Transport and Responses

The EPA received comments on CO_2 transport, including CO_2 pipelines. Those comments, and the EPA's responses, are as follows.

Comment: Some commenters identified challenges to the deployment of a national, interstate CO_2 pipeline network. In particular, those commenters discussed the experience faced by long (*e.g.*, over 1,000 miles) CO_2 pipelines seeking permitting and right-of-way access in Midwest states including Iowa and North Dakota. Commenters claimed those challenges make CCS as BSER infeasible. Some commenters argued that the existing CO_2 pipeline capacity is not adequate to meet potential demand caused by this rule and that the ability of the network to grow and meet future potential demand is hindered by significant public opposition.

Response: The EPA acknowledges the challenges that some large multi-state pipeline projects have faced, but does not agree that those experiences show that the BSER is not adequately demonstrated or that the standards finalized in these actions are not achievable. As detailed in the preceding subsections of the preamble, the BSER is not premised on the buildout of a national, trunkline CO_2 pipeline network. Most coal-fired steam generating units are in relatively close proximity to geologic storage, and those shorter pipelines would not likely be as challenging to permit and build as demonstrated by the examples of smaller pipeline discussed above.

The EPA acknowledges that some larger trunkline CO_2 pipeline projects, specifically the Heartland Greenway project, have recently been delayed or canceled. However, many projects are still moving forward and several major projects have recently been announced to expand the CO_2 pipeline network across the United States. The EPA notes that there are often opportunities to reroute pipelines to minimize permitting challenges and landowner concerns. For example, Summit Carbon Solutions changed their planned pipeline route in North Dakota after their initial permit was denied, leading to successful acquisition of rights of way.[456] Additionally, Tallgrass, which

3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[444] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[445] Failure Investigation Report—Denbury Gulf Coast Pipeline, May 2022. *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf.*

[446] PHMSA. (2022). "PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak." *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[447] Columbia Law School. (2024). PHMSA Advances CO2 Pipeline Safety Regulations. *https://climate.law.columbia.edu/content/phmsa-advances-co2-pipeline-safety-regulations.*

[448] Department of Transportation. (2023). Consent Order, Denbury Gulf Coast Pipelines, LLC, CPF No. 4–2022–017–NOPV *https://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_42022017NOPV.html?nocache=7208.*

[449] Ibid.

[450] New Mexico Public Regulation Commission. 2023. Transportation Pipeline Safety. New Mexico Public Regulation Commission, Bureau of Pipeline Safety. *https://www.nm-prc.org/transportation/pipeline-safety.*

[451] Texas Railroad Commission. 2023. *Oversight & Safety Division.* Texas Railroad Commission. *https://www.rrc.texas.gov/about-us/organization-and-activities/rrc-divisions/oversight-safety-division.*

[452] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[453] PHMSA. (2023). "PHMSA Issues Letters to Wolf Carbon, Summit, and Navigator Clarifying Federal, State, and Local Government Pipeline Authorities." *https://www.phmsa.dot.gov/news/phmsa-issues-letters-wolf-carbon-summit-and-navigator-clarifying-federal-state-and-local.*

[454] PHMSA, "PHMSA Issues Letters to Wolf Carbon, Summit, and Navigator Clarifying Federal, State, and Local Government Pipeline Authorities." 2023. *https://www.phmsa.dot.gov/news/phmsa-issues-letters-wolf-carbon-summit-and-navigator-clarifying-federal-state-and-local.*

[455] Carbon Capture Coalition. "PHMSA/Pipeline Safety Fact Sheet," November 2023. *https://carboncapturecoalition.org/wp-content/uploads/2023/11/Pipeline-Safety-Fact-Sheet.pdf.*

[456] Summit Carbon Solutions. Summit Carbon Solutions Signs 80 Percent of North Dakota

Continued

is planning to convert a 630 km (392 mile) natural gas pipeline to carry CO_2, announced that they had reach a community benefits agreement, in which certain organizations have agreed not to oppose the pipeline project while Tallgrass has agreed to terms such as contributing funds to first responders along the pipeline route and providing royalty checks to landowners.[457] See section VII.C.1.a.i(C)(1)(d) for additional discussion of planned CO_2 pipelines. While access to larger trunkline projects would not be required for most EGUs, at least some larger trunkline projects are likely to be constructed, which would increase opportunities for connecting to pipeline networks.

Comment: Some commenters disagreed with the modeling assumption that 100 km is a typical pipeline distance. The commenters asserted that there is data showing the actual locations of the power plants affected by the rule, and the required pipeline distance is not always 100 km.

Response: The EPA acknowledges that the physical locations of EGUs and the physical locations of carbon sequestration capacity and corresponding pipeline distance will not be 100 km in all cases. As discussed previously in section VII.C.1.a.i(C)(1)(a), the EPA modeled the unique approximate distance from each existing coal-fired steam generating capacity with planned operation during or after 2039 to the nearest potential saline sequestration site, and found that the majority (80 percent) is within 100 km (62 miles) of potential saline sequestration sites, and another 11 percent is within 160 km (100 miles).[458] Furthermore, the EPA disagrees with the comments suggesting that the use of 100 km is an inappropriate economic modeling assumption. The 100 km assumption was not meant to encompass the physical location of every potentially affected EGU. The 100 km assumption is intended as an economic modeling assumption and is based on similar assumptions applied in NETL studies used to estimate CO_2 transport costs. The EPA carefully reviewed the assumptions on which the NETL transport cost estimates are based and continues to find them reasonable. The NETL studies referenced in section VII.C.1.a.ii based transport costs on a generic 100 km (62 mile) pipeline and a generic 80 km pipeline.[459] For most EGUs, the necessary pipeline distance is anticipated to be less than 100 km and therefore the associated costs could also be lower than these assumptions. Other published economic models applying different assumptions have also reached the conclusion that CO_2 transport and sequestration are adequately demonstrated.[460]

Comment: Commenters also stated that the permitting and construction processes can be time-consuming.

Response: The EPA acknowledges building CO_2 pipelines requires capital expenditure and acknowledges that the timeline for siting, engineering design, permitting, and construction of CO_2 pipelines depends on factors including the pipeline capacity and pipeline length, whether the pipeline route is intrastate or interstate, and the specifics of the state pipeline regulator's regulatory requirements. In the BSER analysis, individual EGUs that are subject to carbon capture requirements are assumed to take a point-to-point approach to CO_2 transport and sequestration. These smaller-scale projects require less capital and may present less complexity than larger projects. The EPA considers the timeline to permit and install such pipelines in section VII.C.1.a.i(E) of the preamble, and has determined that a compliance date of January 1, 2032 allows for a sufficient amount of time.

Comment: Some commenters expressed significant concerns about the safety of CO_2 pipelines following the CO_2 pipeline failure in Satartia, Mississippi in 2020.

Response: For a discussion of the safety of CO_2 pipelines and the Satartia pipeline failure, see section VII.C.1.a.i(C)(3). The EPA believes that the framework of Federal and state regulation of CO_2 pipelines and the steps that PHMSA is taking to further improve pipeline safety, is sufficient to ensure CO_2 can be safely transported by pipeline.

(D) Geologic Sequestration of CO_2

The EPA is finalizing its determination that geologic sequestration (*i.e.*, the long-term containment of a CO_2 stream in subsurface geologic formations) is adequately demonstrated. In this section, we provide an overview of the availability of sequestration sites in the U.S., discuss how geologic sequestration of CO_2 is well proven and broadly available throughout the U.S, explain the effectiveness of sequestration, discuss the regulatory framework for UIC wells, and discuss the timing of permitting for sequestration sites. We then provide a summary of key comments received concerning geologic sequestration and our responses to those comments.

(1) Sequestration Sites for Coal-Fired Power Plants Subject to CCS Requirements

(a) Broad Availability of Sequestration

Sequestration is broadly available in the United States, which makes clear that it is adequately demonstrated. By far the most widely available and well understood type of sequestration is that in deep saline formations. These formations are common in the U.S. These formations are numerous and only a small subset of the existing saline storage capacity would be required to store the CO_2 from EGUs. Many projects are in the process of completing thorough subsurface studies of these deep saline formations to determine their suitability for regional-scale storage. Furthermore, sequestration formations could also include unmineable coal seams and oil and gas reservoirs. CO_2 may be stored in oil and gas reservoirs in association with EOR and enhanced gas recovery (EGR) technologies, collectively referred to as enhanced recovery (ER), which include the injection of CO_2 in oil and gas reservoirs to increase production. ER is a technology that has been used for decades in states across the U.S.[461]

Geologic sequestration is based on a demonstrated understanding of the trapping and containment processes that retain CO_2 in the subsurface. The presence of a low permeability seal is an important component of demonstrating secure geologic sequestration. Analyses of the potential availability of geologic sequestration capacity in the United States have been conducted by DOE,

Landowners. (2023). *https://summitcarbonsolutions.com/summit-carbon-solutions-signs-80-percent-of-north-dakota-landowners/.*

[457] Hammel, Paul. (2024). Pipeline company, Nebraska environmental group strike unique 'community benefits' agreement. *https://www.desmoinesregister.com/story/tech/science/environment/2024/04/11/nebraska-environmentalist-forge-peace-pact-with-pipeline-company/73282852007/.*

[458] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[459] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[460] Ogland-Hand, Jonathan D. et. al. 2022. *Screening for Geologic Sequestration of CO_2: A Comparison Between SCO2TPRO and the FE/NETL CO_2 Saline Storage Cost Model.* International Journal of Greenhouse Gas Control, Volume 114, February 2022, 103557. *https://www.sciencedirect.com/science/article/pii/S175058362100308X.*

[461] NETL. (2010). Carbon Dioxide Enhanced Oil Recovery. *https://www.netl.doe.gov/sites/default/files/netl-file/co2_eor_primer.pdf.*

and the U.S. Geological Survey (USGS) has also undertaken a comprehensive assessment of geologic sequestration resources in the United States.[462 463] Geologic sequestration potential for CO_2 is widespread and available throughout the United States. Nearly every state in the United States has or is in close proximity to formations with geologic sequestration potential, including areas offshore. There have been numerous efforts demonstrating successful geologic sequestration projects in the United States and overseas, and the United States has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. Moreover, the amount of storage potential can readily accommodate the amount of CO_2 for which sequestration could be expected under this final rule.

The EPA has performed a geographic availability analysis in which the Agency examined areas of the U.S. with sequestration potential in deep saline formations, unmineable coal seams, and oil and gas reservoirs; information on existing and probable, planned or under study CO_2 pipelines; and areas within a 100 km (62-mile) area of potential sequestration sites. This availability analysis is based on resources from the DOE, the USGS, and the EPA. The distance of 100 km is consistent with the assumptions underlying the NETL cost estimates for transporting CO_2 by pipeline. The scoping assessment by the EPA found that at least 37 states have geologic characteristics that are amenable to deep saline sequestration, and an additional 6 states are within 100 kilometers of potentially amenable deep saline formations in either onshore or offshore locations. Of the 7 states that are further than 100 km (62 mi) of onshore or offshore storage potential in deep saline formations, only New Hampshire has coal EGUs that were assumed to be in operation after 2039, with a total capacity of 534 MW. However, the EPA notes that as of March 27, 2024, the last coal-fired steam EGUs in New Hampshire announced that they would cease operation by 2028.[464] Therefore, the EPA anticipates that there will no existing coal-fired steam EGUs located in states that are further than 100 km (62 mi) of potential geologic sequestration sites. Furthermore, as described in section VII.C.1.a.i(C), new EGUs would have the ability to consider proximity and access to geologic sequestration sites or CO_2 pipelines in the siting process.

The DOE and the United States Geological Survey (USGS) have independently conducted preliminary analyses of the availability and potential CO_2 sequestration resources in the United States. The DOE estimates are compiled in the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) using volumetric models and are published in its Carbon Utilization and Sequestration Atlas (NETL Atlas). The DOE estimates that areas of the United States with appropriate geology have a sequestration potential of at least 2,400 billion to over 21,000 billion metric tons of CO_2 in deep saline formations, unmineable coal seams, and oil and gas reservoirs. The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential across the United States. With respect to deep saline formations, the DOE estimates a sequestration potential of at least 2,200 billion metric tons of CO_2 in these formations in the United States. The EPA estimates that the CO_2 emissions reductions for this rule (which is similar to the amount of CO_2 may be sequestered under this rule) are estimated in the range of 1.3 to 1.4 billion metric tons over the 2028 to 2047 timeframe.[465] This volume of sequestered CO_2 is less than a tenth of a percent of the storage capacity in deep saline formations estimated to be available by DOE.

Unmineable coal seams offer another potential option for geologic sequestration of CO_2. Enhanced coalbed methane recovery is the process of injecting and storing CO_2 in unmineable coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively "locks" the CO_2 to the coal, where it remains stored. States with the potential for sequestration in unmineable coal seams include Iowa and Missouri, which have little to no saline sequestration potential and have existing coal-fired EGUs. Unmineable coal seams have a sequestration potential of at least 54 billion metric tons of CO_2, or 2 percent of total potential in the United States, and are located in 22 states.

The potential for CO_2 sequestration in unmineable coal seams has been demonstrated in small-scale demonstration projects, including the Allison Unit pilot project in New Mexico, which injected a total of 270,000 tons of CO_2 over a 6-year period (1995–2001). Further, DOE Regional Carbon Sequestration Partnership projects have injected CO_2 volumes in unmineable coal seams ranging from 90 tons to 16,700 tons, and completed site characterization, injection, and post-injection monitoring for sites. DOE has included unmineable coal seams in the NETL Atlas. One study estimated that in the United States, 86.16 billion tons of CO_2 could be permanently stored in unmineable coal seams.[466] Although the large-scale injection of CO_2 in coal seams can lead to swelling of coal, the literature also suggests that there are available technologies and techniques to compensate for the resulting reduction in injectivity. Further, the reduced injectivity can be anticipated and accommodated in sizing and characterizing prospective sequestration sites.

Depleted oil and gas reservoirs present additional potential for geologic sequestration. The reservoir characteristics of developed fields are well known as a result of exploration and many years of hydrocarbon production and, in many areas, infrastructure already exists which could be evaluated for conversion to CO_2 transportation and sequestration service. Other types of geologic formations such as organic rich shale and basalt may also have the ability to store CO_2, and DOE is continuing to evaluate their potential sequestration capacity and efficacy.

(b) Inventory of Coal-Fired Power Plants That Are Candidates for CCS

Sequestration potential as it relates to distance from existing coal-fired steam generating units is a key part of the EPA's regular power sector modeling, using data from DOE/NETL studies.[467] As discussed in section VII.C.1.a.i(D)(1)(a), the availability

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[462] U.S. DOE NETL. (2015). Carbon Storage Atlas, Fifth Edition, September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.*

[463] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). National assessment of geologic carbon dioxide storage resources—Summary: U.S. Geological Survey Factsheet 2013–3020. *http://pubs.usgs.gov/fs/2013/3020/.*

[464] Vickers, Clayton. (2024). "Last coal plants in New England to close; renewables take their place." *https://thehill.com/policy/energy-environment/4560375-new-hampshire-coal-plants-closing/.*

[465] For detailed information on the estimated emissions reductions from this rule, see section 3 of the RIA, available in the rulemaking docket.

[466] Godec, Koperna, and Gale. (2014). "CO_2-ECBM: A Review of its Status and Global Potential", Energy Procedia, Volume 63. *https://doi.org/10.1016/j.egypro.2014.11.619.*

[467] For details, please see Chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

analysis shows that of the coal-fired steam generating capacity with planned operation during or after 2039, more than 50 percent is less than 32 km (20 miles) from potential deep saline sequestration sites, 73 percent is located within 50 km (31 miles), 80 percent is located within 100 km (62 miles), and 91 percent is within 160 km (100 miles).[468]

(2) Geologic Sequestration of CO_2 Is Adequately Demonstrated

Geologic sequestration is based on a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. Existing project and regulatory experience, along with other information, indicate that geologic sequestration is a viable long-term CO_2 sequestration option. As discussed in this section, there are many examples of projects successfully injecting and containing CO_2 in the subsurface.

Research conducted through the Department of Energy's Regional Carbon Sequestration Partnerships has demonstrated geologic sequestration through a series of field research projects that increased in scale over time, injecting more than 12 million tons of CO_2 with no indications of negative impacts to either human health or the environment.[469] Building on this experience, DOE launched the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative in 2016 to demonstrate how knowledge from the Regional Carbon Sequestration Partnerships can be applied to commercial-scale safe storage. This initiative is furthering the development and refinement of technologies and techniques critical to the characterization of sites with the potential to sequester greater than 50 million tons of CO_2.[470] In Phase I of CarbonSAFE, thirteen projects conducted economic feasibility analyses, collected, analyzed, and modeled extensive regional data, evaluated multiple storage sites and infrastructure, and evaluated business plans. Six projects were funded for Phase II which involves storage complex feasibility studies. These projects evaluate initial reservoir characteristics to determine if the reservoir is suitable for geologic sequestration sites of more than 50 million tons of CO_2, address technical and non-technical challenges that may arise, develop a risk assessment and CO_2 management strategy for the project; and assist with the validation of existing tools. Five projects have been funded for CarbonSAFE Phase III and are currently performing site characterization and permitting.

The EPA notes that, while only sequestration facilities with Federal funding are currently operational in the United States, multiple commercial sequestration facilities, other than those funded under EPAct05, are in construction or advanced development, with some scheduled to open for operation as early as 2025.[471] These facilities have proposed sequestration capacities ranging from 0.03 to 6 million tons of CO_2 per year. The Great Plains Synfuel Plant currently captures 2 million metric tons of CO_2 per year, which is exported to Canada for use in EOR; a planned addition of sequestration in a saline formation for this facility is expected to increase the amount of CO_2 captured and sequestered (through both geologic sequestration and EOR) to 3.5 million metric tons of CO_2 per year.[472] The EPA and states with approved UIC Class VI programs (including Wyoming, North Dakota, and Louisiana) are currently reviewing UIC Class VI geologic sequestration well permit applications for proposed sequestration sites in fourteen states.[473] [474] [475] As of March 15, 2024, 44 projects with 130 injection wells are under review by the EPA.[476]

Currently, there are planned geologic sequestration facilities across the United States in various phases of development, construction, and operation. The Wyoming Department of Environmental Quality issued three UIC Class VI permits in December 2023 to Frontier Carbon Solutions. The Frontier Carbon Solutions project will sequester 5 million metric tons of CO_2/year.[477] Additionally, UIC Class VI permit applications have been submitted to the Wyoming Department of Environmental Quality for a proposed Eastern Wyoming Sequestration Hub project that would sequester up to 3 million metric tons of CO_2/year.[478] The North Dakota Oil and Gas Division has issued UIC Class VI permits to 6 sequestration projects that collectively will sequester 18 million metric tons of CO_2/year.[479] Since 2014, the EPA has issued two UIC Class VI permits to Archer Daniels Midland (ADM) in Decatur, Illinois, which authorize the injection of up to 7 million metric tons of CO_2. One of the AMD wells is in the injection phase while the other is in the post-injection phase. In January 2024, the EPA issued two UIC Class VI permits to Wabash Carbon Services LLC for a project that will sequester up to 1.67 million metric tons of CO_2/year over an injection period of 12 years.[480] In December 2023, the EPA released for public comment four UIC Class VI draft permits for the Carbon TerraVault projects, to be located in California.[481] These projects propose to sequester CO_2 captured from multiple different sources in California including a hydrogen plant, direct air capture, and pre-combustion gas treatment. TerraVault plans to inject 1.46 million metric tons of CO_2 annually into the four proposed wells over a 26-year injection period with a total potential capacity of 191 million metric tons.[482] [483] One of the proposed wells is

[468] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[469] Regional Sequestration Partnership Overview. *https://netl.doe.gov/carbon-management/carbon-storage/RCSP.*

[470] National Energy Technology Laboratory. CarbonSAFE Initiative. *https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe.*

[471] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[472] Basin Electric Power Cooperative. (2021). "Great Plains Synfuels Plant Potential to Be Largest Coal-Based Carbon Capture and Storage Project to Use Geologic Storage". *https://www.basinelectric.com/News-Center/news-releases/Great-Plains-Synfuels-Plant-potential-to-be-largest-coal-based-carbon-capture-and-storage-project-to-use-geologic-storage.*

[473] UIC regulations for Class VI wells authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water. The major components to be included in UIC Class VI permits are detailed further in section VII.C.1.a.i(D)(4).

[474] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 25, 2024. *https://www.epa.gov/uic/table-epas-draft-and-final-class-vi-well-permits* Last updated January 19, 2024.

[475] U.S. EPA Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[476] U.S. EPA. Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[477] Wyoming DEQ. Water Quality. Wyoming grants its first three Class VI permits. By Kimberly Mazza, December 14, 2023 *https://deq.wyoming.gov/2023/12/wyoming-grants-its-first-three-class-vi-permits/.*

[478] Wyoming DEQ Class VI Permit Applications. Trailblazer permit application. *https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi.*

[479] North Dakota Oil and Gas Division, Class VI—Geologic Sequestration Wells. *https://www.dmr.nd.gov/dmr/oilgas/ClassVI.*

[480] EPA Approves Permits to Begin Construction of Wabash Carbon Services Underground Injection Wells in Indiana's Vermillion and Vigo Counties. (2024) *https://www.epa.gov/uic/epa-approves-permits-wabash-carbon-services-underground-injection-wells-indianas-vigo-and*

[481] U.S. EPA Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[482] U.S. EPA Class VI Permit Application. "Intent to Issue Four (4) Class VI Geologic Carbon Sequestration Underground Injection Control (UIC)

an existing UIC Class II well that would be converted to a UIC Class VI well for the TerraVault project.[484]

Geologic sequestration has been proven to be successful and safe in projects internationally. In Norway, facilities conduct offshore sequestration under the Norwegian continental shelf.[485] In addition, the Sleipner CO_2 Storage facility in the North Sea, which began operations in 1996, injects around 1 million metric tons of CO_2 per year from natural gas processing.[486] The Snohvit CO_2 Storage facility in the Barents Sea, which began operations in 2008, injects around 0.7 million metric tons of CO_2 per year from natural gas processing. The SaskPower carbon capture and sequestration facility at Boundary Dam Power Station in Saskatchewan, Canada had, as of the end of 2023, captured 5.6 million metric tons of CO_2 since it began operating in 2014.[487] Other international sequestration facilities in operation include Glacier Gas Plant MCCS (Canada),[488] Quest (Canada), and Qatar LNG CCS (Qatar). The CarbFix project in Iceland injects CO_2 into a geologic formation in which the CO_2 reacts with basalt rock formations to form stone. The CarbFix project has injected approximately 100,000 metric tons of CO_2 into geologic formations since 2014.[489]

EOR, the process of injecting CO_2 into oil and gas formations to extract additional oil and gas, has been successfully used for decades at numerous production fields throughout the United States to increase oil and gas recovery. The oil and gas industry in the United States has nearly 60 years of experience with EOR.[490] This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure geologic sequestration that can be used for deployment of CCS across geographically diverse areas. The amount of CO_2 that can be injected for an EOR project and the duration of operations are of similar magnitude to the duration and volume of CO_2 that is expected to be captured from fossil fuel-fired EGUs. The Farnsworth Unit, the Camrick Unit, the Shute Creek Facility, and the Core Energy CO_2-EOR facility are all examples of operations that store anthropogenic CO_2 as a part of EOR operations.[491] [492] Currently, 13 states have active EOR operations, and these states also have areas that are amenable to deep saline sequestration in either onshore or offshore locations.[493]

(3) EPAct05-Assisted Geologic Sequestration Projects

Consistent with the EPA's legal interpretation that the Agency can rely on experience from EPAct05 funded facilities in conjunction with other information, this section provides examples of EPAct05-assisted geologic sequestration projects. While the EPA has determined that the sequestration component of CCS is adequately demonstrated based on the non-EPAct05 examples discussed above, adequate demonstration of geologic sequestration is further corroborated by planned and operational geologic sequestration projects assisted by grants, loan guarantees, and the IRC section 48A federal tax credit for "clean coal technology" authorized by the EPAct05.[494]

At present, there are 13 operational and one post-injection phase commercial carbon sequestration facilities in the United States.[495] [496] Red Trail Energy CCS Project in North Dakota and Illinois Industrial Carbon Capture and Storage in Illinois are dedicated saline sequestration facilities, while the other facilities, including Petra Nova in Texas, are sequestration via EOR.[497] [498] Several other facilities are under development.[499] The Red Trail Energy CCS facility in North Dakota began injecting CO_2 captured from ethanol production plants in 2022.[500] This project is expected to inject 180,000 tons of CO_2 per year.[501] The Illinois Industrial Carbon Capture and Storage Project began injecting CO_2 from ethanol production into the Mount Simon Sandstone in April 2017. According to the facility's report to the EPA's Greenhouse Gas Reporting Program (GHGRP), as of 2022, 2.9 million metric tons of CO_2 had been injected into the saline reservoir.[502] CO_2 injection for one of the two permitted Class VI wells ceased in 2021 and this well is now in the post-operation data collection phase.[503]

There are additional planned geologic sequestration projects under review by the EPA and across the United States.[504] [505] Project Tundra, a saline sequestration project planned at the lignite-fired Milton R. Young Station in North Dakota is projected to capture 4 million metric tons of CO_2 annually.[506] In Wyoming, Class VI permit

Permits for Carbon TerraVault JV Storage Company Sub 1, LLC. EPA–R09–OW–2023–0623." *https://www.epa.gov/publicnotices/intent-issue-class-vi-underground-injection-control-permits-carbon-terravault-jv.*

483 California Resources Corporation. "Carbon TerraVault Potential Storage Capacity."*https://www.crc.com/carbon-terravault/Vaults/default.aspx.*

484 U.S. EPA Class VI Permit Application. "Intent to Issue Four (4) Class VI Geologic Carbon Sequestration Underground Injection Control (UIC) Permits for Carbon TerraVault JV Storage Company Sub 1, LLC. EPA–R09–OW–2023–0623.

485 Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage. *https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/.*

486 Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

487 BD3 Status Update: Q3 2023. *https://www.saskpower.com/about-us/our-company/blog/2023/bd3-status-update-q3-2023.*

488 Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

489 CarbFix Operations. (2024). *https://www.carbfix.com/.*

490 NETL. (2010). Carbon Dioxide Enhanced Oil Recovery. *https://www.netl.doe.gov/sites/default/files/netl-file/co2_eor_primer.pdf.*

491 Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

492 Greenhouse Gas Reporting Program monitoring reports for these facilities are available at *https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide#decisions.*

493 U.S. DOE NETL, Carbon Storage Atlas, Fifth Edition, September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.*

494 80 FR 64541–42 (October 23, 2015).

495 Clean Air Task Force. (August 3, 2023). U.S. Carbon Capture Activity and Project Map. *https://www.catf.us/ccsmapus/.*

496 Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

497 Reuters. (September 14, 2023) "Carbon capture project back at Texas coal plant after 3-year shutdown". *https://www.reuters.com/business/energy/carbon-capture-project-back-texas-coal-plant-after-3-year-shutdown-2023-09-14/.*

498 Clean Air Task Force. (August 3, 2023). U.S. Carbon Capture Activity and Project Map. *https://www.catf.us/ccsmapus/.*

499 Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

500 Ibid.

501 Ibid.

502 EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.

503 University of Illinois Urbana-Champaign, Prairie Research Institute. (2022). Data from landmark Illinois Basin carbon storage project are now available. *https://blogs.illinois.edu/view/7447/54118905.*

504 In addition, Denbury Resources injected CO_2 into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year as part of a DOE Southeast Regional Carbon Sequestration Partnership study. The Texas Bureau of Economic Geology tested a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi. Texas Bureau of Economic Geology, "Cranfield Log." *https://www.beg.utexas.edu/gccc/research/cranfield.*

505 EPA Class VI Permit Tracker. *https://www.epa.gov/system/files/documents/2024-02/class-vi-permit-tracker_2-5-24.pdf.* Accessed February 5, 2024.

506 Project Tundra. "Project Tundra." *https://www.projecttundrand.com/.*

applications have been issued by the Wyoming Department of Environmental Quality for the proposed Eastern Wyoming Sequestration Hub project, a saline sequestration facility proposed to be located in Southwestern Wyoming.[507] At full capacity, the facility would permanently store up to 5 million metric tons of CO_2 captured from industrial facilities annually in the Nugget saline sandstone reservoir.[508] In Texas, three NGCCs plan to add carbon capture equipment. Deer Park NGCC plans to capture 5 million tons per year, Quail Run NGCC plans to capture 1.5 million tons of CO_2 per year, and Baytown NGCC plans to capture up to 2 million tons of CO_2 per year.[509] [510]

(4) Security of Geologic Sequestration and Related Regulatory Requirements

As discussed in section VII.C.1.a.i(D)(2) of this preamble, there have been numerous instances of geologic sequestration in the U.S. and overseas, and the U.S. has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. This regulatory framework includes the UIC well regulations pursuant to SDWA authority, and the GHGRP pursuant to CAA authority.

Regulatory oversight of geologic sequestration is built upon an understanding of the proven mechanisms by which CO_2 is retained in geologic formations. These mechanisms include (1) Structural and stratigraphic trapping (generally trapping below a low permeability confining layer); (2) residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the geologic formation); (3) solubility trapping (dissolution in the in situ formation fluids); (4) mineral trapping (reaction with the minerals in the geologic formation and confining layer to produce carbonate minerals); and (5) preferential adsorption trapping (adsorption onto organic matter in coal and shale).

(a) Overview of Legal and Regulatory Framework

For the reasons detailed below, the UIC Program, the GHGRP, and other regulatory requirements comprise a detailed regulatory framework for geologic sequestration in the United States. This framework is analyzed in a 2021 report from the Council on Environmental Quality (CEQ),[511] and statutory and regulatory frameworks that may be applicable for CCS are summarized in the EPA CCS Regulations Table.[512] [513] This regulatory framework includes the UIC regulations, promulgated by the EPA under the authority of the Safe Drinking Water Act (SDWA); and the GHGRP, promulgated by the EPA under the authority of the CAA. The requirements of the UIC and GHGRP programs work together to ensure that sequestered CO_2 will remain securely stored underground. Furthermore, geologic sequestration efforts on Federal lands as well as those efforts that are directly supported with Federal funds would need to comply with the NEPA and other Federal laws and regulations, depending on the nature of the project.[514] In cases where sequestration is conducted offshore, the SDWA, the Marine Protection, Research, and Sanctuaries Act (MPRSA) or the Outer Continental Shelf Lands Act (OCSLA) may apply. The Department of Interior Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management are developing new regulations and creating a program for oversight of carbon sequestration activities on the outer continental shelf.[515] Furthermore, Title V of the Federal Land Policy and Management Act of 1976 (FLPMA) and its implementing regulations, 43 CFR part 2800, authorize the Bureau of Land Management (BLM) to issue rights-of-way (ROWs) to geologically sequester CO_2 in Federal pore space, including BLM ROWs for the necessary physical infrastructure and for the use and occupancy of the pore space itself. The BLM has published a policy defining access to pore space on BLM lands, including clarification of Federal policy for situations where the surface and pore space are under the control of different Federal agencies.[516]

(b) Underground Injection Control (UIC) Program

The UIC regulations, including the Class VI program, authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water (USDW). These regulations are built upon nearly a half-century of Federal experience regulating underground injection wells, and many additional years of state UIC program expertise. The IIJA established a $50 million grant program to assist states and tribal regulatory authorities in developing and implementing UIC Class VI programs.[517] Major components included in UIC Class VI permits are site characterization, area of review,[518] corrective action,[519] well construction and operation, testing and monitoring, financial responsibility, post-injection site care, well plugging, emergency and remedial response, and site closure. The EPA's UIC regulations are included in 40 CFR parts 144–147. The UIC regulations ensure that injected CO_2 does not migrate out of the authorized injection zone, which in turn ensures that CO_2 is securely stored underground.

Review of a UIC permit application by the permitting authority, including for Class VI geologic sequestration, entails a multidisciplinary evaluation to determine whether the application includes the required information, is technically accurate, and supports a determination that USDWs will not be endangered by the proposed injection

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[507] Wyoming DEQ Class VI Permit Applications. *https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/.*

[508] *Id.*

[509] Calpine. (2023). Calpine Carbon Capture, Bayton, Texas. *https://calpinecarboncapture.com/wp-content/uploads/2023/04/Calpine-Baytown-One-Pager-English-1.pdf.*

[510] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[511] CEQ. (2021). "Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration." *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[512] EPA. 2023. Regulatory and Statutory Authorities Relevant to Carbon Capture and Sequestration (CCS) Projects. *https://www.epa.gov/system/files/documents/2023-10/regulatory-and-statutory-authorities-relevant-to-carbon-capture-and-sequestration-ccs-projects.pdf.*

[513] This table serves as a reference of many possible authorities that may affect a CCS project (including site selection, capture, transportation, and sequestration). Many of the authorities listed in this table would apply only in specific circumstances.

[514] CEQ. "Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration." 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[515] Department of the Interior. (2023). BSEE Budget. *https://www.doi.gov/ocl/bsee-budget.*

[516] National Policy for the Right-of-Way Authorizations Necessary for Site Characterization, Capture, Transportation, Injection, and Permanent Geologic Sequestration of Carbon Dioxide in Connection with Carbon Sequestration Projects. BLM IM 2022–041 Instruction Memorandum, June 8, 2022. *https://www.blm.gov/policy/im-2022-041.*

[517] EPA. Underground Injection Control Class VI Wells Memorandum. (December 9, 2022). *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[518] Per 40 CFR 146.84(a), the area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

[519] UIC permitting authorities may require corrective action for existing wells within the area of review to ensure protection of underground sources of drinking water.

activity.[520] The EPA promulgated UIC regulations to ensure underground injection wells are constructed, operated, and closed in a manner that is protective of USDWs and to address potential risks to USDWs associated with injection activities.[521] The UIC regulations address the major pathways by which injected fluids can migrate into USDWs, including along the injection well bore, via improperly completed or plugged wells in the area near the injection well, direct injection into a USDW, faults or fractures in the confining strata, or lateral displacement into hydraulically connected USDWs. States may apply to the EPA to be the UIC permitting authority in the state and receive primary enforcement authority (primacy). Where a state has not obtained primacy, the EPA is the UIC permitting authority.

Recognizing that CO_2 injection, for the purpose of geologic sequestration, poses unique risks relative to other injection activities, the EPA promulgated Federal Requirements Under the UIC Program for Carbon Dioxide GS Wells, known as the Class VI Rule, in December 2010.[522] The Class VI Rule created and set requirements for a new class of injection wells, Class VI. The Class VI Rule builds upon the long-standing protective framework of the UIC Program, with requirements that are tailored to address issues unique to large-scale geologic sequestration, including large injection volumes, higher reservoir pressures relative to other injection formations, the relative buoyancy of CO_2, the potential presence of impurities in captured CO_2, the corrosivity of CO_2 in the presence of water, and the mobility of CO_2 within subsurface geologic formations. These additional protective requirements include more extensive geologic testing, detailed computational modeling of the project area and periodic re-evaluations, detailed requirements for monitoring and tracking the CO_2 plume and pressure in the injection zone, unique financial responsibility requirements, and extended post-injection monitoring and site care.

UIC Class VI permits are designed to ensure that geologic sequestration does not cause the movement of injected CO_2 or formation fluids outside the authorized injection zone; if monitoring indicates leakage of injected CO_2 from the injection zone, the leakage may trigger a response per the permittee's Class VI Emergency and Remedial Response Plan including halting injection, and the permitting authority may prescribe additional permit requirements necessary to prevent such movement to ensure USDWs are protected or take appropriate enforcement action if the permit has been violated.[523] Class II EOR permits are also designed to ensure the protection of USDWs with requirements appropriate for the risks of the enhanced recovery operation. In general, the EPA believes that the protection of USDWs by preventing leakage of injected CO_2 out of the injection zone will also ensure that CO_2 is sufficiently sequestered in the subsurface, and therefore will not leak from the subsurface to the atmosphere.

The UIC program works with injection well operators throughout the life of the well to confirm practices do not pose a risk to USDWs. The program conducts inspections to verify compliance with the UIC permit, including checking for leaks.[524] Inspections are only one way that programs deter noncompliance. Programs also evaluate periodic monitoring reports submitted by operators and discuss potential issues with operators. If a well is found to be out of compliance with applicable requirements in its permit or UIC regulations, the program will identify specific actions that an operator must take to address the issues. The UIC program may assist the operator in returning the well to compliance or use administrative or judicial enforcement to return a well to compliance.

UIC program requirements address potential safety concerns with induced seismicity. More specifically, through the UIC Class VI program, the EPA has put in place mechanisms to identify, monitor, and reduce risks associated with induced seismicity in any areas within or surrounding a sequestration site through permit and program requirements such as site characterization and monitoring, and the requirement for applicants to demonstrate that induced seismic activity will not endanger USDWs.[525] The National Academy of Sciences released a report in 2012 on induced seismicity from CCS and determined that with appropriate site selection, a monitoring program, a regulatory system, and the appropriate use of remediation methods, the induced seismicity risks of geologic sequestration could be mitigated.[526] Furthermore, the Ground Water Protection Council and Interstate Oil and Gas Compact Commission have published a ''Potential Induced Seismicity Guide.'' This report found that the strategies for avoiding, mitigating, and responding to potential risks of induced seismicity should be determined based on site-specific characteristics (*i.e.*, local geology). These strategies could include supplemental seismic monitoring, altering operational parameters (such as rates and pressures) to reduce the ground motion hazard and risk, permit modification, partial plug back of the well, controlled restart (if feasible), suspending or revoking injection authorization, or stopping injection and shutting in a well.[527] The EPA's UIC National Technical Workgroup released technical recommendations in 2015 to address induced seismicity concerns in Class II wells and elements of these recommendations have been utilized in developing Class VI emergency and remedial response plans for Class VI permits.[528] [529] For example, as identified

[520] EPA. EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

[521] See 40 CFR parts 124, 144–147.

[522] EPA. (2010). Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells; Final Rule, 75 FR 77230, December 10, 2010 (codified at 40 CFR part 146, subpart H).

[523] See 40 CFR 144.12(b) (prohibition of movement of fluid into USDWs); 40 CFR 146.86(a)(1) (Class VI injection well construction requirements); 40 CFR 146(a) (Class VI injection well operation requirements); 40 CFR 146.94 (emergency and remedial response).

[524] EPA. (2020). Underground Injection Control Program. *https://www.epa.gov/sites/default/files/2020-04/documents/uic_fact_sheet.pdf.*

[525] *See* 40 CFR 146.82(a)(3)(v) (requiring the permit applicant to submit and the permitting authority to consider information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment); EPA. (2018). Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. U.S. Environmental Protection Agency Office of Water (4606M) EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[526] National Research Council. (2013). Induced Seismicity Potential in Energy Technologies. Washington, DC: The National Academies Press. *https://doi.org/10.17226/13355.*

[527] Ground Water Protection Council and Interstate Oil and Gas Compact Commission. (2021). Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection. *https://www.gwpc.org/wp-content/uploads/2022/12/FINAL_Induced_Seismicity_2021_Guide_33021.pdf.*

[528] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[529] EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/*

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by the EPA's UIC National Technical Workgroup, sufficient pressure buildup from disposal activities, the presence of Faults of Concern (*i.e.*, a fault optimally oriented for movement and located in a critically stressed region), and the existence of a pathway for allowing the increased pressure to communicate with the fault contribute to the risk of injection-induced seismicity. The UIC requirements, including site characterization (*e.g.*, ensuring the confining zone [530] is free of faults of concern) and operating requirements (*e.g.*, ensuring injection pressure in the injection zone is below the fracture pressure), work together to address these components and reduce the risk of injection-induced seismicity, particularly any injection-induced seismicity that could be felt by people at the surface.[531] Additionally, the EPA recommends that Class VI permits include an approach for monitoring for seismicity near the site, including seismicity that cannot be felt at the surface, and that injection activities be stopped or reduced in certain situations if seismic activity is detected to ensure that no seismic activity will endanger USDWs.[532] This also reduces the likelihood of any future injection-induced seismic activity that will be felt at the surface.

Furthermore, during site characterization, if any of the geologic or seismic data obtained indicate a substantial likelihood of seismic activity, the EPA may require further analyses, potential planned operational changes, and additional monitoring.[533] The EPA has the authority to require seismic monitoring as a condition of the UIC permit if appropriate, or to deny the permit if the injection-induced seismicity risk could endanger USDWs.

The EPA believes that meaningful engagement with local communities is an important step in the development of geologic sequestration projects and has programs and public participation requirements in place to support this process. The EPA is committed to advancing EJ for overburdened communities in all its programs, including the UIC Class VI program.[534] The EPA is also committed to supporting states' and tribes' efforts to obtain UIC Class VI primacy and strongly encourages such states and tribes to incorporate environmental justice principles and equity into proposed UIC Class VI programs.[535] The EPA is taking steps to address EJ in accordance with Presidential Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All* (88 FR 25251, April 26, 2023). In 2023, the EPA released *Environmental Justice Guidance for UIC Class VI Permitting and Primacy* that builds on the 2011 *UIC Quick Reference Guide: Additional Tools for UIC Program Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process.*[536] [537] The 2023 guidance serves as an operating framework for identifying, analyzing, and addressing EJ concerns in the context of implementing and overseeing UIC permitting and primacy programs, including primacy approvals. The EPA notes that while this guidance is focused on the UIC Class VI program, EPA Regions should apply them to the other five injection well classes wherever possible, including class II. The guidance includes recommended actions across five themes to address various aspects of EJ in UIC Class VI permitting including: (1) identify communities with potential EJ concerns, (2) enhance public involvement, (3) conduct appropriately scoped EJ assessments, (4) enhance transparency throughout the permitting process, and (5) minimize adverse effects to USDWs and the communities they may serve.[538]

As a part of the UIC Class VI permit application process, applicants and the EPA Regions should complete an EJ review using the EPA's EJScreen Tool, an online mapping tool that integrates numerous demographic, socioeconomic, and environmental data sets that are overlain on an applicant's UIC Area of Review to identify whether any disadvantaged communities are encompassed.[539] If the results indicate a potential EJ impact, applicants and the EPA Regions should consider potential measures to mitigate the impacts of the UIC Class VI project on identified vulnerable communities and enhance the public participation process to be inclusive of all potentially affected communities (*e.g.*, conduct early targeted outreach to communities and identify and mitigate any communication obstacles such as language barriers or lack of technology resources).[540]

ER technologies are used in oil and gas reservoirs to increase production. Injection wells used for ER are regulated through the UIC Class II program. Injection of CO_2 is one of several techniques used in ER. Sometimes ER uses CO_2 from anthropogenic sources such as natural gas processing, ammonia and fertilizer production, and coal gasification facilities. Through the ER process, much of the injected CO_2 is recovered from production wells and can be separated and reinjected into the subsurface formation, resulting in the storage of CO_2 underground. The EPA's Class II regulations were designed to regulate ER injection wells, among other injection wells associated with oil and natural gas production. See *e.g.*, 40 CFR 144.6(b)(2). The EPA's Class II program is designed to prevent Class II injection activities from endangering USDWs. The Class II programs of states and tribes must be approved by the EPA and must meet the EPA regulatory requirements for Class II programs, 42 U.S.C. 300h–1, or otherwise represent an effective program to prevent endangerment of USDWs. 42 U.S.C 300h–4.

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documents/implementation_manual_508_010318.pdf.

[530] "Confining zone" means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone. 40 CFR 146.3.

[531] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[532] See EPA. Emergency and Remedial Response Plan: 40 CFR 146.94(a) template. *https://www.epa.gov/system/files/documents/2022-03/err_plan_template.docx.* See also EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[533] 40 CFR 146.82(a)(3)(v).

[534] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf; see also* EPA. Letter from the EPA Administrator Michael S. Regan to U.S. State Governors. December 9, 2022. *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[535] EPA. (2023). Targeted UIC program grants for Class VI Wells. *https://www.epa.gov/uic/underground-injection-control-grants#ClassVI_Grants.*

[536] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[537] EPA. (2011). Geologic Sequestration of Carbon Dioxide—UIC Quick Reference Guide. *https://www.epa.gov/sites/default/files/2015-07/documents/epa816r11002.pdf.*

[538] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[539] EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

[540] EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

In promulgating the Class VI regulations, the EPA recognized that if the business model for ER shifts to focus on maximizing CO_2 injection volumes and permanent storage, then the risk of endangerment to USDWs is likely to increase. As an ER project shifts away from oil and/or gas production, injection zone pressure and carbon dioxide volumes will likely increase if carbon dioxide injection rates increase, and the dissipation of reservoir pressure will decrease if fluid production from the reservoir decreases. Therefore, the EPA's regulations require the operator of a Class II well to obtain a Class VI permit when there is an increased risk to USDWs. 40 CFR 144.19.[541] While the EPA's regulations require the Class II well operator to assess whether there is an increased risk to USDWs (considering factors identified in the EPA's regulations), the permitting authority can also make this assessment and, in the event that an operator makes changes to Class II operations such that the increased risk to USDWs warrants transition to Class VI and the operator does not notify the permitting authority, the operator may be subject to SDWA enforcement and compliance actions to protect USDWs, including cessation of injection. The determination of whether there is an increased risk to USDWs would be based on factors specified in 40 CFR 144.19(b), including increase in reservoir pressure within the injection zone; increase in CO_2 injection rates; and suitability of the Class II Area of Review (AoR) delineation.

(c) Greenhouse Gas Reporting Program (GHGRP)

The GHGRP requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the United States. Approximately 8,000 facilities are required to report their emissions, injection, and/or supply activity annually, and the non-confidential reported data are made available to the public around October of each year. To complement the UIC regulations, the EPA included in the GHGRP air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration. These requirements are included in 40 CFR part 98, subpart RR and subpart VV, also referred to as "GHGRP subpart RR" and "GHGRP subpart VV."

GHGRP subpart RR applies to "any well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations" [542] and provides the monitoring and reporting mechanisms to quantify CO_2 storage and to identify, quantify, and address potential leakage. The EPA designed GHGRP subpart RR to complement the UIC monitoring and testing requirements. See *e.g.*, 40 CFR 146.90–91. Reporting under GHGRP subpart RR is required for, but not limited to, all facilities that have received a UIC Class VI permit for injection of CO_2.[543] Under existing GHGRP regulations, facilities that conduct ER in Class II wells are not subject to reporting data under GHGRP subpart RR unless they have chosen to submit a proposed monitoring, reporting, and verification (MRV) plan to the EPA and received an approved plan from the EPA. Facilities conducting ER and who do not choose to submit a subpart RR MRV plan to the EPA would otherwise be required to report CO_2 data under subpart UU.[544] GHGRP subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the mass of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO_2 sequestered using a mass balance approach; and report annual monitoring activities.[545] [546] [547] [548] Extensive subsurface monitoring is required for UIC Class VI wells at 40 CFR 146.90 and is the primary means of determining if the injected CO_2 remains in the authorized injection zone and otherwise does not endanger any USDW, and monitoring under a GHGRP subpart RR MRV Plan complements these requirements. The MRV plan includes five major components: a delineation of monitoring areas based on the CO_2 plume location; an identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways; a strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs; an approach for establishing the expected baselines for monitoring CO_2 surface leakage; and, a summary of considerations made to calculate site-specific variables for the mass balance equation.[549]

In April 2024, the EPA finalized a new GHGRP subpart, "Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery (EOR) Using ISO 27916" (or GHGRP subpart VV).[550] GHGRP subpart VV applies to facilities that quantify the geologic sequestration of CO_2 in association with EOR operations in conformance with the ISO standard designated as CSA/ANSI ISO 27916:2019, Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery. Facilities that have chosen to submit an MRV plan and report under GHGRP subpart RR must not report data under GHGRP subpart VV. GHGRP subpart VV is largely modeled after the requirements in this ISO standard and focuses on quantifying storage of CO_2. Facilities subject to GHGRP subpart VV must include in their GHGRP annual report a copy of their EOR Operations Management Plan (EOR OMP). The EOR OMP includes a description of the EOR complex and engineered system, establishes that the EOR complex is adequate to provide safe, long-term containment of CO_2, and includes site-specific and other information including a geologic characterization of the EOR complex, a description of the facilities within the EOR project, a description of all wells and other engineered features in the EOR project, and the operations history of the project reservoir.[551]

Based on the understanding developed from existing projects, the security of sequestered CO_2 is expected to increase over time after injection ceases.[552] This is due to trapping mechanisms that reduce CO_2 mobility over time (*e.g.*, physical CO_2 trapping by a low-permeability geologic seal or chemical trapping by conversion or adsorption).[553] The EPA acknowledges the potential for some leakage of CO_2 to the atmosphere at sequestration sites, primarily while injection operations are active. For example, small quantities of the CO_2 that were sent to the

[541] EPA. (2015). Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI. *https://www.epa.gov/sites/default/files/2015-07/documents/class2eorclass6memo_1.pdf.*

[542] See 40 CFR 98.440.

[543] 40 CFR 98.440.

[544] As discussed in section X.C.5.b, entities conducting CCS to comply with this rule would be required to send the captured CO_2 to a facility that reports data under subpart RR or subpart VV.

[545] 40 CFR 98.446.

[546] 40 CFR 98.448.

[547] 40 CFR 98.446(f)(9) and (10).

[548] 40 CFR 98.446(f)(12).

[549] 40 CFR 98.448(a).

[550] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[551] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[552] "Report of the Interagency Task Force on Carbon Capture and Storage." 2010. *https://www.osti.gov/servlets/purl/985209.*

[553] See, *e.g.*, Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

sequestration site may be emitted from leaks in pipes and valves that are traversed before the CO_2 actually reaches the sequestration formation. However, the EPA's robust UIC regulatory protections protect against leakage out of the injection zone. Relative to the 46.75 million metric tons of CO_2 reported as sequestered under subpart RR of the GHGRP between 2016 to 2022, only 196,060 metric tons were reported as leakage/emissions to the atmosphere in the same time period (representing less than 0.5% of the sequestration amount). Of these emissions, most were from equipment leaks and vented emissions of CO_2 from equipment located on the surface rather than leakage from the subsurface.[554] Furthermore, any leakage of CO_2 at a sequestration facility would be required to be quantified and reported under the GHGRP subpart RR or subpart VV, and such data are made publicly available on the EPA's website.

(5) Timing of Permitting for Sequestration Sites

As previously discussed, the EPA is the Class VI permitting authority for states, tribes, and territories that have not obtained primacy over their Class VI programs.[555] The EPA is committed to reviewing UIC Class VI permits as expeditiously as possible when the agency is the permitting authority. The EPA has the experience to properly regulate and review permits for UIC Class VI injection wells, and technical experts of multiple disciplines to review permit applications submitted to the EPA.

The EPA has seen a considerable uptick in Class VI permit applications over the past few years. The 2018 passage of revisions and enhancements to the IRC section 45Q tax credit that provides tax credits for carbon oxide (including CO_2) sequestration has led to an increase in Class VI permit applications submitted to the EPA. The 2022 IRA further expanded the IRC section 45Q tax credit and the 2021 IIJA established a $50 million program for grants to help states and tribes in developing and implementing a UIC Class VI primacy program, leading to even more interest in this area.[556] Between 2011, when the Class VI rule went into effect, and 2020, the EPA received a total of 8 permit applications for Class VI wells. The EPA then received 12 Class VI permit applications in 2021, 44 in 2022, and 123 in 2023. As of March 2024, the EPA has 130 Class VI permit applications under review (56 permit applications were transferred to Louisiana in February 2024 when the EPA rule granting Class VI primacy to the state became effective). The majority of those 130 permit applications (63%) were submitted to the EPA within the past 12 months. Also, as of March 2024, the EPA has issued eight Class VI permits, including six for projects in Illinois and two for projects in Indiana, and has released for public comment four additional draft permits for proposed projects in California. Two of the permits are in the pre-operation phase, one is in the injection phase, and one is in the post-injection monitoring phase.

In light of the recent flurry of interest in this area, the EPA is devoting increased resources to the Class VI program, including through increased staffing levels in order to meet the increased demand for action on Class VI permit applications.[557] Reviewing a Class VI permit application entails a multidisciplinary evaluation to determine whether the application includes the required information, is technically accurate, and supports a risk-based determination that underground sources of drinking water will not be endangered by the proposed injection activity. A wide variety of technical experts—from geologists to engineers to physical scientists—review permit applications submitted to the EPA. The EPA has been working to develop staff expertise and increase capacity in the UIC program, and the agency has effectively deployed appropriated resources over the last five years to scale UIC program staff from a few employees to the equivalent of more than 25 full-time employees across the agency's headquarters and regional offices. We expect that the additional resources and staff capacity for the Class VI program will lead to increased efficiencies in the Class VI permitting process.

In addition to increased staffing resources, the EPA has made considerable improvements to the Class VI permitting process to reduce the time needed to make final permitting decisions for Class VI wells while maintaining a robust and thorough review process that ensures USDWs are protected. The EPA has created additional resources for applicants including upgrading the Geologic Sequestration Data Tool (GSDT) to guide applicants through the application process.[558] The EPA has also created resources for permit writers including training series and guidance documents to build capacity for Class VI permitting.[559] Additionally, the EPA issued internal guidelines to streamline and create uniformity and consistency in the Class VI permitting process, which should help to reduce permitting timeframes. These internal guidelines include the expectation that EPA Regions will classify all Class VI well applications received on or after December 12, 2023, as applications for major new UIC injection wells, which requires the Regions to develop project decision schedules for reviewing Class VI permit applications. The guidelines also set target timeframes for components of the permitting process, such as the number of days EPA Regions should set for public comment periods and for developing responses to comments and final permit decisions. The EPA will continue to evaluate its internal UIC permitting processes to identify potential opportunities for streamlining and other improvements over time. Although the available data for Class VI wells is limited, the timeframe for processing Class I wells, which follows a similar regulatory structure, is typically less than 2 years.[560]

The EPA notes that a Class VI permit tracker is available on its website.[561] This tracker shows information for the 44 projects (representing 130 wells) that have submitted Class VI applications to the EPA, including details such as the current permit review stage, whether a project has been sent a Notice of Deficiency (NOD) or Request for Additional Information (RAI), and the applicant's response time to any NODs or RAIs. As mentioned above, most of the permits submitted to the EPA have been submitted within the past 12

554 Based on subpart RR data retrieved from the EPA Facility Level Information on Greenhouse Gases Tool (FLIGHT), at *https://ghgdata.epa.gov/ghgp/main.do*. Retrieved March 2024.

555 See 40 CFR part 145 (State UIC Program Requirements), 40 CFR part 147 (State, Tribal, and EPA-Administered Underground Injection Control Programs).

556 EPA. (2023). Targeted UIC program grants for Class VI Wells *https://www.epa.gov/uic/underground-injection-control-grants#ClassVI_Grants*.

557 EPA. (2023). Testimony Of Mr. Bruno Pigott, Principal Deputy Assistant Administrator for Water, U.S. Environmental Protection Agency, Hearing On Carbon Capture And Storage. *https://www.epa.gov/system/files/documents/2023-11/testimony-pigott-senr-hearing-nov-2-2023_-cleared.pdf*.

558 EPA. (2023). Geologic Sequestration Data Tool (GSDT). *https://www.epa.gov/system/files/documents/2023-10/geologic-sequestration-data-tool_factsheet_oct2023.pdf*.

559 EPA. (2023). Final Class VI Guidance Documents. *https://www.epa.gov/uic/final-class-vi-guidance-documents*.

560 EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf*.

561 EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa*.

months. The EPA aims to review complete Class VI applications and issue permits when appropriate within approximately 24 months. This timeframe is dependent on several factors, including the complexity of the project and the quality and completeness of the submitted application. It is important for the applicant to submit a complete application and provide any information requested by the permitting agency in a timely manner so as not to extend the overall time for the review.

States may apply to the EPA for primacy to administer the Class VI programs within their states. The primacy application process has four phases: (1) pre-application activities, (2) completeness review and determination, (3) application evaluation, and (4) rulemaking and codification. To date, three states have been granted primacy for Class VI wells, including North Dakota, Wyoming, and most recently Louisiana.[562] As discussed above, North Dakota has issued 6 Class VI permits since receiving Class VI primacy in 2018, and Wyoming issued its first three Class VI permits in December 2023.[563 564 565] The EPA finalized a rule granting Louisiana Class VI primacy in January 2024 and the state's program became effective in February 2024. At that time, EPA Region 6 transferred 56 Class VI permit applications for projects in Louisiana to the state for continued review and permit issuance if appropriate. Prior to receiving primacy, the state worked with the EPA in understanding where each application was in the evaluation process. Currently, the EPA is working with the states of Texas, Arizona, and West Virginia as they are developing their UIC primacy applications.[566] Arizona submitted a primacy application to the EPA on February 13, 2024.[567] Texas and West Virginia are engaging with the EPA to complete pre-application activities.[568] If more states apply for and receive Class VI primacy, the number of permits in EPA review is expected to be reduced. The EPA has also created resources for regulators including training series and guidance documents to build capacity for Class VI permitting within UIC programs across the U.S. Through state primacy for Class VI programs, state expertise and capacity can be leveraged to support effective and efficient permit application reviews. The IIJA established a $50 million grant program to support states, Tribes, and territories in developing and implementing UIC Class VI programs. The EPA has allocated $1,930,000 to each state, tribe, and territory that submitted letters of intent.[569]

(6) Comments Received on Geologic Sequestration and Responses

The EPA received comments on geologic sequestration. Those comments, and the EPA's responses, are as follows.

Comment: Some commenters expressed concerns that the EPA has not demonstrated the adequacy of carbon sequestration at a commercial scale.

Response: The EPA disagrees that commercial carbon sequestration capacity will be inadequate to support this rule. As detailed in section VII.C.1.a.i(D)(1), commercial geologic sequestration capacity is growing in the United States. Multiple commercial sequestration facilities, other than those funded under EPAct05, are in construction or advanced development, with some scheduled to open for operation as early as 2025.[570] These facilities have proposed sequestration capacities ranging from 0.03 to 6 million tons of CO_2 per year. The EPA and states with approved UIC Class VI programs (including Wyoming, North Dakota, and Louisiana) are currently reviewing UIC Class VI geologic sequestration well permit applications for proposed sequestration sites in fourteen states.[571 572 573] As of March 2024, there are 44 projects with 130 injection wells are under review by the EPA.[574] Furthermore, the EPA anticipates that as the demand for commercial sequestration grows, more commercial sites will be developed in response to financial incentives.

Comment: Some commenters expressed concern about leakage of CO_2 from sequestration sites.

Response: The EPA acknowledges the potential for some leakage of CO_2 to the atmosphere at sequestration sites (such as leaks through valves before the CO_2 reaches the injection formation). However, as detailed in the preceding sections of preamble, the EPA's robust UIC permitting process is adequate to protect against CO_2 escaping the authorized injection zone (and then entering the atmosphere). As discussed in the preceding section, leakage out of the injection zone could trigger emergency and remedial response action including ceasing injection, possible permit modification, and possible enforcement action. Furthermore, the GHGRP subpart RR and subpart VV regulations prescribe accounting methodologies for facilities to quantify and report any potential leakage at the surface, and the EPA makes sequestration data and related monitoring plans publicly available on its website. The reported emissions/leakage from sequestration sites under subpart RR is a comparatively small fraction (less than 0.5 percent) of the associated sequestration volumes, with most of these reported emissions attributable to leaks or vents from surface equipment.

Comment: Some commenters expressed concern over safety due to induced seismicity.

Response: The EPA believes that the UIC program requirements adequately address potential safety concerns with induced seismicity at site-adjacent communities. More specifically, through the UIC Class VI program the EPA has put in place mechanisms to identify,

[562] On December 28, 2023, the EPA Administrator signed a final rule granting Louisiana's request for primacy for UIC Class VI junction wells located within the state. See EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[563] Wyoming Department of Environmental Quality. (2023). Wyoming grants its first three Class VI permits. *https://deq.wyoming.gov/2023/12/wyoming-grants-its-first-three-class-vi-permits/.*

[564] Ibid.

[565] Arnold & Porter. (2023). EPA Provides Increased Transparency in Class VI Permitting Process; Now Incorporated in Update to Interactive CCUS State Tracker. *https://www.arnoldporter.com/en/perspectives/blogs/environmental-edge/2023/11/ccus-state-legislative-tracker.*

[566] EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[567] Arizona Department of Environmental Quality. (2024). Underground Injection Control (UIC) Program. *https://azdeq.gov/UIC.*

[568] EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[569] EPA. (2023). Underground Injection Control (UIC) Class VI Grant Program. *https://www.epa.gov/system/files/documents/2023-11/uic-class-vi-grant-fact-sheet.pdf.*

[570] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[571] UIC regulations for Class VI wells authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water. The major components to be included in UIC Class VI permits are detailed further in section VII.C.1.a.i(D)(4).

[572] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 25, 2024. *https://www.epa.gov/uic/table-epas-draft-and-final-class-vi-well-permits* Last updated January 19, 2024.

[573] EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[574] Ibid.

monitor, and mitigate risks associated with induced seismicity in any areas within or surrounding a sequestration site through permit and program requirements, such as site characterization and monitoring, and the requirement for applicants to demonstrate that induced seismic activity will not endanger USDWs.[575] See section VII.C.1.a.i(D)(4)(b) for further discussion of mitigating induced seismicity risk. Although the UIC Class II program does not have specific requirements regarding seismicity, it includes discretionary authority to add additional conditions to a UIC permit on a case-by-case basis. The EPA created a document outlining practical approaches for UIC Directors to use to minimize and manage injection-induced seismicity in Class II wells.[576] Furthermore, during site characterization, if any of the geologic or seismic data obtained indicate a substantial likelihood of seismic activity, further analyses, potential planned operational changes, and additional monitoring may be required.[577] The EPA has the authority to require seismic monitoring as a condition of the UIC permit if appropriate, or to deny the permit if the injection-induced seismicity risk could endanger USDWs.

Comment: Some commenters have expressed concern that the EPA has not meaningfully engaged with historically disadvantaged and overburdened communities who may be impacted by environmental changes due to geologic sequestration.

Response: The EPA acknowledges that meaningful engagement with local communities is an important step in the development of geologic sequestration projects and has programs and public participation requirements in place to support this process. The EPA is committed to advancing environmental justice for overburdened communities in all its programs, including the UIC Class VI program.[578] The EPA's environmental justice guidance for Class VI permitting and primacy states that many of the expectations are broadly applicable, and EPA Regions should apply them to the other five injection well classes, including Class II, wherever possible.[579] See section VII.C.1.a.i(D)(4) for a detailed discussion of environmental justice requirements and guidance.

Comment: Commenters expressed concern that companies are not always in compliance with reporting requirements for subpart RR when required for other Federal programs.

Response: The EPA recognizes the need for geologic sequestration facilities to comply with the reporting requirements of the GHGRP, and acknowledges that there have been instances of entities claiming geologic sequestration under non-EPA programs (*e.g.*, to qualify for IRC section 45Q tax credits) while not having an EPA-approved MRV plan or reporting data under subpart RR.[580] The EPA does not implement the IRC section 45Q tax credit program, and it is not privy to taxpayer information. Thus, the EPA has no role in implementing or enforcing these tax credit claims, and it is unclear, for example, whether these companies would have been required by GHGRP regulations to report data under subpart RR, or if they would have been required only by the IRC section 45Q rules to opt-in to reporting under subpart RR. The EPA disagrees that compliance with the GHGRP would be a problem for this rule because the rule requires any affected unit that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the captured CO_2 underground to report under GHGRP subpart RR or GHGRP subpart VV. Unlike the IRC section 45Q tax credit program, which is implemented by the Internal Revenue Service (IRS), the EPA will have the information necessary to discern whether a facility is in compliance with any applicable GHGRP requirements. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility that reports in accordance with GHGRP subpart RR or GHGRP subpart VV. For more information on the relationship to GHGRP requirements, see section X.C.5 of this preamble.

Comment: Commenters expressed concerns that UIC regulations allow Class II wells to be used for long-term CO_2 storage if the operator assesses that a Class VI permit is not required and asserted that Class II regulations are less protective than Class VI regulations.

Response: The EPA acknowledges that Class II wells for EOR may be used to inject CO_2 including CO_2 captured from an EGU. However, the EPA disagrees that the use of Class II wells for ER will be less protective of human health than the use of Class VI wells for geologic sequestration. Class II wells are used only to inject fluids associated with oil and natural gas production, and Class II ER wells are used specifically for the injection of fluids, including CO_2, for the purpose of enhanced recovery of oil or natural gas. The EPA's UIC Class II program is designed to prevent Class II injection activities from endangering USDWs. Any leakage out of the designated injection zone could pose a risk to USDWs and therefore could be subject to enforcement action or permit modification. Therefore, the EPA believes that UIC protections for USDWs would also ensure that the injected CO_2 is contained in the subsurface formations. The Class II programs of states and tribes must be approved by the EPA and must meet EPA regulatory requirements for Class II programs, 42 U.S.C. 300h–1, or otherwise represent an effective program to prevent endangerment of USDWs. 42 U.S.C 300h–4. The EPA's regulations require the operator of a Class II well to obtain a Class VI permit when operations shift to geologic sequestration and there is consequently an increased risk to USDWs. 40 CFR 144.19. UIC Class VI regulations require that owners or operators must show that the injection zone has sufficient volume to contain the injected carbon dioxide stream and report any fluid migration out of the injection zone and into or between USDWs. 40 CFR 146.83 and 40 CFR 146.91. The EPA emphasizes that while CO_2 captured from an EGU can be injected into a Class II ER injection well, it cannot be injected into the other two types of Class II wells, which are Class II disposal wells and Class II wells for the storage of hydrocarbons. 40 CFR 144.6(b).

Comment: Some commenters expressed concern that because few Class VI permits have been issued, the EPA's current level of experience in properly regulating and reviewing permits for these wells is limited.

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[575] EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[576] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[577] 40 CFR 146.82(a)(3)(v).

[578] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf; see also* EPA. Letter from the EPA Administrator Michael S. Regan to U.S. State Governors. December 9, 2022. *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[579] EPA. (2023). Environmental Justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[580] Letter from U.S. Treasury Inspector General for Tax Administration (TIGTA). (2020). *https://www.menendez.senate.gov/imo/media/doc/TIGTA%20IRC%2045Q%20Response%20Letter%20FINAL%2004-15-2020.pdf.*

Response: The EPA disagrees that the Agency lacks experience to properly regulate, and review permits for Class VI injection wells. We expect that the additional resources that have been allocated for the Class VI program will lead to increased efficiencies in the Class VI permitting process and timeframes. For a more detailed discussion of Class VI permitting and timeframes, see sections VII.C.1.a.i(D)(4)(b) and VII.C.1.a.i(D)(5) of this preamble. The EPA emphasizes that incomplete or insufficient application materials can result in substantially delayed permitting decisions. When the EPA receives incomplete or insufficient permit applications, the EPA communicates the deficiencies, waits to receive additional materials from the applicant, and then reviews any new data. This back and forth can result in longer permitting timeframes. The EPA therefore encourages applicants to contact their permitting authority early on so applicants can gain a thorough understanding of the Class VI permitting process and the permitting authority's expectations. To assist potential permit applicants, the EPA maintains a list of UIC contacts within each EPA Regional Office on the Agency's website.[581] The EPA has met with more than 100 companies and other interested parties.

Comment: Some commenters claimed that various legal uncertainties preclude a finding that geologic sequestration of CO_2 has been adequately demonstrated. This concern has been raised in particular with issues of pore space ownership and the lack of long-term liability insurance and noted uncertainties regarding long-term liability generally.

Response: The EPA disagrees that these uncertainties are sufficient to prohibit the development of geologic sequestration projects. An interagency CCS task force examined sequestration-related legal issues thoroughly and concluded that early CCS projects could proceed under the existing legal framework with respect to issues such as property rights and liability.[582] The development of CCS projects may be more complex in certain regions, due to distinct pore space ownership regulatory regimes at the state level, except on Federal lands.[583]

As discussed in section VII.C.1.a.i.(D)(4) of this preamble, Title V of the FLPMA and its implementing regulations, 43 CFR part 2800, authorize the BLM to issue ROWs to geologically sequester CO_2 in Federal pore space, including BLM ROWs for the necessary physical infrastructure and for the use and occupancy of the pore space itself. The BLM has published a policy defining access to pore space on BLM lands, including clarification of Federal policy for situations where the surface and pore space are under the control of different Federal agencies.[584]

States have established legislation and regulations defining pore space ownership and providing clarification to prospective users of surface pore space. For example, in North Dakota, the surface owner also owns the pore space underlying their surface estate.[585] North Dakota state courts have determined that in situations where the surface ownership and mineral ownership have been legally severed the mineral estate is the dominant estate and has the right to use as much of the surface estate as reasonably necessary. The North Dakota legislature codified this interpretation in 2019.[586] Summit Carbon Solutions, which is developing a carbon storage hub in North Dakota to store an estimated one billion tons of CO_2, indicated that they had secured the majority of the pore space needed through long term leases with landowners.[587] Wyoming defines ownership of pore space underlying surfaces within the state.[588] Other states have also established laws, implementing regulations and guidance defining ownership and access to pore space. The EPA notes that many states are actively enacting legislation addressing pore space ownership. See *e.g.,* Wyoming H.B. No. 89 (2008) (Wyo. Stat. § 34–1–152); Montana S.B. No. 498 (2009) (Mont. Code Ann. 82–11–180); North Dakota S.B. No. 2139 (2009) (N.D. Cent. Code § 47–31–03); Kentucky H.B. 259 (2011) (Ky. Rev. Stat. Ann. § 353.800); West Virginia H.B. 4491 (2022) (W. Va. Code § 22–11B–18); California S.B. No. 905 (2022) (Cal. Pub. Res. Code § 71462); Indiana Public Law 163 (2022) (Ind. Code § 14–39–2–3); Utah H.B. 244 (2022) (Utah Code § 40–6–20.5).

Liability during operation is usually assumed by the project operator, so liability concerns primarily arise after the period of operations. Research has previously shown that the environmental risk is greatest before injection stops.[589] In terms of long-term liability and permittee obligations under the SDWA, the EPA's Class VI regulations impose various requirements on permittees even after injection ceases, including regarding injection well plugging (40 CFR 146.92), post-injection site care (PISC), and site closure (40 CFR 146.93). The default time period for post-injection site care is 50 years, during which the permittee must monitor the position of the CO_2 plume and pressure front and demonstrate that USDWs are not being endangered. 40 CFR 146.93. The permittee must also generally maintain financial responsibility sufficient to cover injection well plugging, corrective action, emergency and remedial response, PISC, and site closure until the permitting authority approves site closure. 40 CFR 146.85(a)&(b). Even after the former permittee has fulfilled all its UIC regulatory obligations, it may still be held liable for previous regulatory noncompliance, such as where the permittee provided erroneous data to support approval of site closure. A former permittee may always be subject to an order that the EPA Administrator deems necessary to protect public health if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW. 42 U.S.C. 300i; 40 CFR 144.12(e).

The EPA notes that many states are enacting legislation addressing long term liability. See *e.g.,* Montana S.B. No. 498 (2009) (Mont. Code Ann. 82–11–183); Texas H.B. 1796 (2009) (Tex. Health & Safety Code Ann. § 382.508); North Dakota S.B. No. 2095 (2009) (N.D. Cent. Code § 38–22–17); Kansas H.B.

[581] EPA. (2023). Underground Injection Control Class VI (Geologic Sequestration) Contact Information. *https://www.epa.gov/uic/underground-injection-control-class-vi-geologic-sequestration-contact-information.*

[582] Report of the Interagency Task Force on Carbon Capture and Storage. 2010. *https://www.energy.gov/fecm/articles/ccstf-final-report.*

[583] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[584] National Policy for the Right-of-Way Authorizations Necessary for Site Characterization, Capture, Transportation, Injection, and Permanent Geologic Sequestration of Carbon Dioxide in Connection with Carbon Sequestration Projects. BLM IM 2022–041 Instruction Memorandum, June 8, 2022. *https://www.blm.gov/policy/im-2022-041.*

[585] ND DMR 2023. Pore Space in North Dakota. North Dakota Department of Mineral Resources *https://www.dmr.nd.gov/oilgas/ND_DMR_Pore_Space_Information.pdf.*

[586] Ibid.

[587] Summit Carbon Solutions. (2021). Summit Carbon Solutions Announces Significant Carbon Storage Project Milestones. (2021). *https://summitcarbonsolutions.com/summit-carbon-solutions-announces-significant-carbon-storage-project-milestones/.*

[588] Wyo. Stat § 34–1–152 (2022).

[589] Benson, S.M. (2007). Carbon dioxide capture and storage: research pathways, progress and potential. Presentation given at the Global Climate & Energy Project Annual Symposium, October 1, 2007. *https://drive.google.com/file/d/1ZvfRW92OqvBBAFs69SPHIWoYFGySMgtD/view.*

2418 (2010) (Kan. Stat. Ann. § 55–1637(h)); Wyoming S.F. No. 47 (2022) (Wyo. Stat. §§ 35–11–319); Louisiana H.B. 661 (2009) & H.B. 571 (2023) (La. Stat. Ann. § 30:1109). Because states are actively working to address pore space and liability uncertainties, the EPA does not believe these to be issues that would delay project implementation beyond the timelines discussed in this preamble.

(E) Compliance Date for Long-Term Coal-Fired Steam Generating Units

The EPA proposed a January 1, 2030 compliance date for long-term coal fired steam generating units subject to a CCS BSER. That compliance date assumed installation of CCS was concurrent with development of state plans. While several commenters were supportive of the proposed compliance date, the EPA also received comments on the proposed rule that stated that the proposed compliance date was not achievable. Commenters referenced longer project timelines for CO_2 capture. Commenters also requested that the EPA should account for the state plan process in determining the appropriate compliance date.

The EPA has considered the comments and information available and is finalizing a compliance date of January 1, 2032, for long-term coal-fired steam generating units. The EPA is also finalizing a mechanism for a 1-year compliance date extension in cases where a source faces delays outside its control, as detailed in section X.C.1.d of this preamble. The justification for the January 1, 2032 compliance date does not require substantial work to be done during the state planning process. Rather, the justification for the compliance date reflects the assumption that only the initial feasibility work which is necessary to inform the state planning process would occur during state plan development, with the start of more substantial work beginning after the due date for state plan submission, and a longer timeline for installation of CCS than at proposal. In total, this allows for 6 years and 7 months for both initial feasibility and more substantial work to occur after issuance of this rule. This is consistent with the approximately 6 years from start to finish for Boundary Dam Unit 3 and Petra Nova.

The timing for installation of CCS on existing coal-fired steam generating units is based on the baseline project schedule for the CO_2 capture plant developed by Sargent and Lundy (S&L[590] and a review of the available information for installation of CO_2 pipelines and sequestration sites.[591] Additional details on the timeline are in the TSD *GHG Mitigation Measures for Steam Generating Units,* available in the docket. The dates for intermediate steps are for reference. The specific sequencing of steps may differ slightly, and, for some sources, the duration of one step may be shorter while another may be longer, however the total duration is expected to be the same. The resulting timeline is therefore an accurate representation of the time necessary to install CCS in general.

The EPA assumes that feasibility work, amounting to less than 1 year (June 2024 through June 2025) for each component of CCS (capture, transport, and storage) occurs during the state plan development period (June 2024 through June 2026). This feasibility work is limited to initial conceptual design and other preliminary tasks, and the costs of the feasibility work in general are substantially less than other components of the project schedule. The EPA determined that it was appropriate to assume that this work would take place during the state plan development period because it is necessary for evaluating the controls that the state may determine to be appropriate for a source and is necessary for determining the resulting standard of performance that the state may apply to the source on the basis of those controls. In other words, without such feasibility and design work, it would be very difficult for a state to determine whether CCS is appropriate for a given source or the resulting standard of performance. While the EPA accounts for up to 1 year for feasibility for the capture plant, the S&L baseline schedule estimates this initial design activity can be completed in 6 months. For the capture plant, feasibility includes a preliminary technical evaluation to review the available utilities and siting footprint for the capture plant, as well as screening of the available capture technologies and vendors for the project, with an associated initial economic estimate. For sequestration, in many cases, general geologic characterization of regional areas has already been conducted by U.S. DOE and regional initiatives; however, the EPA assumes an up to 1 year period for a storage complex feasibility study. For the pipeline, the feasibility includes the initial pipeline routing analysis, taking less than 1 year. This exercise involves using software to review existing right-of-way and other considerations to develop an optimized pipeline route. Inputs to that analysis have been made publicly available by DOE in NETL's Pipeline Route Planning Database.[592]

When state plans are submitted 24 months after publication of the final rule, requirements included within those state plans should be effective at the state level. On that basis, the EPA assumes that sources installing CCS are fully committed, and more substantial work (*e.g.,* FEED study for the capture plant, permitting, land use and right-of-way acquisition) resumes in June 2026. The EPA notes, however, that it would be possible that a source installing CCS would choose to continue these activities as soon as the initial feasibility work is completed even if not yet required to do so, rather than wait for state plan submission to occur for the reasons explained in full below.

Of the components of CCS, the CO_2 capture plant is the more technically involved and time consuming, and therefore is the primary driver for determining the compliance date. The EPA assumes substantial work commences only after submission due date for state plans. The S&L baseline timeline accounts for 5.78 years (301 weeks) for final design, permitting, and installation of the CO_2 capture plant. First, the EPA describes the timeline that is consistent with the S&L baseline for substantial work. Subsequently, the EPA describes the rationale for slight adjustments that can be made to that timeline based upon an examination of actual project timelines.

In the S&L baseline, substantial work on the CO_2 capture plant begins with a 1-year FEED study (June 2026 to June 2027). The information developed in the FEED study is necessary for finalizing commercial arrangements. In the S&L baseline, the commercial arrangements can take up to 9 months (June 2027 to March 2028). Commercial arrangements include finalizing funding as well as finalizing contracts with a CO_2 capture technology provider and engineering, procurement, and construction companies. The S&L baseline accounts for 1 year for permitting, beginning when commercial arrangements are nearly complete (December 2027 to December 2028). After commercial arrangements are complete, a 2-year period for engineering and procurement begins (March 2028 to March 2030).

[590] CO_2 Capture Project Schedule and Operations Memo, Sargent & Lundy (2024). Available in Docket ID EPA–HQ–OAR–2023–0072.

[591] Transport and Storage Timeline Summary, ICF (2024). Available in Docket ID EPA–HQ–OAR–2023–0072.

[592] NETL Develops Pipeline Route Planning Database To Guide CO_2 Transport Decisions. May 31, 2023. *https://netl.doe.gov/node/12580.*

Detailed engineering starts after commercial arrangements are complete because engineers must consider details regarding the selected CO_2 capture technology, equipment providers, and coordination with construction. Shortly after permitting is complete, 6 months of sitework (March 2029 to September 2029) occur. Sitework is followed by 2 years of construction (July 2029 to July 2031). Approximately 8 months prior to the completion of construction, a roughly 14 month (60 weeks) period for startup and commissioning begins (January 2031 to March 2032).

In many cases, the EPA believes that sources are positioned to install CO_2 capture on a slightly faster timeline than the baseline S&L timeline detailed in the prior paragraph, because CCS projects have been developed in a shorter timeframe. Including these minor adjustments, the total time for detailed engineering, procurement, construction, startup and commissioning is 4 years, which is consistent with completed projects (Boundary Dam Unit 3 and Petra Nova) and project schedules developed in completed FEED studies, see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional details. In addition, the IRC tax credits incentivize sources to begin complying earlier to reap economic benefits earlier. Sources that have already completed feasibility or FEED studies, or that have FEED studies ongoing are likely to be able to have CCS fully operational well in advance of January 1, 2032. Ongoing projects have planned dates for commercial operation that are much earlier. For example, Project Diamond Vault has plans to be fully operational in 2028.[593] While the EPA assumes FEED studies start after the date for state plan submission, in practice sources are likely to install CO_2 capture as expeditiously as practicable. Moreover, the preceding timeline is derived from project schedules developed in the absence of any regulatory impetus. Considering these factors, sources have opportunities to slightly condense the duration, overlap, or sequencing of steps so that the total duration for completing substantial work on the capture plant is reduced by 2 months. For example, by expediting the duration for commercial arrangements from 9 months to 7 months, reasonably assuming sources immediately begin sitework as soon as permitting is complete, and accounting for 13 months (rather than 14) for startup and testing, the CO_2 capture plant will be fully operational by January 2032. Therefore, the EPA concludes that CO_2 capture can be fully operational by January 1, 2032. To the extent additional time is needed to take into account the particular circumstances of a particular source, the state may take those circumstances into account to provide a different compliance schedule, as detailed in section X.C.2 of this preamble.

The EPA also notes that there is additional time for permitting than described in the S&L baseline. The key permitting that affects the timeline are air permits because of the permits' impact on the ability to construct and operate the CCS capture equipment, in which the EPA is the expert in. The S&L baseline assumes permitting starts after the FEED study is complete while commercial arrangements are ongoing, however permitting can begin earlier allowing a more extended period for permitting. Examples of CCS permitting being completed while FEED studies are on-going include the air permits for Project Tundra, Baytown Energy Center, and Deer Park Energy Center. Therefore, while the FEED study is on-going, the EPA assumes that a 2-year process for permitting can begin.

The EPA's compliance deadline assumes that storage and pipelines for the captured CO_2 can be installed concurrently with deployment of the capture system. Substantial work on the storage site starts with 3 years (June 2026 to June 2029) for final site characterization, pore-space acquisition, and permitting, including at least 2 years for permitting of Class VI wells during that period. Lastly, construction for sequestration takes 1 year (June 2029 to June 2030). While the EPA assumes that storage can be permitted and constructed in 4 years, the EPA notes that there is at least an additional 12 months of time available to complete construction of the sequestration site without impacting progress of the other components.

The EPA assumes the substantial work on the pipeline lags the start of substantial work on the storage site by 6 months. After the 1 year of feasibility work prior to state plan submission, the general timeline for the CO_2 pipeline assumes up to 3 years for final routing, permitting activities, and right-of-way acquisition (December 2026 to December 2029). Lastly, there are 1.5 years for pipeline construction (December 2029 to June 2031).[594]

The EPA does not assume that CCS projects are, in general, subject to NEPA. NEPA review is required for reasons including sources receiving federal funding (*e.g.*, through USDA or DOE) or projects on federal lands. NEPA may also be triggered for a CCS project if NEPA compliance is necessary for construction of the pipeline, such as where necessary because of a Clean Water Act section 404 permit, or for sequestration. Generally, if one aspect of a project is subject to NEPA, then the other project components could be as well. In cases where a project is subject to NEPA, an environmental assessment (EA) that takes 1 year, can be finalized concurrently during the permitting periods of each component of CCS (capture, pipeline, and sequestration). However, the EPA notes that the final timeline can also accommodate a concurrent 2-year period if an EIS were required under NEPA across all components of the project. The EPA also notes that, in some circumstances, NEPA review may begin prior to completion of a FEED study. For Petra Nova, a notice of intent to issue an EIS was published on November 14, 2011, and the record of decision was issued less than 2 years later, on May 23, 2013,[595] while the FEED study was completed in 2014.

Based on this detailed analysis, the EPA has concluded that January 1, 2032, is an achievable compliance date for CCS on existing coal-fired steam generating units that takes into account the state plan development period, as well as the technical and bureaucratic steps necessary to install and implement CCS and is consistent with other expert estimates and real-world experience.

(F) Long-Term Coal-Fired Steam Generating Units Potentially Subject to This Rule

In this section of the preamble, the EPA estimates the size of the inventory of coal-fired power plants in the long-term subcategory likely subject to CCS as the BSER. Considering that capacity, the EPA also describes the distance to storage for those sources.

(1) Capacity of Units Potentially Subject to This Rule

First, the EPA estimates the total capacity of units that are currently operating and that have not announced plans to retire by 2039, or to cease firing

[593] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[594] The summary timeline for CO_2 pipelines assumes feasibility for pipelines is 1 year, followed by 1.5 years for permitting, with the pipeline feasibility beginning 1 year after permitting for sequestration starts. The EPA assumes initial pipeline feasibility occurs up-front, with a longer period for final routing, permitting, and right-of-way acquisition.

[595] Petra Nova W.A. Parish Project. *https://www.energy.gov/fecm/petra-nova-wa-parish-project.*

coal by 2030. Starting from that first estimate, the EPA then estimates the capacity of units that would likely be subject to the CCS requirement, based on unit age, industry trends, and economic factors.

Currently, there are 181 GW of coal-fired steam generating units.[596] About half of that capacity, totaling 87 GW, have announced plans to retire before 2039, and an additional 13 GW have announced plans to cease firing coal by that time. The remaining amount, 81 GW, are likely to be the most that could potentially be subject to requirements based on CCS.

However, the capacity of affected coal-fired steam generating units that would ultimately be subject to a CCS BSER is likely approximately 40 GW. This determination is supported by several lines of analysis of the historical data on the size of the fleet over the past several years. Historical trends in the coal-fired generation fleet are detailed in section IV.D.3 of this preamble. As coal-fired units age, they become less efficient and therefore the costs of their electricity go up, rendering them even more competitively disadvantaged. Further, older sources require additional investment to replace worn parts. Those circumstances are likely to continue through the 2030s and beyond and become more pronounced. These factors contribute to the historical changes in the size of the fleet.

One way to analyze historical changes in the size of the fleet is based on unit age. As the average age of the coal-fired fleet has increased, many sources have ceased operation. From 2000 to 2022, the average age of a unit that retired was 53 years. At present, the average age of the operating fleet is 45 years. Of the 81 GW that are presently operating and that have not announced plans to retire or convert to gas prior to 2039, 56 GW will be 53 years or older by 2039.[597]

Another line of analysis is based on the rate of change of the size of the fleet. The final TSD, *Power Sector Trends*, available in the rulemaking docket, includes analysis showing sharp and steady decline in the total capacity of the coal-fired steam generating fleet. Over the last 15 years (2009–2023), average annual coal retirements have been 8 GW/year. Projecting that retirements will continue at approximately the same pace from now until 2039 is reasonable because the same circumstances will likely continue or accelerate further given the incentives under the IRA. Applying this level of annual retirement would result in 45 GW of coal capacity continuing to operate by 2039. Alternatively, the TSD also includes a graph that shows what the fleet would look like assuming that coal units without an announced retirement date retire at age 53 (the average retirement age of units over the 2000–2022 period). It shows that the amount of coal-fired capacity that remains in operation by 2039 is 38 GW.

The EPA also notes that it is often the case that coal-fired units announce that they plan to retire only a few years in advance of the retirement date. For instance, of the 15 GW of coal-fired EGUs that reported a 2022 retirement year in DOE's EIA Form 860, only 0.5 GW of that capacity had announced its retirements plans when reporting in to the same EIA–860 survey 5 years earlier, in 2017.[598] Thus, although many coal-fired units have already announced plans to retire before 2039, it is likely that many others may anticipate retiring by that date but have not yet announced it.

Finally, the EPA observes that modeling the baseline circumstances, absent this final rule, shows additional retirements of coal-fired steam generating units. At the end of 2022, there were 189 GW of coal active in the U.S. By 2039, the IPM baseline projects that there will be 42 GW of operating coal-fired capacity (not including coal-to-gas conversions). Between 2023–2039, 95 GW of coal capacity have announced retirement and an additional 13 have announced they will cease firing coal. Thus, of the 81 GW that have not announced retirement or conversion to gas by 2039, the IPM baseline projects 39 GW will retire by 2039 due to economic reasons.

For all these reasons, the EPA considers that it is realistic to expect that 42 GW of coal-fired generating will be operating by 2039—based on announced retirements, historical trends, and model projections—and therefore constitutes the affected sources in the long-term subcategory that would be subject to requirements based on CCS. It should be noted that the EPA does not consider the above analysis to predict with precision which units will remain in operation by 2039. Rather, the two sets of sources should be considered to be reasonably representative of the inventory of sources that are likely to remain in operation by 2039, which is sufficient for purposes of the BSER analysis that follows.

(2) Distance to Storage for Units Potentially Subject to This Rule

The EPA believes that it is conservative to assume that all 81 GW of capacity with planned operation during or after 2039 would need to construct pipelines to connect to sequestration sites. As detailed in section VII.B.2 of this preamble, the EPA is finalizing an exemption for coal-fired sources permanently ceasing operation by January 1, 2032. About 42 percent (34 GW) of the existing coal-fired steam generation capacity that is currently in operation and has not announced plans to retire prior to 2039 will be 53 years or older by 2032. As discussed in section VII.C.1.a.i(F), from 2000 to 2022, the average age of a coal unit that retired was 53 years old. Therefore, the EPA anticipates that approximately 34 GW of the total capacity may permanently cease operation by 2032 despite not having yet announced plans to do so. Furthermore, of the coal-fired steam generation capacity that has not announced plans to cease operation before 2039 and is further than 100 km (62 miles) of a potential saline sequestration site, 45 percent (7 GW) will be over 53 years old in 2032. Therefore, it is possible that much of the capacity that is further than 100 km (62 miles) of a saline sequestration site and has not announced plans to retire will permanently cease operation due to age before 2032 and thus the rule would not apply to them. Similarly, of the coal-fired steam generation capacity that has not announced plans to cease operation before 2039 and is further than 160 km (100 miles) of a potential saline sequestration site, 56 percent (4 GW) will be over 53 years old in 2032. Therefore, the EPA notes that it is possible that the majority of capacity that is further than 160 km (100 miles) of a saline sequestration and has not announced plans to retire site will permanently cease operation due to age before 2032 and thus be exempt from the requirements of this rule.

The EPA also notes that a majority (56 GW) of the existing coal-fired steam generation capacity that is currently in operation and has not announced plans to permanently cease operation prior to 2039 will be 53 years or older by 2039. Of the coal-fired steam generation capacity with planned operation during

[596] EIA December 2023 Preliminary Monthly Electric Generator Inventory. *https://www.eia.gov/electricity/data/eia860m/*.

[597] 81 GW is derived capacity, plant type, and retirement dates as represented in EPA NEEDS database. Total amount of covered capacity in this category may ultimately be slightly less (approximately) due to CHP-related exemptions.

[598] The survey Form EIA–860 collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater of combined nameplate capacity. Data available at *https://www.eia.gov/electricity/data/eia860/*.

or after 2039 that is not located within 100 km (62 miles) of a potential saline sequestration site, the majority (58 percent or 9 GW) of the units will be 53 years or older in 2039.[599] Consequently, the EPA believes that many of these units may permanently cease operation due to age prior to 2039 despite not at this point having announced specific plans to do so, and thereby would likely not be subject to a CCS BSER.

(G) Resources and Workforce To Install CCS

Sufficient resources and an available workforce are required for installation and operation of CCS. Raw materials necessary for CCS are generally available and include common commodities such as steel and concrete for construction of the capture plant, pipelines, and storage wells.

Drawing on data from recently published studies, the DOE completed an order-of-magnitude assessment of the potential requirements for specialized equipment and commodity materials for retrofitting existing U.S. coal-fueled EGUs with CCS.[600] Specialized equipment analyzed included absorbers, strippers, heat exchangers, and compressors. Commodity materials analyzed included monoethanolamine (MEA) solvent for carbon capture, triethylene glycol (TEG) for carbon dioxide drying, and steel and cement for construction of certain aspects of the CCS value chain.[601] The DOE analyzed one scenario in which 42 GW of coal-fueled EGUs are retrofitted with CCS and a second scenario in which 73 GW of coal-fueled EGUs are retrofitted with CCS.[602] The analysis determined that in both scenarios, the maximum annual commodity requirements to construct and operate the CCS systems are likely to be much less than their respective global production rates. The maximum requirements are expected to be at least one order of magnitude lower than global annual production for all of the commodities considered except MEA, which was estimated to be approximately 14 percent of global annual production in the 42 GW scenario and approximately 24 percent of global annual production in the 73 GW scenario.[603] For steel and cement, the maximum annual requirements are also expected to be at least one order of magnitude lower than U.S. annual production rates. Finally, the DOE analysis determined that it is unlikely that the deployment scenarios would encounter any bottlenecks in the supplies of specialized equipment (absorbers, strippers, heat exchangers, and compressors) because of the large pool of potential suppliers.

The workforce necessary for installing and operating CCS is readily available. The required workforce includes construction, engineering, manufacturing, and other skilled labor (*e.g.*, electrical, plumbing, and mechanical trades). The existing workforce is well positioned to meet the demand for installation and operation of CCS. Many of the skills needed to build and operate carbon capture plants are similar to those used by workers in existing industries, and this experience can be leveraged to support the workforce needed to deploy CCS. In addition, government programs, industry workforce investments, and IRC section 45Q prevailing wage and apprenticeship provisions provide additional significant support to workforce development and demonstrate that the CCS industry likely has the capacity to train and expand the available workforce to meet future needs.[604]

Overall, quantitative estimates of workforce needs indicates that the total number of jobs needed for deploying CCS on coal power plants is significantly less than the size of the existing workforce in adjacent occupations with transferrable skills in the electricity generation and fuels industries. The majority of direct jobs, approximately 90 percent, are expected to be in the construction of facilities, which tend to be project-based. The remaining 10 percent of jobs are expected to be tied to ongoing facility operations and maintenance.[605] Recent project-level estimates bear this out. The Boundary Dam CCS facility in Canada employed 1,700 people at peak construction.[606] A recent workforce projection estimates average annual jobs related to investment in carbon capture retrofits at coal power plants could range from 1,070 to 1,600 jobs per plant. A DOE memorandum estimates that 71,400 to 107,100 average annual jobs resulting from CCS project investments—across construction, project management, machinery installers, sales representatives, freight, and engineering occupations—would likely be needed over a five-year construction period [607] to deploy CCS at

[599] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation available at:. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[600] DOE. Material Requirements for Carbon Capture and Storage Retrofits on Existing Coal-Fueled Electric Generating Units. *https://www.energy.gov/policy/articles/material-requirements-carbon-capture-and-storage-retrofits-existing-coal-fueled.*

[601] Steel requirements were assessed for carbon capture, transport and storage, but cement requirements were only assessed for capture and storage.

[602] DOE analyzed the resources—including specialized equipment, commodity materials, and, as discussed below, workforce, necessary for 73 GW of coal capacity to install CCS because that is the amount that has not announced plans to retire by January 1, 2040. As indicated in the final TSD, *Power Sector Trends,* a somewhat larger amount—81 GW—has not announced plans to retire or cease firing coal by January 1, 2039, and it is this latter amount that is the maximum that, at least in theory, could be subject to the CCS requirement. DOE's conclusions that sufficient resources are available also hold true for the larger amount.

[603] Although the assessment assumed that all of the CCS deployments would utilize MEA-based carbon capture technologies, future CCS deployments could potentially use different solvents, or capture technologies that do not use solvents, *e.g.,* membranes, sorbents. A number of technology providers have solvents that are commercially available, as detailed in section VII.C.1.a.i.(B)(3) of this preamble. In addition, a 2022 DOE carbon capture supply chain assessment concluded that common amines used in carbon capture have robust and resilient supply chains that could be rapidly scaled, with low supply chain risk associated with the main inputs for scale-up. See U.S. Department of Energy (DOE). Supply Chain Deep Dive Assessment: Carbon Capture, Transport & Storage. *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf.*

[604] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits.*

[605] Ibid.

[606] SaskPower, ''SaskPower CCS.'' *https://unfccc.int/files/bodies/awg/application/pdf/01_saskatchewan_environment_micheal_monea.pdf.* For corroboration, we note similar employment numbers for two EPAct-05 assisted projects: Petra Nova estimated it would need approximately 1,100 construction-related jobs and up to 20 jobs for ongoing operations. National Energy Technology Laboratory and U.S. Department of Energy. W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Final Environmental Impact Statement. *https://www.energy.gov/sites/default/files/EIS-0473-FEIS-Summary-2013_1.pdf.* Project Tundra projects a peak labor force of 600 to 700. National Energy Technology Laboratory and U.S. Department of Energy. Draft Environmental Assessment for North Dakota CarbonSAFE: Project Tundra. *https://www.energy.gov/sites/default/files/2023-08/draft-ea-2197-nd-carbonsafe-chapters-2023-08.pdf.*

[607] For the purposes of evaluating the actual workforce and resources necessary for installation of CCS, the five-year assumption in the DOE memo is reasonable. The representative timeline for CCS includes an about 3-year period for construction activities (including site work, construction, and startup and testing) across the components of CCS (capture, pipeline, and sequestration), beginning at the end of 2028. Many sources are well positioned to install CCS, having already completed feasibility work, FEED studies, and/or permitting, and could thereby reasonably start construction activities (still 3-years in duration) by the beginning of 2028 or earlier and, as a practical matter, would likely do so notwithstanding the requirements of this rule

Continued

a subset of coal power plants. The memorandum further estimates that 116,200 to 174,300 average annual jobs would likely be needed if CCS were deployed at all coal-fired EGUs that currently have no firm commitment to retire or convert to natural gas by 2040.[608] For comparison, the DOE memorandum further categorizes potential workforce needs by occupation, and estimates 11,420 to 27,890 annual jobs for construction trade workers, while the U.S. Energy and Employment Report estimates that electric power generation and fuels accounted for more than 292,000 construction jobs in 2022, which is an order of magnitude greater than the potential workforce needs for CCS deployment under this rule. Overall energy-related construction activities across the entire energy industry accounted for nearly 2 million jobs, or 25 percent of all construction jobs in 2022, indicating that there is a very large pool of workers potentially available.[609]

As noted in section VII.C.1.a.i(F), the EPA determined that the population of sources without announced plans to cease operation or discontinue coal-firing by 2039, and that is therefore potentially subject to a CCS BSER, is not more than 81 GW, as indicated in the final TSD, *Power Sector Trends.* The DOE CCS Commodity Materials and Workforce Memos evaluated material resource and workforce needs for a similar capacity (about 73 GW), and determined that the resources and workforce available are more than sufficient, in most cases by an order of magnitude. Considering these factors, and the similar scale of the population of sources considered, the EPA therefore concludes that the workforce and resources available are more than sufficient to meet the demands of coal-fired steam generating units potentially subject to a CCS BSER.

(H) Determination That CCS Is "Adequately Demonstrated"

As discussed in detail in section V.C.2.b, pursuant to the text, context, legislative history, and judicial precedent interpreting CAA section 111(a)(1), a technology is "adequately demonstrated" if there is sufficient evidence that the EPA may reasonably conclude that a source that applies the technology will be able to achieve the associated standard of performance under the reasonably expected operating circumstances. Specifically, an adequately demonstrated standard of performance may reflect the EPA's reasonable expectation of what that particular system will achieve, based on analysis of available data from individual commercial scale sources, and, if necessary, identifying specific available technological improvements that are expected to improve performance.[610] The law is clear in establishing that at the time a section 111 rule is promulgated, the system that the EPA establishes as BSER need not be in widespread use. Instead, the EPA's responsibility is to determine that the demonstrated technology can be implemented at the necessary scale in a reasonable period of time, and to base its requirements on this understanding.

In this case, the EPA acknowledged in the proposed rule, and reaffirms now, that sources will require some amount of time to install CCS. Installing CCS requires the building of capture facilities and pipelines to transport captured CO_2 to sequestration sites, and the development of sequestration sites. This is true for both existing coal plants, which will need to retrofit CCS, and new gas plants, which must incorporate CCS into their construction planning. As the EPA explained at proposal, D.C. Circuit caselaw supports this approach.[611] Moreover, the EPA has determined that there will be sufficient resources for all coal-fired power plants that are reasonably expected to be operating as of January 1, 2039, to install CCS. Nothing in the comments alters the EPA's view of the relevant legal requirements related to the EPA's determination of time necessary to allow for adoption of the system.

With all of the above in mind, the preceding sections show that CCS technology with 90 percent capture is clearly adequately demonstrated for coal-fired steam generating units, that the 90 percent standard is achievable,[612] and that it is reasonable for the EPA to determine that CCS can be deployed at the necessary scale in the compliance timeframe.

(1) EPAct05

In the proposal, the EPA noted that in the 2015 NSPS, the EPA had considered coal-fired industrial projects that had installed at least some components of CCS technology. In doing so, the EPA recognized that some of those projects had received assistance in the form of grants, loan guarantees, and Federal tax credits for investment in "clean coal technology," under provisions of the Energy Policy Act of 2005 ("EPAct05"). See 80 FR 64541–42 (October 23, 2015). (The EPA refers to projects that received assistance under that legislation as "EPAct05-assisted projects.") The EPA further recognized that the EPAct05 included provisions that constrained how the EPA could rely on EPAct05-assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111.[613]

given the strong economic incentives provided by the tax credit. The representative timeline also makes conservative assumptions about the pre-construction activities for pipelines and sequestration, and for many sources construction of those components could occur earlier. Finally, to provide greater regulatory certainty and incentivize the installation of controls, the EPA is finalizing a limited one-year compliance date extension mechanism for certain circumstances as detailed in section X.C.1.d of the preamble, and it would also be reasonable to assume that, in practice, some sources use that mechanism. Considering these factors, evaluating workforce and resource requirements over a five-year period is reasonable.

[608] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits.*

[609] U.S. Department of Energy. United States Energy & Employment Report 2023. *https://www.energy.gov/sites/default/files/2023-06/2023%20USEER%20REPORT-v2.pdf.*

[610] A line of cases establishes that the EPA may extrapolate based on its findings and project technological improvements in a variety of ways. First, the EPA may reasonably extrapolate from testing results to predict a lower emissions rate than has been regularly achieved in testing. *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973). Second, the EPA may forecast technological improvements allowing a lower emissions rate or effective control at larger plants than those previously subject to testing, provided the agency has adequate knowledge about the needed changes to make a reasonable prediction. *See Sierra Club* v. *Costle* 657 F.2d 298 (1981). Third, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different, related, source. *See Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[611] There, EPA cited *Portland Cement* v. *Ruckelshaus,* for the proposition that "D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the 'adequately demonstrated' criterion—even if the controls require some amount of 'lead time,' which the court has defined as 'the time in which the technology will have to be available.' " *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 FR 33240, 33289 (May 23, 2023) (quoting *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973)).

[612] The concepts of "adequately demonstrated" and "achievable" are closely related. As the D.C. Circuit explained in *Essex Chem. Corp.* v. *Ruckelshaus,* "[i]t is the *system* which must be adequately demonstrated and the *standard* which must be achievable." 486 F.2d 427, 433 (1973).

[613] The relevant EPAct05 provisions include the following: Section 402(i) of the EPAct05, codified at 42 U.S.C. 15962(a), provides as follows: "No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [] for purposes of section 111 of the Clean Air Act. . . ." IRC section 48A(g), as added by EPAct05

In the 2015 NSPS, the EPA went on to provide a legal interpretation of those constraints. Under that legal interpretation, ''these provisions [in the EPAct05] . . . preclude the EPA from relying solely on the experience of facilities that received [EPAct05] assistance, but [do] not . . . preclude the EPA from relying on the experience of such facilities in conjunction with other information.''[614] *Id.* at 64541–42. In this action, the EPA is adhering to the interpretation of these provisions that it announced in the 2015 NSPS.

Some commenters criticized the legal interpretation that the EPA advanced in the 2015 NSPS, and others supported the interpretation. The EPA has responded to these comments in the Response to Comments Document, available in the docket for this rulemaking.

ii. Costs

The EPA has analyzed the costs of CCS for existing coal-fired long-term steam generating units, including costs for CO_2 capture, transport, and sequestration. The EPA has determined costs of CCS for these sources are reasonable. The EPA also evaluated costs assuming shorter amortization periods. As elsewhere in this section of the preamble, costs are presented in 2019 dollars. In sum, the costs of CCS are reasonable under a variety of metrics. The costs of CCS are reasonable as compared to the costs of other controls that the EPA has required for these sources. And the costs of CCS are reasonable when looking to the dollars per ton of CO_2 reduced. The reasonableness of CCS as an emission control is further reinforced by the fact that some sources are projected to install CCS even in the absence of any EPA rule addressing CO_2 emissions—11 GW of coal-fired EGUs install CCS in the modeling base case.

Specifically, the EPA assessed the average cost of CCS for the fleet of coal-fired steam generating units with no announced retirement or gas conversion prior to 2039. In evaluating costs, the EPA accounts for the IRC section 45Q tax credit of $85/metric ton (assumes prevailing wage and apprenticeship requirements are met), a detailed discussion of which is provided in section VII.C.1.a.ii(C) of this preamble. The EPA also accounts for increases in utilization that will occur for units that apply CCS due to the incentives provided by the IRC section 45Q tax credit. In other words, because the IRC section 45Q tax credit provides a significant economic benefit, sources that apply CCS will have a strong economic incentive to increase utilization and run at higher capacity factors than occurred historically. This assumption is confirmed by the modeling, which projects that sources that install CCS run at a high capacity factor—generally, about 80 percent or even higher. The EPA notes that the NETL Baseline study assumes 85 percent as the default capacity factor assumption for coal CCS retrofits, noting that coal plants in market conditions supporting baseload operation have demonstrated the ability to operate at annual capacity factors of 85 percent or higher.[615] This assumption is also supported by observations of wind generators who receive the IRC section 45 production tax credit who continue to operate even during periods of negative power prices.[616] Therefore, the EPA assessed the costs for CCS retrofitted to existing coal-fired steam generating units assuming an 80 percent annual capacity factor. Assuming an 80 percent capacity factor and 12-year amortization period,[617] the average costs of CCS for the fleet are −$5/ton of CO_2 reduced or −$4/MWh of generation. Assuming at least a 12-year amortization period is reasonable because any unit that installs CCS and seeks to maximize its profitability will be incentivized to recoup the full value of the 12-year tax credit.

Therefore for long-term coal-fired steam generating units—ones that operate after January 1, 2039—the costs of CCS are similar or better than the representative costs of controls detailed in section VII.C.1.a.ii(D) of this preamble (*i.e.*, costs for SCRs and FGDs on EGUs of $10.60 to $18.50/MWh and the costs in the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category of $98/ton of CO_2e reduced (80 FR 56627; September 18, 2015)).

The EPA also evaluated the costs for shorter amortization periods, considering the $/MWh and $/ton metrics, as well as other cost indicators, as described in section VII.C.1.a.ii.(D). Specifically, with an initial compliance date of January 1, 2032, sources operating through the end of 2039 have at least 8 years to amortize costs. For an 80 percent capacity factor and an 8-year amortization period, the average costs of CCS for the fleet are $19/ton of CO_2 reduced or $18/MWh of generation; these costs are comparable to those costs that the EPA has previously determined to be reasonable. Sources operating through the end of 2040, 2041, and beyond (*i.e.*, sources with 9, 10, or more years to amortize the costs of CCS) have even more favorable average costs per MWh and per ton of CO_2 reduced. Sources ceasing operation by January 1, 2039, have 7 years to amortize costs. For an 80 percent capacity factor and a 7-year amortization period, the fleet average costs are $29/ton of CO_2 reduced or $28/MWh of generation; these average costs are less comparable on a $/MWh of generation basis to those costs the EPA has previously determined to be reasonable, but substantially lower than costs the EPA has previously determined to be reasonable on a $/ton of CO_2 reduced basis. The EPA further notes that the costs presented are average costs for the fleet. For a substantial amount of capacity, costs assuming a 7-year amortization period are comparable to those costs the EPA has previously determined to be reasonable on both a $/MWh basis (*i.e.*, less than $18.50/MWh) and a $/ton basis (*i.e.* less than $98/ton CO2e),[618] and the EPA concludes that a substantial amount of capacity can install CCS at reasonable cost with a 7-year amortization

1307(b), provides as follows: ''No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is adequately demonstrated [] for purposes of section 111 of the Clean Air Act. . . .'' Section 421(a) states: ''No technology, or level of emission reduction, shall be treated as adequately demonstrated for purpose [*sic*] of section 7411 of this title, . . . solely by reason of the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under section 13572(a)(1) of this title.''

[614] In the 2015 NSPS, the EPA adopted several other legal interpretations of these EPAct05 provisions as well. See 80 FR 64541 (October 23, 2015).

[615] See Exhibit 2–18. *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf*.

[616] If those generators were not receiving the tax credit, they otherwise would cease producing power during those periods and result in a lower overall capacity factor. As noted by EIA, ''Wind plants can offer negative prices because of the revenue stream that results from the federal production tax credit, which generates tax benefits whenever the wind plant is producing electricity, and payments from state renewable portfolio or financial incentive programs. These alternative revenue streams make it possible for wind generators to offer their wind power into the wholesale electricity market at prices lower than other generators, and even at negative prices.'' *https://www.eia.gov/todayinenergy/detail.php?id=16831*.

[617] A 12-year amortization period is consistent with the period of time during which the IRC section 45Q tax credit can be claimed.

[618] See the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional details.

period.[619] Considering that a significant number of sources can cost reasonably install CCS even assuming a 7-year amortization period, the EPA concludes that sources operating in 2039 should be subject to a CCS BSER,[620] and for this reason, is finalizing the date of January 1, 2039 as the dividing line between the medium-term and long-term subcategories. Moreover, the EPA underscores that given the strong economic incentives of the IRC section 45Q tax credit, sources that install CCS will have strong economic incentives to operate at high capacity for the full 12 years that the tax credit is available.

As discussed in the RTC section 2.16, the EPA has also examined the reasonableness of the costs of this rule in additional ways: considering the total annual costs of the rule as compared to past CAA rules for the electricity sector and as compared to the industry's annual revenues and annual capital expenditures, and considering the effects of this rule on electricity prices. Taking all of these into consideration, in addition to the cost metrics just discussed, the EPA concludes that, in general, the costs of CCS are reasonable for sources operating after January 1, 2039.

(A) Capture Costs

The EPA developed an independent engineering cost assessment for CCS retrofits, with support from Sargent and Lundy.[621] The EPA cost analysis assumes installation of one CO_2 capture plant for each coal-fired EGU, and that sources without SO_2 controls (FGD) or NO_X controls (specifically, selective catalytic reduction—SCR; or selective non-catalytic reduction—SNCR) add a wet FGD and/or SCR.[622]

(B) CO_2 Transport and Sequestration Costs

To calculate the costs of CCS for coal-fired steam generating units for purposes of determining BSER as well as for EPA modeling, the EPA relied on transportation and storage costs consistent with the cost of transporting and storing CO_2 from each power plant to the nearest saline reservoir.[623] For a power plant composed of multiple coal-fired EGUs, the EPA's cost analysis assumes installation and operation of a single, common CO_2 pipeline.

The EPA notes that NETL has also developed costs for transport and storage. NETL's "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies" provides an estimation of transport costs based on the CO_2 Transport Cost Model.[624] The CO_2 Transport Cost Model estimates costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operations and maintenance costs.[625]

NETL's Quality Guidelines also provide an estimate of sequestration costs. These costs reflect the cost of site screening and evaluation, permitting and construction costs, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection. Permitting and construction costs also reflect the regulatory requirements of the UIC Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations. NETL calculates these sequestration costs on the basis of generic plant locations in the Midwest, Texas, North Dakota, and Montana, as described in the NETL energy system studies that utilize the coal found in Illinois, East Texas, Williston, and Powder River basins.[626]

There are two primary cost drivers for a CO_2 sequestration project: the rate of injection of the CO_2 into the reservoir and the areal extent of the CO_2 plume in the reservoir. The rate of injection depends, in part, on the thickness of the reservoir and its permeability. Thick, permeable reservoirs provide for better injection and fewer injection wells. The areal extent of the CO_2 plume depends on the sequestration capacity of the reservoir. Thick, porous reservoirs with a good sequestration coefficient will present a small areal extent for the CO_2 plume and have a smaller monitoring footprint, resulting in lower monitoring costs. NETL's Quality Guidelines model costs for a given cumulative sequestration potential.[627]

In addition, provisions in the IIJA and IRA are expected to significantly increase the CO_2 pipeline infrastructure and development of sequestration sites, which, in turn, are expected to result in further cost reductions for the application of CCS at new combined cycle EGUs. The IIJA establishes a new Carbon Dioxide Transportation Infrastructure Finance and Innovation program to provide direct loans, loan guarantees, and grants to CO_2 infrastructure projects, such as pipelines, rail transport, ships and barges.[628] The IIJA also establishes a new Regional Direct Air Capture Hubs program that includes funds to support four large-scale, regional direct air capture hubs and more broadly support projects that could be developed into a regional or inter-regional network to facilitate sequestration or utilization.[629] DOE is additionally implementing IIJA section 40305 (Carbon Storage Validation and Testing) through its CarbonSAFE initiative, which aims to further develop geographically widespread, commercial-scale, safe sequestration.[630] The IRA increases and

[619] As indicated in section 4.7.5 of the final TSD, *Greenhouse Gas Mitigation Measures for Steam Generating Units,* 24 percent of all coal-fired steam generating units in the long-term subcategory would have CCS costs below both $18.50/MWh and $98/ton of CO_2 with a 7-year amortization period (Table 11), and that amount increases to 40 percent for those coal-fired units that, in light of their age and efficiency, are most likely to operate in the long term (and thus be subject to the CCS-based standards of performance) (Table 12). In addition, of the 9 units in the NEEDS data base that have announced plans to retire in 2039, and that therefore would have a 7-year amortization period if they installed CCS by January 1, 2032, 6 would have costs below both $18.50/MWh and $98/ton of CO_2.

[620] The EPA determines the BSER based on considering information on the statutory factors, including cost, on a source category or subcategory basis. However, there may be particular sources for which, based on source-specific considerations, the cost of CCS is fundamentally different from the costs the EPA considered in making its BSER determination. If such a fundamental difference makes it unreasonable for a particular source to achieve the degree of emission limitation associated with implementing CCS with 90 percent capture, a state may provide a less stringent standard of performance (and/or longer compliance schedule, if applicable) for that source pursuant to the RULOF provisions. See section X.C.2 of this preamble for further discussion.

[621] Detailed cost information, assessment of technology options, and demonstration of cost reasonableness can be found in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[622] Whether an FGD and SCR or controls with lower costs are necessary for flue gas pretreatment prior to the CO_2 capture process will in practice depend on the flue gas conditions of the source.

[623] For additional details on CO_2 transport and storage costs, see the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[624] Grant, T., *et al.* (2019). "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies." National Energy Technology Laboratory. *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[625] Grant, T., *et al.* "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies." National Energy Technology Laboratory. 2019. *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[626] National Energy Technology Laboratory (NETL). (2017). "FE/NETL CO_2 Saline Storage Cost Model (2017)," U.S. Department of Energy, DOE/NETL–2018–1871. *https://netl.doe.gov/energy-analysis/details?id=2403.*

[627] Details on CO_2 transportation and sequestration costs can be found in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[628] Department of Energy. "Biden-Harris Administration Announces $2 Billion from Bipartisan Infrastructure Law to Finance Carbon Dioxide Transportation Infrastructure." (2022). *https://www.energy.gov/articles/biden-harris-administration-announces-2-billion-bipartisan-infrastructure-law-finance.*

[629] Department of Energy. "Regional Direct Air Capture Hubs." (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[630] For more information, see the NETL announcement. *https://www.netl.doe.gov/node/12405.*

extends the IRC section 45Q tax credit, discussed next.

(C) IRC Section 45Q Tax Credit

In determining the cost of CCS, the EPA is taking into account the tax credit provided under IRC section 45Q, as revised by the IRA. The tax credit is available at $85/metric ton ($77/ton) and offsets a significant portion of the capture, transport, and sequestration costs noted above.

Several other aspects of the tax credit should be noted. A tax credit offsets tax liability dollar for dollar up to the amount of the taxpayer's tax liability. Any credits in excess of the taxpayer's liability are eligible to be carried back (3 years in the case of IRC section 45Q) and then carried forward up to 20 years.[631] As noted above, the IRA also enabled additional methods to monetize tax credits in the event the taxpayer does not have sufficient tax liability, such as through credit transfer.

The EPA has determined that it is likely that EGUs installing CCS will meet the 45Q prevailing wage and apprenticeship requirements. First, the requirements provide a significant economic incentive, increasing the value of the 45Q credit by five times over the base value of the credit available if the prevailing wage and apprenticeship requirements are not met. This provides a significant incentive to meet the requirements. Second, the increased cost of meeting the requirements is likely significantly less than the increase in credit value. A recent EPRI assessment found meeting the requirements for other types of power generation projects resulted in significant savings across projects,[632] and other studies indicate prevailing wage laws and requirements for construction projects in general do not significantly affect overall construction costs.[633] The EPA expects a similar dynamic for 45Q projects. Third, the use of registered apprenticeship programs for training new employees is generally well-established in the electric power generation sector, and apprenticeship programs are widely available to generate additional trained workers in this field.[634] The overall U.S. apprentice market has more than doubled between 2014 and 2023, growing at an average annual rate of more than 7 percent.[635] Additional programs support the skilled construction trade workforce required for CCS implementation and maintenance.[636]

As discussed in section V.C.2.c of this preamble, CAA section 111(a)(1) is clear that the cost that the Administrator must take into account in determining the BSER is the cost of the controls to the source. It is reasonable to take the tax credit into account because it reduces the cost of the controls to the source, which has a significant effect on the actual cost of installing and operating CCS. In addition, all sources that install CCS to meet the requirements of these final actions are eligible for the tax credit. The legislative history of the IRA makes clear that Congress was well aware that the EPA may promulgate rulemaking under CAA section 111 based on CCS and the utility of the tax credit in reducing the costs of CCUS (*i.e.,* CCS). Rep. Frank Pallone, the chair of the House Energy & Commerce Committee, included a statement in the Congressional Record when the House adopted the IRA in which he explained: ''The tax credit[ ] for CCUS . . . included in this Act may also figure into CAA Section 111 GHG regulations for new and existing industrial sources[.] . . . Congress anticipates that EPA may consider CCUS . . . as [a] candidate[ ] for BSER for electric generating plants . . . . Further, Congress anticipates that EPA may consider the impact of the CCUS . . . tax credit[ ] in lowering the costs of [that] measure[ ].'' 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone).

In the 2015 NSPS, in which the EPA determined partial CCS to be the BSER for GHGs from new coal-fired steam generating EGUs, the EPA recognized that the IRC section 45Q tax credit or other tax incentives could factor into the cost of the controls to the sources. Specifically, the EPA calculated the cost of partial CCS on the basis of cost calculations from NETL, which included ''a range of assumptions including the projected capital costs, the cost of financing the project, the fixed and variable O&M costs, the projected fuel costs, and incorporation of any incentives such as tax credits or favorable financing that may be available to the project developer.'' 80 FR 64570 (October 23, 2015).[637]

Similarly, in the 2015 NSPS, the EPA also recognized that revenues from utilizing captured CO_2 for EOR would reduce the cost of CCS to the sources, although the EPA did not account for potential EOR revenues for purposes of determining the BSER. *Id.* At 64563–64. In other rules, the EPA has considered revenues from sale of the by-products of emission controls to affect the costs of the emission controls. For example, in the 2016 Oil and Gas Methane Rule, the EPA determined that certain control requirements would reduce natural gas leaks and therefore result in the collection of recovered natural gas that could be sold; and the EPA further determined that revenues from the sale of the recovered natural gas reduces the cost of controls. See 81 FR 35824 (June 3, 2016). The EPA made the same determination in the 2024 Oil and Gas Methane Rule. See 89 FR 16820, 16865 (May 7, 2024). In a 2011 action concerning a regional haze SIP, the EPA recognized that a NO_X control would alter the chemical composition of fly ash that the source had previously sold, so that it could no longer be sold; and as a result, the EPA further determined that the cost of the NO_X control should include the foregone revenues from the fly ash sales. 76 FR 58570, 58603 (September 21, 2011). In the 2016 emission guidelines for landfill gas from municipal solid waste landfills, the EPA reduced the costs of controls by accounting for revenue from the sale of electricity produced from the landfill gas collected through the controls. 81 FR 59276, 19679 (August 29, 2016).

The amount of the IRC section 45Q tax credit that the EPA is taking into account is $85/metric ton for CO_2 that is captured and geologically stored. This amount is available to the affected source as long as it meets the prevailing wage and apprenticeship requirements of IRC section 45Q(h)(3)–(4). The legislative history to the IRA specifically stated that when the EPA considers CCS as the BSER for GHG emissions from industrial sources in CAA section 111 rulemaking, the EPA should determine the cost of CCS by assuming that the sources would meet those prevailing wage and apprenticeship requirements. 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone). If prevailing wage and apprenticeship requirements are not met, the value of the IRC section 45Q tax credit falls to $17/metric ton. The substantially higher credit available provides a considerable incentive to meeting the prevailing wage and apprenticeship requirements.

[631] IRC section 39.

[632] *https://www.epri.com/research/products/000000003002027328.*

[633] *https://journals.sagepub.com/doi/abs/10.1177/0160449X18766398.*

[634] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits.*

[635] *https://www.apprenticeship.gov/data-and-statistics.*

[636] *https://www.apprenticeship.gov/partner-finder.*

[637] In fact, because of limits on the availability of the IRC section 45Q tax credit at the time of the 2015 NSPS, the EPA did not factor it into the cost calculation for partial CCS. 80 FR 64558–64 (October 23, 2015).

Therefore, the EPA assumes that investors maximize the value of the IRC section 45Q tax credit at $85/metric ton by meeting those requirements.

(D) Comparison to Other Costs of Controls and Other Measures of Cost Reasonableness

In assessing cost reasonableness for the BSER determination for this rule, the EPA looks at a range of cost information. As discussed in Chapter 2 of the RTC, the EPA considered the total annual costs of the rule as compared to past CAA rules for the electricity sector and as compared to the industry's annual revenues and annual capital expenditures, and considered the effects of this rule on electricity prices.

For each of the BSER determinations, the EPA also considers cost metrics that it has historically considered in assessing costs to compare the costs of GHG control measures to control costs that the EPA has previously determined to be reasonable. This includes comparison to the costs of controls at EGUs for other air pollutants, such as SO_2 and NO_X, and costs of controls for GHGs in other industries. Based on these costs, the EPA has developed two metrics for assessing the cost reasonableness of controls: the increase in cost of electricity due to controls, measured in $/MWh, and the control costs of removing a ton of pollutant, measured in $/ton CO_2e. The costs presented in this section of the preamble are in 2019 dollars.[638]

In different rulemakings, the EPA has required many coal-fired steam generating units to install and operate flue gas desulfurization (FGD) equipment—that is, wet or dry scrubbers—to reduce their SO_2 emissions or SCR to reduce their NO_X emissions. The EPA compares these control costs across technologies—steam generating units and combustion turbines—because these costs are indicative of what is reasonable for the power sector in general. The facts that the EPA required these controls in prior rules, and that many EGUs subsequently installed and operated these controls, provide evidence that these costs are reasonable, and as a result, the cost of these controls provides a benchmark to assess the reasonableness of the costs of the controls in this preamble. In the 2011 CSAPR (76 FR 48208; August 8, 2011), the EPA estimated the annualized costs to install and operate wet FGD retrofits on existing coal-fired steam generating units. Using those same cost equations and assumptions (*i.e.*, a 63 percent annual capacity factor—the average value in 2011) for retrofitting wet FGD on a representative 700 to 300 MW coal-fired steam generating unit results in annualized costs of $14.80 to $18.50/MWh of generation, respectively.[639] In the Good Neighbor Plan for the 2015 Ozone NAAQS (2023 GNP), 88 FR 36654 (June 5, 2023), the EPA estimated the annualized costs to install and operate SCR retrofits on existing coal-fired steam generating units. Using those same cost equations and assumptions (including a 56 percent annual capacity factor—a representative value in that rulemaking) to retrofit SCR on a representative 700 to 300 MW coal-fired steam generating unit results in annualized costs of $10.60 to $11.80/MWh of generation, respectively.[640]

The EPA also compares costs to the costs for GHG controls in rulemakings for other industries. In the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category, the EPA found the costs of reducing methane emissions of $2,447/ton to be reasonable (80 FR 56627; September 18, 2015).[641] Converted to a ton of CO_2e reduced basis, those costs are expressed as $98/ton of CO_2e reduced.[642]

The EPA does not consider either of these metrics, $18.50/MWh and $98/ton of CO_2e, to be bright line standards that distinguish between levels of control costs that are reasonable and levels that are unreasonable. But they do usefully indicate that control costs that are generally consistent with those levels of control costs should be considered reasonable. The EPA has required controls with comparable costs in prior rules for the electric power industry and the industry has successfully complied with those rules by installing and operating the applicable controls. In the case of the $/ton metric, the EPA has required other industries—specifically, the oil and gas industry—to reduce their climate pollution at this level of cost-effectiveness. In this rulemaking, the costs of the controls that the EPA identifies as the BSER generally match up well against both of these $/MWh and $/ton metrics for the affected subcategories of sources. And looking broadly at the range of cost information and these cost metrics, the EPA concludes that the costs of these rules are reasonable.

(E) Comparison to Costs for CCS in Prior Rulemakings

In the CPP and ACE Rule, the EPA determined that CCS did not qualify as the BSER due to cost considerations. Two key developments have led the EPA to reevaluate this conclusion: the costs of CCS technology have fallen and the extension and increase in the IRC section 45Q tax credit, as included in the IRA, in effect provide a significant stream of revenue for sequestered CO_2 emissions. The CPP and ACE Rule relied on a 2015 NETL report estimating the cost of CCS. NETL has issued updated reports to incorporate the latest information available, most recently in 2022, which show significant cost reductions. The 2015 report estimated incremental levelized cost of CCS at a new pulverized coal facility relative to a new facility without CCS at $74/MWh (2022$),[643] while the 2022 report estimated incremental levelized cost at $44/MWh (2022$).[644] Additionally, the IRA increased the IRC section 45Q tax credit from $50/metric ton to $85/metric ton (and, in the case of EOR or certain industrial uses, from $35/metric ton to $60/metric ton), assuming prevailing wage and apprenticeship conditions are met. The IRA also enhanced the realized value of the tax credit through the elective pay (informally known as direct pay) and transferability monetization options described in section IV.E.1. The combination of lower costs and higher tax credits significantly improves the cost reasonableness of CCS for purposes

[638] The EPA used the NETL Baseline Report costs directly for the combustion turbine model plant BSER analysis. Even though these costs are in 2018 dollars, the adjustment to 2019 dollars (1.018 using the U.S. GDP Implicit Price Deflator) is well within the uncertainty range of the report and the minor adjustment would not impact the EPA's BSER determination.

[639] For additional details, see *https://www.epa.gov/power-sector-modeling/documentation-integrated-planning-model-ipm-base-case-v410.*

[640] For additional details, see *https://www.epa.gov/system/files/documents/2023-01/Updated%20Summer%202021%20Reference%20Case%20Incremental%20Documentation%20for%20the%202015%20Ozone%20NAAQS%20Actions_0.pdf.*

[641] The EPA finalized the 2016 NSPS GHGs for the Crude Oil and Natural Gas source category at 81 FR 35824 (June 3, 2016). The EPA included cost information in the proposed rulemaking, at 80 FR 56627 (September 18, 2015).

[642] Based on the 100-year global warming potential for methane of 25 used in the GHGRP (40 CFR 98 Subpart A, table A–1).

[643] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 3 (July 2015). *Note:* The EPA adjusted reported costs to reflect $2022. *https://www.netl.doe.gov/projects/files/CostandPerformanceBaselinefor FossilEnergyPlantsVolume1aBit CoalPCandNaturalGastoElectRev3_070615.pdf.*

[644] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022). *Note:* The EPA adjusted reported costs to reflect $2022. *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineFor FossilEnergyPlantsVolume1Bituminous CoalAndNaturalGasToElectricity_101422.pdf.*

of determining whether it qualifies as the BSER.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

The EPA considered non-GHG emissions impacts, the water use impacts, the transport and sequestration of captured CO_2, and energy requirements resulting from CCS for steam generating units. As discussed below, where the EPA has found potential for localized adverse consequences related to non-air quality health and environmental impacts or energy requirements, the EPA also finds that protections are in place to mitigate those risks. Because the non-air quality health and environmental impacts are closely related to the energy requirements, we discuss the latter first.

(A) Energy Requirements

For a steam generating unit with 90 percent amine-based CO_2 capture, parasitic/auxiliary energy demand increases and the net power output decreases. In particular, the solvent regeneration process requires heat in the form of steam and CO_2 compression requires a large amount of electricity. Heat and power for the CO_2 capture equipment can be provided either by using the steam and electricity produced by the steam generating unit or by an auxiliary cogeneration unit. However, any auxiliary source of heat and power is part of the ''designated facility,'' along with the steam generating unit. The standards of performance apply to the designated facility. Thus, any CO_2 emissions from the connected auxiliary equipment need to be captured or they will increase the facility's emission rate.

Using integrated heat and power can reduce the capacity (*i.e.*, the amount of electricity that a unit can distribute to the grid) of an approximately 474 MW-net (501 MW-gross) coal-fired steam generating unit without CCS to approximately 425 MW-net with CCS and contributes to a reduction in net efficiency of 23 percent.[645] For retrofits of CCS on existing sources, the ductwork for flue gas and piping for heat integration to overcome potential spatial constraints are a component of efficiency reduction. The EPA notes that slightly greater efficiency reductions than in the 2016 NETL retrofit report are assumed for the BSER cost analyses, as detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units*, available in the docket. Despite decreases in efficiency, IRC section 45Q tax credit provides an incentive for increased generation with full operation of CCS because the amount of revenue from the tax credit is based on the amount of captured and sequestered CO_2 emissions and not the amount of electricity generated. In this final action, the Agency considers the energy penalty to not be unreasonable and to be relatively minor compared to the benefits in GHG reduction of CCS.

(B) Non-GHG Emissions

As a part of considering the non-air quality health and environmental impacts of CCS, the EPA considered the potential non-GHG emission impacts of CO_2 capture. The EPA recognizes that amine-based CO_2 capture can, under some circumstances, result in the increase in emission of certain co-pollutants at a coal-fired steam generating unit. However, there are protections in place that can mitigate these impacts. For example, as discussed below, CCS retrofit projects with co-pollutant increases may be subject to preconstruction permitting under the New Source Review (NSR) program, which could require the source to adopt emission limitations based on applicable NSR requirements. Sources obtaining major NSR permits would be required to either apply Lowest Achievable Emission Rate (LAER) and fully offset any anticipated increases in criteria pollutant emissions (for their nonattainment pollutants) or apply Best Available Control Technology (BACT) and demonstrate that its emissions of criteria pollutants will not cause or contribute to a violation of applicable National Ambient Air Quality Standards (for their attainment pollutants).[646] The EPA expects facility owners, states, permitting authorities, and other responsible parties will use these protections to address co-pollutant impacts in situations where individual units use CCS to comply with these emission guidelines.

The EPA also expects that the meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders, including community members who might be adversely impacted by non-GHG pollutants, will have an opportunity to raise this concern with states and permitting authorities. Additionally, state permitting authorities are, in general, required to provide notice and an opportunity for public comment on construction projects that require NSR permits. This provides additional opportunities for affected stakeholders to engage in that process, and it is the EPA's expectation that the responsible authorities will consider these concerns and take full advantage of existing protections. Moreover, the EPA through its regional offices is committed to thoroughly review draft NSR permits associated with CO_2 capture projects and provide comments as necessary to state permitting authorities to address any concerns or questions with regard to the draft permit's consideration and treatment of non-GHG pollutants.

In the following discussion, the EPA describes the potential emissions of non-GHG pollutants resulting from installation and operation of CO_2 capture plants, the protections in place such as the controls and processes for mitigating those emissions, as well as regulations and permitting that may require review and implementation of those controls. The EPA first discusses these issues in relation to criteria air pollutants and precursor pollutants (SO_2, NO_X, and PM), and subsequently provides details regarding hazardous air pollutants (HAPs) and volatile organic compounds (VOCs).

Operation of an amine-based CO_2 capture plant on a coal-fired steam generating unit can impact the emission of criteria pollutants from the facility, including SO_2 and PM, as well as precursor pollutants, like NO_X. Sources installing CCS may operate more due to the incentives provided by the IRC section 45Q tax credit, and increased utilization would—all else being equal—result in increases in SO_2, PM, and NO_X. However, certain impacts are mitigated by the flue gas conditioning required by the CO_2 capture process and by other control equipment that the units already have or may need to install to meet other CAA requirements. Substantial flue gas conditioning, particularly to remove SO_2 and PM, is critical to limiting solvent degradation and maintaining reliable operation of the capture plant. To achieve the necessary limits on SO_2 levels in the flue gas for the capture process, steam generating units will need to add an FGD scrubber, if they do not already have one, and will usually need an additional polishing column (*i.e.*, quencher), thereby further reducing the emission of SO_2. A wet FGD column and a polishing column will also reduce the emission rate of PM. Additional improvements in PM removal may also be necessary to reduce the fouling of

[645] DOE/NETL–2016/1796. ''Eliminating the Derate of Carbon Capture Retrofits.'' May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=d335ce79-84ee-4a0b-a27b-c1a64edbb866.*

[646] Section XI.A of this preamble provides additional information on the NSR program and how it relates to the NSPS and emission guidelines.

other components (*e.g.*, heat exchangers) of the capture process, including upgrades to existing PM controls or, where appropriate, the inclusion of various wash stages to limit fly ash carry-over to the CO_2 removal system. Although PM emissions from the steam generating unit may be reduced, PM emissions may occur from cooling towers for those sources using wet cooling for the capture process. For some sources, a WESP may be necessary to limit the amount of aerosols in the flue gas prior to the CO_2 capture process. Reducing the amount of aerosols to the CO_2 absorber will also reduce emissions of the solvent out of the top of the absorber. Controls to limit emission of aerosols installed at the outlet of the absorber could be considered, but could lead to higher pressure drops. Thus, emission increases of SO_2 and PM would be reduced through flue gas conditioning and other system requirements of the CO_2 capture process, and NSR permitting would serve as an added backstop to review remaining SO_2 and PM increases for mitigation.

NO_X emissions can cause solvent degradation and nitrosamine formation, depending on the chemical structure of the solvent. Limits on NO_X levels of the flue gas required to avoid solvent degradation and nitrosamine formation in the CO_2 scrubber vary. For most units, the requisite limits on NO_X levels to assure that the CO_2 capture process functions properly may be met by the existing NO_X combustion controls. Other units may need to install SCR to achieve the required NOx level. Most existing coal-fired steam generating units either already have SCR or will be covered by final Federal Implementation Plan (FIP) requirements regulating interstate transport of NO_X (as ozone precursors) from EGUs. See 88 FR 36654 (June 5, 2023).[647] For units not otherwise required to have SCR, an increase in utilization from a CO_2 capture retrofit could result in increased NO_X emissions at the source that, depending on the quantity of the emissions increase, may trigger major NSR permitting requirements. Under this scenario, the permitting authority may determine that the NSR permit requires the installation of SCR for those units, based on applying the control technology requirements of major NSR. Alternatively, a state could, as part of its state plan, develop enforceable conditions for a source expected to trigger major NSR that would effectively limit the unit's ability to increase its emissions in amounts that would trigger major NSR. Under this scenario, with no major NSR requirements applying due to the limit on the emissions increase, the permitting authority may conclude for the minor NSR permit that installation of SCR is not required for the units and the source is to minimize its NO_X emission increases using other techniques. Finally, a source with some lesser increase in NO_X emissions may not trigger major NSR to begin with and, as with the previous scenario, the permitting authority would determine the NO_X control requirements pursuant to its minor NSR program requirements.

Recognizing that potential emission increases of SO_2, PM, and NO_X from operating a CO_2 capture process are an area of concern for stakeholders, the EPA plans to review and update as needed its guidance on NSR permitting, specifically with respect to BACT determinations for GHG emissions and consideration of co-pollutant increases from sources installing CCS. In its analysis to support this final action, the EPA accounted for controlling these co-pollutant increases by assuming that coal-fired units that install CCS would be required to install SCR and/or FGD if they do not already have those controls installed. The costs of these controls are included in the total program compliance cost estimates through IPM modeling, as well as in the BSER cost calculations.

An amine-based CO_2 capture plant can also impact emissions of HAP and VOC (as an ozone precursor) from the coal-fired steam generating unit. Degradation of the solvent can produce HAP, and organic HAP and amine solvent emissions from the absorber would contribute to VOC emissions out of the top of the CO_2 absorber. A conventional multistage water or acid wash and mist eliminator (demister) at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.*, nitrosamine) emissions.[648] [649] The DOE's Carbon Management Pathway report notes that monitoring and emission controls for such degradation products are currently part of standard operating procedures for amine-based CO_2 capture systems.[650] Depending on the solvent properties, different amounts of aldehydes including acetaldehyde and formaldehyde may form through oxidative processes, contributing to total HAP and VOC emissions. While a water wash or acid wash can be effective at limiting emission of amines, a separate system of controls would be required to reduce aldehyde emissions; however, the low temperature and likely high water vapor content of the gas emitted out of absorber may limit the applicability of catalytic or thermal oxidation. Other controls (*e.g.*, electrochemical, ultraviolet) common to water treatment could be considered to reduce the loading of copollutants in the water wash section, although their efficacy is still in development and it is possible that partial treatment could result in the formation of additional degradation products. Apart from these potential controls, any increase in VOC emissions from a CCS retrofit project would be mitigated through NSR permitting. As such VOC increases are not expected to be large enough to trigger major NSR requirements, they would likely be reviewed and addressed under a state's minor NSR program.

There is one nitrosamine that is a listed HAP regulated under CAA section 112. Carbon capture systems that are themselves a major source of HAP should evaluate the applicability of CAA section 112(g) and conduct a case-by-case MACT analysis if required, to establish MACT for any listed HAP, including listed nitrosamines, formaldehyde, and acetaldehyde. Because of the differences in the formation and effectiveness of controls, such a case-by-case MACT analysis should evaluate the performance of controls for nitrosamines and aldehydes separately, as formaldehyde or acetaldehyde may not be a suitable surrogate for amine and nitrosamine emissions. However, measurement of nitrosamine emissions may be challenging when the concentration is low (*e.g.*, less than 1 part per billion, dry basis).

HAP emissions from the CO_2 capture plant will depend on the flue gas

[647] As of September 21, 2023, the Good Neighbor Plan "Group 3" ozone-season NO_X control program for power plants is being implemented in the following states: Illinois, Indiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and Wisconsin. Pursuant to court orders staying the Agency's FIP Disapproval action as to the following states, the EPA is not currently implementing the Good Neighbor Plan "Group 3" ozone-season NO_X control program for power plants in the following states: Alabama, Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and West Virginia.

[648] Sharma, S., Azzi, M., "A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies," *Fuel,* 121, 178 (2014).

[649] Mertens, J., *et al.,* "Understanding ethanolamine (MEA) and ammonia emissions from amine-based post combustion carbon capture: Lessons learned from field tests," *Int'l J. of GHG Control,* 13, 72 (2013).

[650] U.S. Department of Energy (DOE). Pathways to Commercial Liftoff: Carbon Management. *https://liftoff.energy.gov/wp-content/uploads/2023/04/20230424-Liftoff-Carbon-Management-vPUB_update.pdf.*

conditions, solvent, size of the source, and process design. The air permit application for Project Tundra [651] includes potential-to-emit (PTE) values for CAA section 112 listed HAP specific to the 530 MW-equivalent CO_2 capture plant, including emissions of 1.75 tons per year (TPY) of formaldehyde (CASRN 50–00–0), 32.9 TPY of acetaldehyde (CASRN 75–07–0), 0.54 TPY of acetamide (CASRN 60–35–5), 0.018 TPY of ethylenimine (CASRN 151–56–4), 0.044 TPY of N-nitrosodimethylamine (CASRN 62–75–9), and 0.018 TPY of N-nitrosomorpholine (CASRN 59–89–2). Additional PTE other species that are not CAA section 112 listed HAP were also included, including 0.022 TPY of N-nitrosodiethylamine (CASRN 55–18–5). PTE values for other CO_2 capture plants may differ. To comply with North Dakota Department of Environmental Quality (ND–DEQ) Air Toxics Policy, an air toxics assessment was included in the permit application. According to that assessment, the total maximum individual carcinogenic risk was 1.02E–6 (approximately 1-in-1 million, below the ND–DEQ threshold of 1E–5) primarily driven by N-nitrosodiethylamine and N-nitrosodimethylamine. The hazard index value was 0.022 (below the ND–DEQ threshold of 1), with formaldehyde being the primary driver. Results of air toxics risk assessments for other facilities would depend on the emissions from the facility, controls in place, stack height and flue gas conditions, local ambient conditions, and the relative location of the exposed population.

Emissions of amines and nitrosamines at Project Tundra are controlled by the water wash section of the absorber column. According to the permit to construct issued by ND–DEQ, limits for formaldehyde and acetaldehyde will be established based on testing after initial operation of the CO_2 capture plant. The permit does not include a mechanism for establishing limits for nitrosamine emissions, as they may be below the limit of detection (less than 1 part per billion, dry basis).

The EPA received several comments related to the potential for non-GHG emissions associated with CCS. Those comments and the EPA's responses are as follows.

Comment: Some commenters noted that there is a potential for increases in co-pollutants when operating amine-based CO_2 capture systems. One commenter requested that the EPA proactively regulate potential nitrosamine emissions.

Response: The EPA carefully considered these concerns as it finalized its determination of the BSERs for these rules. The EPA takes these concerns seriously, agrees that any impacts to local and downwind communities are important to consider and has done so as part of its analysis discussed at section XII.E. While the EPA acknowledges that, in some circumstances, there is potential for some non-GHG emissions to increase, there are several protections in place to help mitigate these impacts. The EPA believes that these protections, along with the meaningful engagement of potentially affected communities, can facilitate a responsible deployment of this technology that mitigates the risk of any adverse impacts.

There is one nitrosamine that is a listed HAP under CAA section 112 (N-Nitrosodimethylamine; CASRN 62–75–9). Other nitrosamines would have to be listed before the EPA could establish regulations limiting their emission. Furthermore, carbon capture systems are themselves not a listed source category of HAP, and the listing of a source category under CAA section 112 would first require some number of the sources to exist for the EPA to develop MACT standards. However, if a new CO_2 capture facility were to be permitted as a separate entity (rather than as part of the EGU) then it may be subject to case-by-case MACT under section 112(g), as detailed in the preceding section of this preamble.

Comment: Commenters noted that a source could attempt to permit CO_2 facilities as separate entities to avoid triggering NSR for the EGU.

Response: For the CO_2 capture plant to be permitted as a separate entity, the source would have to demonstrate to the state permitting authority that the EGU and CO_2 capture plant are not a single stationary source under the NSR program. In determining what constitutes a stationary source, the EPA's NSR regulations set forth criteria that are to be used when determining the scope of a ''stationary source.'' [652] These criteria require the aggregation of different pollutant-emitting activities if they (1) belong to the same industrial grouping as defined by SIC codes, (2) are located on contiguous or adjacent properties, and (3) are under common control.[653] In the case of an EGU and CO_2 capture plant that are collocated, to permit them as separate sources they should not be under common control or not be defined by the same industrial grouping.

The EPA would anticipate that, in most cases, the operation of the EGU and the CO_2 capture plant will intrinsically affect one another—typically steam, electricity, and the flue gas of the EGU will be provided to the CO_2 capture plant. Conditions of the flue gas will affect the operation of the CO_2 capture plant, including its emissions, and the steam and electrical load will affect the operation of the EGU. Moreover, the emissions from the EGU will be routed through the CO_2 capture system and emitted out of the top of the CO_2 absorber. Even if the EGU and CO_2 capture plant are owned by separate entities, the CO_2 capture plant is likely to be on or directly adjacent to land owned by the owners of the EGU and contractual obligations are likely to exist between the two owners. While each of these individual factors may not ultimately determine the outcome of whether two nominally-separate facilities should be treated as a single stationary source for permitting purposes, the EPA expects that in most cases an EGU and its collocated CO_2 capture plant would meet each of the aforementioned NSR regulatory criteria necessary to make such a determination. Thus, the EPA generally would not expect an EGU and its CO_2 capture plant to be permitted as separate stationary sources.

(C) Water Use

Water consumption at the plant increases when applying carbon capture, due to solvent water makeup and cooling demand. Water consumption can increase by 36 percent on a gross basis.[654] A separate cooling water system dedicated to a CO_2 capture plant may be necessary. However, the amount of water consumption depends on the design of the cooling system. For example, the cooling system cited in the CCS feasibility study for SaskPower's Shand Power station would rely entirely on water condensed from the flue gas and thus would not require any increase in external water consumption—all while achieving higher capture rates at lower cost than Boundary Dam Unit 3.[655] Regions with limited water supply

[651] DCC East PTC Application. *https://ceris.deq.nd.gov/ext/nsite/map/results/detail/-8992368000928857057/documents.*

[652] 40 CFR 51.165(a)(1)(i) and (ii); 40 CFR 51.166(b)(5) and (6).

[653] The EPA has issued guidance to clarify these regulatory criteria of stationary source determination. See *https://www.epa.gov/nsr/single-source-determination.*

[654] DOE/NETL–2016/1796. ''Eliminating the Derate of Carbon Capture Retrofits.'' May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9.*

[655] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://*

Continued

may therefore rely on dry or hybrid cooling systems. Therefore, the EPA considers the water use requirements to be manageable and does not expect this consideration to preclude coal-fired power plants generally from being able to install and operate CCS.

(D) CO_2 Capture Plant Siting

With respect to siting considerations, CO_2 capture systems have a sizeable physical footprint and a consequent land-use requirement. One commenter cited their analysis showing that, for a subset of coal-fired sources greater than 300 MW, 98 percent (154 GW of the existing fleet) have adjacent land available within 1 mile of the facility, and 83 percent have adjacent land available within 100 meters of the facility. Furthermore, the cited analysis did not include land available onsite, and it is therefore possible there is even greater land availability for siting capture equipment. Qualitatively, some commenters claimed there is limited land available for siting CO_2 capture plants adjacent to coal-fired steam generating units. However, those commenters provided no data or analysis to support their assertion. The EPA has reviewed the analysis provided by the first commenter, and the approach, methods, and assumptions are logical. Further, the EPA has reviewed the available information, including the location of coal-fired steam generating units and visual inspection of the associated maps and plots. Although in some cases longer duct runs may be required, this would not preclude coal-fired power plants generally from being able to install and operate CCS. Therefore, the EPA has concluded that siting and land-use requirements for CO_2 capture are not unreasonable.

(E) Transport and Geologic Sequestration

As noted in section VII.C.1.a.i(C) of this preamble, PHMSA oversight of supercritical CO_2 pipeline safety protects against environmental release during transport. The vast majority of CO_2 pipelines have been operating safely for more than 60 years. PHMSA reported a total of 102 CO_2 pipeline incidents between 2003 and 2022, with one injury (requiring in-patient hospitalization) and zero fatalities.[656] In the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines with zero incidents involving fatalities.[657] PHMSA initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of supercritical CO_2 pipelines. Furthermore, UIC Class VI and Class II regulations under the SDWA, in tandem with GHGRP subpart RR and subpart VV requirements, ensure the protection of USDWs and the security of geologic sequestration. The EPA believes these protections constitute an effective framework for addressing potential health and environmental concerns related to CO_2 transportation and sequestration, and the EPA has taken this regulatory framework into consideration in determining that CCS represents the BSER for long-term steam EGUs.

(F) Impacts on the Energy Sector

Additionally, the EPA considered the impacts on the power sector, on a nationwide and long-term basis, of determining CCS to be the BSER for long-term coal-fired steam generating units. In this final action, the EPA considers that designating CCS as the BSER for these units would have limited and non-adverse impacts on the long-term structure of the power sector or on the reliability of the power sector. Absent the requirements defined in this action, the EPA projects that 11 GW of coal-fired steam generating units would apply CCS by 2035 and an additional 30 GW of coal-fired steam generating units, without controls, would remain in operation in 2040. Designating CCS to be the BSER for existing long-term coal-fired steam generating units may result in more of the coal-fired steam generating unit capacity applying CCS. The time available before the compliance deadline of January 1, 2032, provides for adequate resource planning, including accounting for the downtime necessary to install the CO_2 capture equipment at long-term coal-fired steam generating units. For the 12-year duration that eligible EGUs earn the IRC section 45Q tax credit, long-term coal-fired steam generating units are anticipated to run at or near base load conditions in order to maximize the amount of tax credit earned through IRC section 45Q. Total generation from coal-fired steam generating units in the medium-term subcategory would gradually decrease over an extended period of time through 2039, subject to the commitments those units have chosen to adopt. Additionally, for the long-term units applying CCS, the EPA has determined that the increase in the annualized cost of generation is reasonable. Therefore, the EPA concludes that these elements of BSER can be implemented while maintaining a reliable electric grid. A broader discussion of reliability impacts of these final rules is available in section XII.F of this preamble.

iv. Extent of Reductions in CO_2 Emissions

CCS is an extremely effective technology for reducing CO_2 emissions. As of 2021, coal-fired power plants are the largest stationary source of GHG emissions by sector. Furthermore, emission rates (lb CO_2/MWh-gross) from coal-fired sources are almost twice those of natural gas-fired combined cycle units, and sources operating in the long-term have the more substantial emissions potential. CCS can be applied to coal-fired steam generating units at the source to reduce the mass of CO_2 emissions by 90 percent or more. Increased steam and power demand have a small impact on the reduction in emission rate (*i.e.*, lb CO_2/MWh-gross) that occurs with 90 percent capture. According to the 2016 NETL Retrofit report, 90 percent capture will result in emission rates that are 88.4 percent lower on a lb/MWh-gross basis and 87.1 percent lower on a lb/MWh-net basis compared to units without capture.[658] After capture, CO_2 can be transported and securely sequestered.[659] Although steam generating units with CO_2 capture will have an incentive to operate at higher utilization because the cost to install the CCS system is largely fixed and the IRC section 45Q tax credit increases based on the amount of CO_2 captured and sequestered, any increase in utilization will be far outweighed by the substantial reductions in emission rate.

v. Promotion of the Development and Implementation of Technology

The EPA considered the potential impact on technology advancement of designating CCS as the BSER for long-term coal-fired steam generating units, and in this final rule, the EPA considers

ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.

[656] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety, and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[657] Congressional Research Service. 2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June 3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[658] DOE/NETL–2016/1796. "Eliminating the Derate of Carbon Capture Retrofits." May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9.*

[659] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

that designating CCS as the BSER will provide for meaningful advancement of CCS technology. As indicated above, the EPA's IPM modeling indicates that 11 GW of coal-fired power plants install CCS and generate 76 terawatt-hours (TWh) per year in the base case, and that another 8 GW of plants install CCS and generate another 57 TWh per year in the policy case. In this manner, this rule advances CCS technology more widely throughout the coal-fired power sector. As discussed in section VIII.F.4.c.iv(G) of this preamble, this rule advances CCS technology for new combined cycle base load combustion turbines, as well. It is also likely that this rule supports advances in the technology in other industries.

vi. Comparison With 2015 NSPS For Newly Constructed Coal-Fired EGUs

In the 2015 NSPS, the EPA determined that the BSER for newly constructed coal-fired EGUs was based on CCS with 16 to 23 percent capture, based on the type of coal combusted, and consequently, the EPA promulgated standards of performance of 1,400 lb CO_2/MWh-g. 80 FR 64512 (table 1), 64513 (October 23, 2015). The EPA made those determinations based on the costs of CCS at the time of that rulemaking. In general, those costs were significantly higher than at present, due to recent technology cost declines as well as related policies, including the IRC section 45Q tax credit for CCS, which were not available at that time for purposes of consideration during the development of the NSPS. *Id.* at 64562 (table 8). Based on of these higher costs, the EPA determined that 16–23 percent capture qualified as the BSER, rather than a significantly higher percentage of capture. Given the substantial differences in the cost of CCS during the time of the 2015 NSPS and the present time, the capture percentage of the 2015 NSPS necessarily differed from the capture percentage in this final action, and, by the same token, the associated degree of emission limitation and resulting standards of performance necessarily differ as well. If the EPA had strong evidence to indicate that new coal-fired EGUs would be built, it would propose to revise the 2015 NSPS to align the BSER and emissions standards to reflect the new information regarding the costs of CCS. Because there is no evidence to suggest that there are any firm plans to build new coal-fired EGUs in the future, however, it is not at present a good use of the EPA's limited resources to propose to update the new source standard to align with the existing source standard finalized today. While the EPA is not revising the new source standard for new coal-fired EGUs in this action, the EPA is retaining the ability to propose review in the future.

vii. Requirement That Source Must Transfer CO_2 to an Entity That Reports Under the Greenhouse Gas Reporting Program

The final rule requires that EGUs that capture CO_2 in order to meet the applicable emission standard report in accordance with the GHGRP requirements of 40 CFR part 98, including subpart PP. GHGRP subpart RR and subpart VV requirements provide the monitoring and reporting mechanisms to quantify CO_2 storage and to identify, quantify, and address potential leakage. Under existing GHGRP regulations, sequestration wells permitted as Class VI under the UIC program are required to report under subpart RR. Facilities with UIC Class II wells that inject CO_2 to enhance the recovery of oil or natural gas can opt-in to reporting under subpart RR by submitting and receiving approval for a monitoring, reporting, and verification (MRV) plan. Subpart VV applies to facilities that conduct enhanced recovery using ISO 27916 to quantify geologic storage unless they have opted to report under subpart RR. For this rule, if injection occurs on site, the EGU must report data accordingly under 40 CFR part 98 subpart RR or subpart VV. If the CO_2 is injected off site, the EGU must transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR or subpart VV. They may also transfer the captured CO_2 to a facility that has received an innovative technology waiver from the EPA.

b. Options Not Determined To Be the BSER for Long-Term Coal-Fired Steam Generating Units

In this section, we explain why CCS at 90 percent capture best balances the BSER factors and therefore why the EPA has determined it to be the best of the possible options for the BSER.

i. Partial Capture CCS

Partial capture for CCS was not determined to be BSER because the emission reductions are lower and the costs would, in general, be higher. As discussed in section IV.B of this preamble, individual coal-fired power plants are by far the highest-emitting plants in the nation, and the coal-fired power plant sector is higher-emitting than any other stationary source sector. CCS at 90 percent capture removes very high absolute amounts of emissions. Partial capture CCS would fail to capture large quantities of emissions. With respect to costs, designs for 90 percent capture in general take greater advantage of economies of scale. Eligibility for the IRC section 45Q tax credit for existing EGUs requires design capture rates equivalent to 75 percent of a baseline emission rate by mass. Even assuming partial capture rates meet that definition, lower capture rates would receive fewer returns from the IRC section 45Q tax credit (since these are tied to the amount of carbon sequestered, and all else being equal lower capture rates would result in lower amounts of sequestered carbon) and costs would thereby be higher.

ii. Natural Gas Co-Firing

(A) Reasons Why Not Selected as BSER

As discussed in section VII.C.2, the EPA is determining 40 percent natural gas co-firing to qualify as the BSER for the medium-term subcategory of coal-fired steam generating units. This subcategory consists of units that will permanently cease operation by January 1, 2039. In making this BSER determination, the EPA analyzed the ability of all existing coal-fired units—not only medium-term units—to install and operate 40 percent co-firing. As a result, all of the determinations concerning the criteria for BSER that the EPA made for 40 percent co-firing apply to all existing coal-fired units, including the units in the long-term subcategory. For example, 40 percent co-firing is adequately demonstrated for the long-term subcategory, and has reasonable energy requirements and reasonable non-air quality environmental impacts. It would also be of reasonable cost for the long-term subcategory. Although the capital expenditure for natural gas co-firing is lower than CCS, the variable costs are higher. As a result, the total costs of natural gas co-firing, in general, are higher on a $/ton basis and not substantially lower on a $/MWh basis, than for CCS. Were co-firing the BSER for long-term units, the cost that industry would bear might then be considered similar to the cost for CCS. In addition, the GHG Mitigation Measures TSD shows that all coal-fired units would be able to achieve the requisite infrastructure build-out and obtain sufficient quantities of natural gas to comply with standards of performance based on 40 percent co-firing by January 1, 2030.

The EPA is not selecting 40 percent natural gas co-firing as the BSER for the long-term subcategory, however, because it requires substantially less emission reductions at the unit-level than 90 percent capture CCS. Natural gas co-firing at 40 percent of the heat input to the steam generating unit achieves 16 percent reductions in emission rate at the stack, while CCS achieves an 88.4 percent reduction in emission rate. As discussed in section IV.B of this preamble, individual coal-fired power plants are by far the highest-emitting plants in the nation, and the coal-fired power plant sector is higher-emitting than any other stationary source sector. Because the unit-level emission reductions achievable by CCS are substantially greater, and because CCS is of reasonable cost and matches up well against the other BSER criteria, the EPA did not determine natural gas co-firing to be BSER for the long-term subcategory although, under other circumstances, it could be. Determining BSER requires the EPA to select the ''best'' of the systems of emission reduction that are adequately demonstrated, as described in section V.C.2; in this case, there are two systems of emission reduction that match up well against the BSER criteria, but based on weighing the criteria together, and in light of the substantially greater unit-level emission reductions from CCS, the EPA has determined that CCS is a better system of emission reduction than co-firing for the long-term subcategory.

The EPA notes that if a state demonstrates that a long-term coal-fired steam generating unit cannot install and operate CCS and cannot otherwise reasonably achieve the degree of emission limitation that the EPA has determined based on CCS, following the process the EPA has specified in its applicable regulations for consideration of RULOF, the state would evaluate natural gas co-firing as a potential basis for establishing a less stringent standard of performance, as detailed in section X.C.2 of this document.

iii. Heat Rate Improvements

Heat rate improvements were not considered to be BSER for long-term steam generating units because the achievable reductions are very low and may result in a rebound effect whereby total emissions from the source increase, as detailed in section VII.D.4.a of this preamble.

Comment: One commenter requested that HRI be considered as BSER in addition to CCS, so that long-term sources would be required to achieve reductions in emission rate consistent with performing HRI and adding CCS with 90 percent capture to the source.

Response: As described in section VII.D.4.a, the reductions from HRI are very low and many sources have already made HRI, so that additional reductions are not available. It is possible that a source installing CO_2 capture will make efficiency improvements as a matter of best practices. For example, Boundary Dam Unit 3 made upgrades to the existing steam generating unit when CCS was installed, including installing a new steam turbine.[660] However, the reductions from efficiency improvements would not be additive to the reductions from CCS because of the impact of the CO_2 capture plant on the efficiency of source due to the required steam and electricity load of the capture plant.

c. Conclusion

Coal-fired EGUs remain the largest stationary source of dangerous CO_2 emissions. The EPA is finalizing CCS at a capture rate of 90 percent as the BSER for long-term coal-fired steam generating units because this system satisfies the criteria for BSER as summarized here. CCS at a capture rate of 90 percent as the BSER for long-term coal-fired steam generating units is adequately demonstrated, as indicated by the facts that it has been operated at scale, is widely applicable to these sources, and that there are vast sequestration opportunities across the continental U.S. Additionally, accounting for recent technology cost declines as well as policies including the tax credit under IRC section 45Q, the costs for CCS are reasonable. Moreover, any adverse non-air quality health and environmental impacts and energy requirements of CCS, including impacts on the power sector on a nationwide basis, are limited and can be effectively avoided or mitigated. In contrast, co-firing 40 percent natural gas would achieve far fewer emission reductions without improving the cost reasonableness of the control strategy.

These considerations provide the basis for finalizing CCS as the best of the systems of emission reduction for long-term coal-fired power plants. In addition, determining CCS as the BSER promotes advancements in control technology for CO_2, which is a relevant consideration when establishing BSER under section 111 of the CAA.

i. Adequately Demonstrated

CCS with 90 percent capture is adequately demonstrated based on the information in section VII.C.1.a.i of this preamble. Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s[661] and has been used in a variety of industrial applications for decades. Thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[662] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with EOR.[663] There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under construction or in advanced stages of development.[664] This broad application of CCS demonstrates the successful operation of all three components of CCS, operating both independently and simultaneously. Various CO_2 capture methods are used in industrial applications and are tailored to the flue gas conditions of a particular industry (see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for details). Of those capture technologies, amine solvent-based capture has been demonstrated for removal of CO_2 from the post-combustion flue gas of fossil fuel-fired EGUs.

Since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant (Trona, California).[665] Amine solvent capture has been further demonstrated at coal-fired power plants including AES's Warrior Run and Shady Point. And since 2014, CCS has been applied at the commercial scale at Boundary Dam Unit 3, a 110 MW lignite coal-fired steam generating unit in Saskatchewan, Canada.

Impending increases in Canadian regulatory CO_2 emission requirements have prompted optimization of Boundary Dam Unit 3 so that the facility now captures 83 percent of its total CO_2 emissions. Moreover, from the flue gas

[660] IEAGHG Report 2015–06. Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station. August 2015. *https://ieaghg.org/publications/technical-reports/reports-list/9-technical-reports/935-2015-06-integrated-ccs-project-at-saskpower-s-boundary-dam-power-station.*

[661] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[662] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[663] US EPA. GHGRP. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[664] Carbon Capture and Storage in the United States. CBO. December 13, 2023. *https://www.cbo.gov/publication/59345.*

[665] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

treated, Boundary Dam Unit 3 consistently captured 90 percent or more of the CO_2 over a 3-year period. The adequate demonstration of CCS is further corroborated by the EPAct05-assisted 240MW-equivalent Petra Nova CCS project at the coal-fired W.A. Parish Unit 8, which achieved over 90 percent capture from the treated flue gas during a 3-year period. Additionally, the technical improvements put in practice at Boundary Dam Unit 3 and Petra Nova can be put in place on new capture facilities during initial construction. This includes redundancies and isolations for key equipment, and spray systems to limit fly ash carryover. Projects that have announced plans to install CO_2 capture directly include these improvements in their design and employ new solvents achieving higher capture rates that are commercially available from technology providers. As a result, these projects target capture efficiencies of at least 95 percent, well above the BSER finalized here.

Precedent, building upon the statutory text and context, has established that the EPA may make a finding of adequate demonstration by drawing upon existing data from individual commercial-scale sources, including testing at these sources,[666] and that the agency may make projections based on existing data to establish a more stringent standard than has been regularly shown,[667] in particular in cases when the agency can specifically identify technological improvements that can be expected to achieve the standard in question.[668] Further, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different, related, source.[669] Following this legal standard, the available data regarding performance and testing at Boundary Dam, a commercial-scale plant, is enough, by itself, to support the EPA's adequate demonstration finding for a 90 percent standard. In addition to this, however, in the 9 years since Boundary Dam began operating, operators and the EPA have developed a clear understanding of specific technological improvements which, if implemented, the EPA can reasonably expect to lead to a 90 percent capture rate on a regular and ongoing basis. The D.C. Circuit has established that this information is more than enough to establish that a 90 percent standard is achievable.[670] And per *Lignite Energy Council*, the findings from Boundary Dam can be extrapolated to other, similarly operating power plants, including natural gas plants.[671]

Transport of CO_2 and geological storage of CO_2 have also been adequately demonstrated, as detailed in VII.C.1.a.i(B)(7) and VII.C.1.a.i(D)(2). CO_2 has been transported through pipelines for over 60 years, and in the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines. CO_2 pipeline controls and PHMSA standards ensure that captured CO_2 will be securely conveyed to a sequestration site. Due to the proximity of sources to storage, it would be feasible for most sources to build smaller and shorter source-to-sink laterals, rather than rely on a trunkline network buildout. In addition to pipelines, CO_2 can also be transported via vessel, highway, or rail. Geological storage is proven and broadly available, and of the coal-fired steam generating units with planned operation during or after 2030, 77 percent are within 40 miles of the boundary of a saline reservoir.

The EPA also considered the timelines, materials, and workforce necessary for installing CCS, and determined they are sufficient.

ii. Cost

Process improvements have resulted in a decrease in the projected costs to install CCS on existing coal-fired steam generating units. Additionally, the IRC section 45Q tax credit provides $85 per metric ton ($77 per ton) of CO_2. It is reasonable to account for the IRC section 45Q tax credit because the costs that should be accounted for are the costs to the source. For the fleet of coal-fired steam generating units with planned operation during or after 2033, and assuming a 12-year amortization period and 80 percent annual capacity factor and including source specific transport and storage costs, the average total costs of CCS are −$5/ton of CO_2 reduced and −$4/MWh. And even for shorter amortization periods, the $/MWh costs are comparable to or less than the costs for other controls ($10.60–$18.50/MWh) for a substantial number of sources. Notably, the EPA's IPM model projects that even without this final rule—that is, in the base case, without any CAA section 111 requirements—some units would deploy CCS. Similarly, the IPM model projects that even if this rule determined 40 percent co-firing to be the BSER for long-term coal, instead of CCS, some additional units would deploy CCS. Therefore, the costs of CCS with 90 percent capture are reasonable.

iii. Non-Air Quality Health and Environmental Impacts and Energy Requirements

The CO_2 capture plant requires substantial pre-treatment of the flue gas to remove SO_2 and fly ash (PM) while other controls and process designs are necessary to minimize solvent degradation and solvent loss. Although CCS has the potential to result in some increases in non-GHG emissions, a robust regulatory framework, generally implemented at the state level, is in place to mitigate other non-GHG emissions from the CO_2 capture plant. For transport, pipeline safety is regulated by PHMSA, while UIC Class VI regulations under the SDWA, in tandem with GHGRP subpart RR requirements, ensure the protection of USDWs and the security of geologic sequestration. Therefore, the potential non-air quality health and environmental impacts do not militate against designating CCS as the BSER for long-term steam EGUs. The EPA also considered energy requirements. While the CO_2 capture plant requires steam and electricity to operate, the incentives provided by the IRC section 45Q tax credit will likely result in increased total generation from the source. Therefore, the energy requirements are not unreasonable, and there would be limited, non-adverse impacts on the broader energy sector.

2. Medium-Term Coal-Fired Steam Generating Units

The EPA is finalizing its conclusion that 40 percent natural gas co-firing on a heat input basis is the BSER for medium-term coal-fired steam generating units. Co-firing 40 percent natural gas, on an annual average heat input basis, results in a 16 percent reduction in CO_2 emission rate. The technology has been adequately demonstrated, can be implemented at reasonable cost, does not have significant adverse non-air quality health and environmental impacts or energy requirements, including impacts on the energy sector, and achieves meaningful reductions in CO_2 emissions. Co-firing also advances useful control technology, which provides additional, although not essential, support for treating it as the BSER.

[666] *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775 (D.C. Cir. 1976).

[667] *See id.*

[668] *See Sierra Club* v. *Costle,* 657 F.2d 298 (1981).

[669] *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[670] *See, e.g., Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (1981).

[671] 198 F.3d 930 (D.C. Cir. 1999).

a. Rationale for the Medium-Term Coal-Fired Steam Generating Unit Subcategory

For the development of the emission guidelines, the EPA first considered CCS as the BSER for existing coal-fired steam generating units. CCS generally achieves significant emission reductions at reasonable cost. Typically, in setting the BSER, the EPA assumes that regulated units will continue to operate indefinitely. However, that assumption is not appropriate for all coal-fired steam generating units. 62 percent of existing coal-fired steam generating units greater than 25 MW have already announced that they will retire or convert from coal to gas by 2039.[672] CCS is capital cost-intensive, entailing a certain period to amortize the capital costs. Therefore, the EPA evaluated the costs of CCS for different amortization periods, as detailed in section VII.C.1.a.ii of the preamble, and determined that CCS was cost reasonable, on average, for sources operating more than 7 years after the compliance date of January 1, 2032. Accordingly, units that cease operating before January 1, 2039, will generally have less time to amortize the capital costs, and the costs for those sources would be higher and thereby less comparable to those the EPA has previously determined to be reasonable. Considering this, and the other factors evaluated in determining BSER, the EPA is not finalizing CCS as BSER for units demonstrating that they plan to permanently cease operation prior to January 1, 2039.

Instead, the EPA is subcategorizing these units into the medium-term subcategory and finalizing a BSER based on 40 percent natural gas co-firing on a heat input basis for these units. Co-firing natural gas at 40 percent has significantly lower capital costs than CCS and can be implemented by January 1, 2030. For sources that expect to continue in operation until January 1, 2039, and that therefore have a 9-year amortization period, the costs of 40 percent co-firing are $73/ton of CO_2 reduced or $13/MWh of generation, which supports their reasonableness because they are comparable to or less than the costs detailed in section VII.C.1.a.ii(D) of this preamble for other controls on EGUs ($10.60 to $18.50/MWh) and for GHGs for the Crude Oil and Natural Gas source category in the 2016 NSPS of $98/ton of CO_{2e} reduced (80 FR 56627; September 18, 2015). Co-firing is also cost-reasonable for sources permanently ceasing operations sooner, and that therefore have a shorter amortization period. As discussed in section VII.B.2 of this preamble, with a two-year amortization period, many units can co-fire with meaningful amounts of natural gas at reasonable cost. Of course, even more can co-fire at reasonable costs with amortization periods longer than two years. For example, the EPA has determined that 33 percent of sources with an amortization period of at least three years have costs for 40 percent co-firing below both of the $/ton and $/MWh metrics, and 68 percent of those sources have costs for 20 percent co-firing below both of those metrics. Therefore, recognizing that operating horizon affects the cost reasonableness of controls, the EPA is finalizing a separate subcategory for coal-fired steam generating units operating in the medium-term—those demonstrating that they plan to permanently cease operation after December 31, 2031, and before January 1, 2039—with 40 percent natural gas co-firing as the BSER.

i. Legal Basis for Establishing the Medium-Term Subcategory

As noted in section V.C.1 of this preamble, the EPA has broad authority under CAA section 111(d) to identify subcategories. As also noted in section V.C.1, the EPA's authority to "distinguish among classes, types, and sizes within categories," as provided under CAA section 111(b)(2) and as we interpret CAA section 111(d) to provide as well, generally allows the Agency to place types of sources into subcategories when they have characteristics that are relevant to the controls that the EPA may determine to be the BSER for those sources. One element of the BSER is cost reasonableness. See CAA section 111(d)(1) (requiring the EPA, in setting the BSER, to "tak[e] into account the cost of achieving such reduction"). As noted in section V, the EPA's longstanding regulations under CAA section 111(d) explicitly recognize that subcategorizing may be appropriate for sources based on the "costs of control."[673] Subcategorizing on the basis of operating horizon is consistent with a key characteristic of the coal-fired power industry that is relevant for determining the cost reasonableness of control requirements: A large percentage of the sources in the industry have already announced, and more are expected to announce, dates for ceasing operation, and the fact that many coal-fired steam generating units intend to cease operation in the near term affects what controls are "best" for different subcategories.[674] At the outset, installation of emission control technology takes time, sometimes several years. Whether the costs of control are reasonable depends in part on the period of time over which the affected sources can amortize those costs. Sources that have shorter operating horizons will have less time to amortize capital costs. Thus, the annualized cost of controls may thereby be less comparable to the costs the EPA has previously determined to be reasonable.[675]

In addition, subcategorizing by length of period of continued operation is similar to two other bases for subcategorization on which the EPA has relied in prior rules, each of which implicates the cost reasonableness of controls: The first is load level, noted in section V.C.1. of this preamble. For

[672] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[673] 40 CFR 60.22(b)(5), 60.22a(b)(5).

[674] The EPA recognizes that section 111(d) provides that in applying standards of performance, a state may take into account, among other factors, the remaining useful life of a facility. The EPA believes that provision is intended to address exceptional circumstances at particular facilities, while the EPA has the responsibility to determine how to address the source category as a whole. See 88 FR 80480, 80511 (November 17, 2023) ("Under CAA 111, EPA must provide BSER and degree of emission limitation determinations that are, to the extent reasonably practicable, applicable to all designated facilities in the source category. In many cases, this requires the EPA to create subcategories of designated facilities, each of which has a BSER and degree of emission limitation tailored to its circumstances. . . . However, as Congress recognized, this may not be possible in every instance because, for example, it is not be feasible [sic] for the Agency to know and consider the idiosyncrasies of every designated facility or because the circumstances of individual facilities change after the EPA determined the BSER.") (internal citations omitted). That a state may take into account the remaining useful life of an individual source, however, does not bar the EPA from considering operating horizon as a factor in determining whether subcategorization is appropriate. As discussed, the authority to subcategorize is encompassed within the EPA's authority to identify the BSER. Here, where many units share similar characteristics and have announced intended shorter operating horizons, it is permissible for the EPA to take operating horizon into account in determining the BSER for this subcategory of sources. States may continue to take RULOF factors into account for particular units where the information relevant to those units is fundamentally different than the information the EPA took into account in determining the degree of emission limitation achievable through application of the BSER. Should a court conclude that the EPA does not have the authority to create a subcategory based on the date at which units intend to cease operation, then the EPA believes it would be reasonable for states to consider co-firing as an alternative to CCS as an option for these units through the states' authority to consider, among other factors, remaining useful life.

[675] Steam Electric Reconsideration Rule, 85 FR 64650, 64679 (October 13, 2020) (distinguishes between EGUs retiring before 2028 and EGUs remaining in operation after that time).

example, in the 2015 NSPS, the EPA divided new natural gas-fired combustion turbines into the subcategories of base load and non-base load. 80 FR 64602 (table 15) (October 23, 2015). The EPA did so because the control technologies that were ''best''—including consideration of feasibility and cost reasonableness—depended on how much the unit operated. The load level, which relates to the amount of product produced on a yearly or other basis, bears similarity to a limit on a period of continued operation, which concerns the amount of time remaining to produce the product. In both cases, certain technologies may not be cost-reasonable because of the capacity to produce product—*i.e.*, the costs are spread over less product produced. Subcategorization on this basis is also supported by how utilities manage their assets over the long term, and was widely supported by industry commenters.

The second basis for subcategorization on which EPA has previously relied is fuel type, as also noted in section V.C.1 of this preamble. The 2015 NSPS provides an example of this type of subcategorization as well. There, the EPA divided new combustion turbines into subcategories on the basis of type of fuel combusted. *Id.* Subcategorizing on the basis of the type of fuel combusted may be appropriate when different controls have different costs, depending on the type of fuel, so that the cost reasonableness of the control depends on the type of fuel. In that way, it is similar to subcategorizing by operating horizon because in both cases, the subcategory is based upon the cost reasonableness of controls. Subcategorizing by operating horizon is also tantamount to the length of time over which the source will continue to combust the fuel. Subcategorizing on this basis may be appropriate when different controls for a particular fuel have different costs, depending on the length of time when the fuel will continue to be combusted, so that the cost reasonableness of controls depends on that timeframe. Some prior EPA rules for coal-fired sources have made explicit the link between length of time for continued operation and type of fuel combusted by codifying federally enforceable retirement dates as the dates by which the source must ''cease burning coal.'' [676]

[676] See 79 FR 5031, 5192 (January 30, 2014) (explaining that ''[t]he construction permit issued by Wyoming requires Naughton Unit 3 to *cease burning coal* by December 31, 2017, and to be retrofitted to natural gas as its fuel source by June 30, 2018'' (emphasis added)).

As noted above, creating a subcategory on the basis of operating horizon does not preclude a state from considering RULOF in applying a standard of performance to a particular source. The EPA's authority to set BSER for a source category (including subcategories) and a state's authority to invoke RULOF for individual sources within a category or subcategory are distinct. The EPA's statutory obligation is to determine a generally applicable BSER for a source category, and where that source category encompasses different classes, types, or sizes of sources, to set generally applicable BSERs for subcategories accounting for those differences. By contrast, states' authority to invoke RULOF is premised on the state's ability to take into account information relevant to individual units that is fundamentally different than the information the EPA took into account in determining BSER generally. As noted, the EPA may subcategorize on the basis of cost of controls, and operating horizon may factor into the cost of controls. Moreover, through section 111(d)(1), Congress also required the EPA to develop regulations that permit states to consider ''among other factors, the remaining useful life'' of a particular existing source. The EPA has interpreted these other factors to include costs or technical feasibility specific to a particular source, even though these are factors the EPA itself considers in setting the BSER. In other words, the factors the EPA may consider in setting the BSER and the factors the states may consider in applying standards of performance are not distinct. As noted above, the EPA is finalizing these subcategories in response to requests by power sector representatives that this rule accommodate the fact that there is a class of sources that plan to voluntarily cease operations in the near term. Although the EPA has designed the subcategories to accommodate those requests, a particular source may still present source-specific considerations—whether related to its remaining useful life or other factors—that the state may consider relevant for the application of that particular source's standard of performance, and that the state should address as described in section X.C.2 of this preamble.

ii. Comments Received on Existing Coal-Fired Subcategories

Comment: The EPA received several comments on the proposed subcategories for coal-fired steam generating units. Many commenters, including industry commenters, supported these subcategories. Some commenters opposed these proposed subcategories. They argued that the subcategories were designed to force coal-fired power plants to retire.

Response: We disagree with comments suggesting that the subcategories for existing coal-fired steam EGUs that the EPA has finalized in this rule were designed to force retirements. The subcategories were not designed for that purpose, and the commenters do not explain their allegations to the contrary. The subcategories were designed, at industry's request,[677] to ensure that subcategories of units that can feasibly and cost-reasonably employ emissions reduction technologies—and only those subcategories of units that can do so—are required to reduce their emissions commensurate with those technologies. As explained above, in determining the BSER, the EPA generally assumes that a source will operate indefinitely, and calculates expected control costs on that basis. Under that assumption, the BSER for existing fossil-fuel fired EGUs is CCS. Nevertheless, the EPA recognizes that many fossil-fuel fired EGUs have already announced plans to cease operation. In recognition of this unique, distinguishing factor, the EPA determined whether a different BSER would be appropriate for fossil fuel-fired EGUs that do not intend to operate over the long term, and concluded, for the reasons stated above, that natural gas co-firing was appropriate for these sources that intended to cease operation before 2039. This subcategory is not intended to force retirements, and the EPA is not directing any state or any unit as to the choice of when to cease operation. Rather, the EPA has created this subcategory to accommodate these sources' intended operation plans. In fact, a number of industry commenters specifically requested and supported subcategories based on retirement dates in recognition of the reality that many operators are choosing to retire these units and that whether or not a control technology is feasible and cost-reasonable depends upon how long a unit intends to operate.

Specifically, as noted in section VII.B of this preamble, in this final action, the

[677] As described in the proposal, 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. 88 FR 33245 (May 23, 2023).

medium-term subcategory includes a date for permanently ceasing operation, which applies to coal-fired plants demonstrating that they plan to permanently cease operating after December 31, 2031, and before January 1, 2039. The EPA is retaining this subcategory because 55 percent of existing coal-fired steam generating units greater than 25 MW have already announced that they will retire or convert from coal to gas by January 1, 2039.[678] Accordingly, the costs of CCS—the high capital costs of which require a lengthy amortization period from its January 1, 2032, implementation date—are higher than the traditional metric for cost reasonableness for these sources. As discussed in section VII.C.2 of this preamble, the BSER for these sources is co-firing 40 percent natural gas. This is because co-firing, which has an implementation date of January 1, 2030, has lower capital costs and is therefore cost-reasonable for sources continuing to operate on or after January 1, 2032. It is further noted that this subcategory is elective. Furthermore, states also have the authority to establish a less stringent standard through RULOF in the state plan process, as detailed in section X.C.2 of this preamble.

In sum, these emission guidelines do not require any coal-fired steam EGU to retire, nor are they intended to induce retirements. Rather, these emission guidelines simply set forth presumptive standards that are cost-reasonable and achievable for each subcategory of existing coal-fired steam EGUs. See section VII.E.1 of this preamble (responding to comments that this rule violates the major questions doctrine).

Comment: The EPA broadly solicited comment on the dates and values defining the proposed subcategories for coal-fired steam generating units. Regarding the proposed dates for the subcategories, one industry stakeholder commented that the ''EPA's proposed retirement dates for applicability of the various subcategories are appropriate and broadly consistent with system reliability needs.'' [679] More specifically, industry commenters requested that the cease-operation-by date for the imminent-term subcategory be changed from January 1, 2032, to January 1, 2033. Industry commenters also stated that the 20 percent utilization limit in the definition of the near-term subcategory was overly restrictive and inconsistent with the emissions stringency of either the proposed medium term or imminent term subcategory—commenters requested greater flexibility for the near-term subcategory. Other comments from NGOs and other groups suggested various other changes to the subcategory definitions. One commenter requested moving the cease-operation-by date for the medium-term subcategory up to January 1, 2038, while eliminating the imminent-term subcategory and extending the near-term subcategory to January 1, 2038.

Response: The EPA is not finalizing the proposed imminent-term or near-term subcategories. The EPA is finalizing an applicability exemption for sources demonstrating that they plan to permanently cease operation prior to January 1, 2032, as detailed in section VII.B of this preamble. The EPA is finalizing the cease operating by date of January 1, 2039, for medium-term coal-fired steam generating units. These dates are all based on costs of co-firing and CCS, driven by their amortization periods, as discussed in the preceding sections of this preamble.

b. Rationale for Natural Gas Co-Firing as the BSER for Medium-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA describes its rationale for natural gas co-firing as the final BSER for medium-term coal-fired steam generating units.

For a coal-fired steam generating unit, the substitution of natural gas for some of the coal, so that the unit fires a combination of coal and natural gas, is known as ''natural gas co-firing.'' The EPA is finalizing natural gas co-firing at a level of 40 percent of annual heat input as BSER for medium-term coal-fired steam generating units.

i. Adequately Demonstrated

The EPA is finalizing its determination that natural gas co-firing at the level of 40 percent of annual heat input is adequately demonstrated for coal-fired steam generating units. Many existing coal-fired steam generating units already use some amount of natural gas, and several have co-fired at relatively high levels at or above 40 percent of heat input in recent years.

(A) Boiler Modifications

Existing coal-fired steam generating units can be modified to co-fire natural gas in any desired proportion with coal, up to 100 percent natural gas. Generally, the modification of existing boilers to enable or increase natural gas firing typically involves the installation of new gas burners and related boiler modifications, including, for example, new fuel supply lines and modifications to existing air ducts. The introduction of natural gas as a fuel can reduce boiler efficiency slightly, due in large part to the relatively high hydrogen content of natural gas. However, since the reduction in coal can result in reduced auxiliary power demand, the overall impact on net heat rate can range from a 2 percent increase to a 2 percent decrease.

It is common practice for steam generating units to have the capability to burn multiple fuels onsite, and of the 565 coal-fired steam generating units operating at the end of 2021, 249 of them reported consuming natural gas as a fuel or startup source. Coal-fired steam generating units often use natural gas or oil as a startup fuel, to warm the units up before running them at full capacity with coal. While startup fuels are generally used at low levels (up to roughly 1 percent of capacity on an annual average basis), some coal-fired steam generating units have co-fired natural gas at considerably higher shares. Based on hourly reported CO_2 emission rates from the start of 2015 through the end of 2020, 29 coal-fired steam generating units co-fired with natural gas at rates at or above 60 percent of capacity on an hourly basis.[680] The capability of those units on an hourly basis is indicative of the extent of boiler burner modifications and sizing and capacity of natural gas pipelines to those units, and implies that those units are technically capable of co-firing at least 60 percent natural gas on a heat input basis on average over the course of an extended period (*e.g.*, a year). Additionally, during that same 2015 through 2020 period, 29 coal-fired steam generating units co-fired natural gas at over 40 percent on an annual heat input basis. Because of the number of units that have demonstrated co-firing above 40 percent of heat input, the EPA is finalizing that co-firing at 40 percent is adequately demonstrated. A more detailed discussion of the record of natural gas co-firing, including current trends, at coal-fired steam generating units is included in the final TSD, *GHG Mitigation Measures for Steam Generating Units*.

(B) Natural Gas Pipeline Development

In addition to any potential boiler modifications, the supply of natural gas is necessary to enable co-firing at existing coal-fired steam boilers. As

[678] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs*.

[679] See Document ID No. EPA–HQ–OAR–2023–0072–0772.

[680] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data website: *https://campd.epa.gov*.

discussed in the previous section, many plants already have at least some access to natural gas. In order to increase natural gas access beyond current levels, plants may find it necessary to construct natural gas supply pipelines.

The U.S. natural gas pipeline network consists of approximately 3 million miles of pipelines that connect natural gas production with consumers of natural gas. To increase natural gas consumption at a coal-fired boiler without sufficient existing natural gas access, it is necessary to connect the facility to the natural gas pipeline transmission network via the construction of a lateral pipeline. The cost of doing so is a function of the total necessary pipeline capacity (which is characterized by the length, size, and number of laterals) and the location of the plant relative to the existing pipeline transmission network. The EPA estimated the costs associated with developing new lateral pipeline capacity sufficient to meet 60 percent of the net summer capacity at each coal-fired steam generating unit that could be included in this subcategory. As discussed in the final TSD, *GHG Mitigation Measures for Steam Generating Units*, the EPA estimates that this lateral capacity would be sufficient to enable each unit to achieve 40 percent natural gas co-firing on an annual average basis.

The EPA considered the availability of the upstream natural gas pipeline capacity to satisfy the assumed co-firing demand implied by these new laterals. This analysis included pipeline development at all EGUs that could be included in this subcategory, including those without announced plans to cease operating before January 1, 2039. The EPA's assessment reviewed the reasonableness of each assumed new lateral by determining whether the peak gas capacity of that lateral could be satisfied without modification of the transmission pipeline systems to which it is assumed to be connected. This analysis found that most, if not all, existing pipeline systems are currently able to meet the peak needs implied by these new laterals in aggregate, assuming that each existing coal-fired unit in the analysis co-fired with natural gas at a level implied by these new laterals, or 60 percent of net summer generating capacity. While this is a reasonable assumption for the analysis to support this mitigation measure in the BSER context, it is also a conservative assumption that overstates the amount of natural gas co-firing expected under the final rule.[681]

Most of these individual laterals are less than 15 miles in length. The maximum aggregate amount of pipeline capacity, if all coal-fired steam capacity that could be included in the medium-term subcategory (*i.e.*, all capacity that has not announced that it plans to retire by 2032) implemented the final BSER by co-firing 40 percent natural gas, would be comparable to pipeline capacity constructed recently. The EPA estimates that this maximum total capacity would be nearly 14.7 billion cubic feet per day, which would require about 3,500 miles of pipeline costing roughly $11.5 billion. Over 2 years,[682] this maximum total incremental pipeline capacity would amount to less than 1,800 miles per year, with a total annual capacity of roughly 7.35 billion cubic feet per day. This represents an estimated annual investment of approximately $5.75 billion per year in capital expenditures, on average. By comparison, based on data collected by EIA, the total annual mileage of natural gas pipelines constructed over the 2017–2021 period ranged from approximately 1,000 to 2,500 miles per year, with a total annual capacity of 10 to 25 billion cubic feet per day. This represents an estimated annual investment of up to nearly $15 billion. The upper end of these historical annual values is much higher than the maximum annual values that could be expected under this final BSER measure—which, as noted above, represent a conservative estimate that significantly overstates the amount of co-firing that the EPA projects would occur under this final rule.

These conservatively high estimates of pipeline requirements also compare favorably to industry projections of future pipeline capacity additions. Based on a review of a 2018 industry report, titled ''North America Midstream Infrastructure through 2035: Significant Development Continues,'' investment in midstream infrastructure development is expected to range between $10 to $20 billion per year through 2035. Approximately $5 to $10 billion annually is expected to be invested in natural gas pipelines through 2035. This report also projects that an average of over 1,400 miles of new natural gas pipeline will be built through 2035, which is similar to the approximately 1,670 miles that were built on average from 2013 to 2017. These values are consistent with the average annual expenditure of $5.75 billion on less than 1,800 miles per year of new pipeline construction that would be necessary for the entire operational fleet of existing coal-fired steam generating units to co-fire with natural gas. The actual pipeline investment for this subcategory would be substantially lower.

(C) Compliance Date for Medium-Term Coal-Fired Steam Generating Units

The EPA is finalizing a compliance date for medium-term coal-fired steam generating units of January 1, 2030.

As in the timeline for CCS for the long term coal-fired steam generating units described in section VII.C.1.a.i(E), the EPA assumes here that feasibility work occurs during the state plan development period, and that all subsequent work occurs after the state plan is submitted and thereby effective at the state level. The EPA assumes 12 months of feasibility work for the natural gas pipeline lateral and 6 months of feasibility work for boiler modifications (both to occur over June 2024 to June 2025). As with the feasibility analysis for CCS, the feasibility analysis for co-firing will inform the state plan and therefore it is reasonable to assume units will perform it during the state planning window. Feasibility for the pipeline includes a right-of-way and routing analysis. Feasibility for the boiler modifications includes conceptual studies and design basis.

The timeline for the natural gas pipeline permitting and construction is based on a review of recently completed permitting approvals and construction.[683] The average time to complete permitting and approval is less than 1.5 years, and the average time to complete actual construction is less than 1 year. Of the 31 reviewed pipeline projects, the vast majority (27 projects) took less than a total of 3 years for permitting and construction, and none took more than 3.5 years. Therefore, it is reasonable to assume that permitting and construction would take no more than 3 years for most sources (June 2026 to June 2029), noting that permitting

[681] In practice, not all sources would necessarily be subject to a natural gas co-firing BSER in compliance. *E.g.*, some portion of that population of sources could install CCS, so the resulting amount of natural gas co-firing would be less.

[682] The average time for permitting for a natural gas pipeline lateral is 1.5 years, and many sources could be permitted faster (about 1 year) so that it is reasonable to assume that many sources could begin construction by June 2027. The average time for construction of an individual pipeline is about 1 year or less. Considering this, the EPA assumes construction of all of the natural gas pipeline laterals in the analysis occurs over a 2-year period (June 2027 through June 2029), and notes that in practice some of these projects could be constructed outside of this period.

[683] Documentation for the Lateral Cost Estimation (2024), ICF International. Available in Docket ID EPA–HQ–OAR–2023–0072.

and construction for many sources would be faster.

The timeline for boiler modifications based on the baseline duration co-firing conversion project schedule developed by Sargent and Lundy.[684] The EPA assumes that, with the exception of the feasibility studies discussed above, work on the boiler modifications begins after the state plan submission due date. The EPA also assumes permitting for the boiler modifications is required and takes 12 months (June 2026 to June 2027). In the schedule developed by Sargent and Lundy, commercial arrangements for the boiler modification take about 6 months (June 2026 to December 2026). Detailed engineering and procurement takes about 7 months (December 2026 to July 2027), and begins after commercial arrangements are complete. Site work takes 3 months (July 2027 to October 2027), followed by 4 months of construction (October 2027 to February 2028). Lastly, startup and testing takes about 2 months (June 2029 to August 2029), noting that the EPA assumes this occurs after the natural gas pipeline lateral is constructed. Considering the preceding information, the EPA has determined January 1, 2030 is the compliance date for medium-term coal-fired steam generating units.

ii. Costs

The capital costs associated with the addition of new gas burners and other necessary boiler modifications depend on the extent to which the current boiler is already able to co-fire with some natural gas and on the amount of gas co-firing desired. The EPA estimates that, on average, the total capital cost associated with modifying existing boilers to operate at up to 100 percent of heat input using natural gas is approximately $52/kW. These costs could be higher or lower, depending on the equipment that is already installed and the expected impact on heat rate or steam temperature.

While fixed O&M (FOM) costs can potentially decrease as a result of decreasing the amount of coal consumed, it is common for plants to maintain operation of one coal pulverizer at all times, which is necessary for maintaining several coal burners in continuous service. In this case, coal handling equipment would be required to operate continuously and therefore natural gas co-firing would have limited effect on reducing the coal-related FOM costs. Although, as noted, coal-related FOM costs have the potential to decrease, the EPA does not anticipate a significant increase in impact on FOM costs related to co-firing with natural gas.

In addition to capital and FOM cost impacts, any additional natural gas co-firing would result in incremental costs related to the differential in fuel cost, taking into consideration the difference in delivered coal and gas prices, as well as any potential impact on the overall net heat rate. The EPA's reference case projects that in 2030, the average delivered price of coal will be $1.56/MMBtu and the average delivered price of natural gas will be $2.95/MMBtu. Thus, assuming the same level of generation and no impact on heat rate, the additional fuel cost would be $1.39/MMBtu on average in 2030. The total additional fuel cost could increase or decrease depending on the potential impact on net heat rate. An increase in net heat rate, for example, would result in more fuel required to produce a given amount of generation and thus additional cost. In the final TSD, *GHG Mitigation Measures for Steam Generating Units,* the EPA's cost estimates assume a 1 percent average increase in net heat rate.

Finally, for plants without sufficient access to natural gas, it is also necessary to construct new natural gas pipelines (''laterals''). Pipeline costs are typically expressed in terms of dollars per inch of pipeline diameter per mile of pipeline distance (*i.e.*, dollars per inch-mile), reflecting the fact that costs increase with larger diameters and longer pipelines. On average, the cost for lateral development within the contiguous U.S. is approximately $280,000 per inch-mile (2019$), which can vary based on site-specific factors. The total pipeline cost for each coal-fired steam generating unit is a function of this cost, as well as a function of the necessary pipeline capacity and the location of the plant relative to the existing pipeline transmission network. The pipeline capacity required depends on the amount of co-firing desired as well as on the desired level of generation—a higher degree of co-firing while operating at full load would require more pipeline capacity than a lower degree of co-firing while operating at partial load. It is reasonable to assume that most plant owners would develop sufficient pipeline capacity to deliver the maximum amount of desired gas use in any moment, enabling higher levels of co-firing during periods of lower fuel price differentials. Once the necessary pipeline capacity is determined, the total lateral cost can be estimated by considering the location of each plant relative to the existing natural gas transmission pipelines as well as the available excess capacity of each of those existing pipelines.

The EPA determined the costs of 40 percent co-firing based on the fleet of coal-fired steam generating units that existed in 2021 and that do not have known plans to cease operations or convert to gas by 2032, and assuming that each of those units continues to operate at the same level as it operated over 2017–2021. The EPA assessed those costs against the cost reasonableness metrics, as described in section VII.C.1.a.ii(D) of this preamble (*i.e.*, emission control costs on EGUs of $10.60 to $18.50/MWh and the costs in the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category of $98/ton of CO_{2e} reduced (80 FR 56627; September 18, 2015)). On average, the EPA estimates that the weighted average cost of co-firing with 40 percent natural gas as the BSER on an annual average basis is approximately $73/ton CO_2 reduced, or $13/MWh. The costs here reflect an amortization period of 9 years. These estimates support a conclusion that co-firing is cost-reasonable for sources that continue to operate up until the January 1, 2039, threshold date for the subcategory. The EPA also evaluated the fleet average costs of natural gas co-firing for shorter amortization periods and has determined that the costs are consistent with the cost reasonableness metrics for the majority of sources that will operate past January 1, 2032, and therefore have an amortization period of at least 2 years and up to 9 years. These estimates and all underlying assumptions are explained in detail in the final TSD, *GHG Mitigation Measures for Steam Generating Units.* Based on this cost analysis, alongside the EPA's overall assessment of the costs of this rule, the EPA is finalizing that the costs of natural gas co-firing are reasonable for the medium-term coal-fired steam generating unit subcategory. If a particular source has costs of 40 percent co-firing that are fundamentally different from the cost reasonability metrics, the state may consider this fact under the RULOF provisions, as detailed in section X.C.2 of this preamble. The EPA previously estimated the cost of natural gas co-firing in the Clean Power Plan (CPP). 80 FR 64662 (October 23, 2015). The cost-estimates for co-firing presented in this section are lower than in the CPP, for several reasons. Since then, the expected difference between coal and gas prices has decreased significantly, from over $3/MMBtu to less than $1.50/MMBtu in this final rule. Additionally,

[684] Natural Gas Co-Firing Memo, Sargent & Lundy (2023). Available in Docket ID EPA–HQ–OAR–2023–0072.

a recent analysis performed by Sargent and Lundy for the EPA supports a considerably lower capital cost for modifying existing boilers to co-fire with natural gas. The EPA also recently conducted a highly detailed facility-level analysis of natural gas pipeline costs, the median value of which is slightly lower than the value used by the EPA previously to approximate the cost of co-firing at a representative unit.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Natural gas co-firing for steam generating units is not expected to have any significant adverse consequences related to non-air quality health and environmental impacts or energy requirements.

(A) Non-GHG Emissions

Non-GHG emissions are reduced when steam generating units co-fire with natural gas because less coal is combusted. SO_2, $PM_{2.5}$, acid gas, mercury and other hazardous air pollutant emissions that result from coal combustion are reduced proportionally to the amount of natural gas consumed, *i.e.*, under this final rule, by 40 percent. Natural gas combustion does produce NO_X emissions, but in lesser amounts than from coal-firing. However, the magnitude of this reduction is dependent on the combustion system modifications that are implemented to facilitate natural gas co-firing.

Sufficient regulations also exist related to natural gas pipelines and transport that assure natural gas can be safely transported with minimal risk of environmental release. PHMSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.6 million mile pipeline transportation system. Recently, PHMSA finalized a rule that will improve the safety and strengthen the environmental protection of more than 300,000 miles of onshore gas transmission pipelines.[685] PHMSA also recently promulgated a separate rule covering natural gas transmission,[686] as well as a rule that significantly expanded the scope of safety and reporting requirements for more than 400,000 miles of previously unregulated gas gathering lines.[687] FERC is responsible for the regulation of the siting, construction, and/or abandonment of interstate natural gas pipelines, gas storage facilities, and Liquified Natural Gas (LNG) terminals.

(B) Energy Requirements

The introduction of natural gas co-firing will cause steam boilers to be slightly less efficient due to the high hydrogen content of natural gas. Co-firing at levels between 20 percent and 100 percent can be expected to decrease boiler efficiency between 1 percent and 5 percent. However, despite the decrease in boiler efficiency, the overall net output efficiency of a steam generating unit that switches from coal- to natural gas-firing may change only slightly, in either a positive or negative direction. Since co-firing reduces coal consumption, the auxiliary power demand related to coal handling and emissions controls typically decreases as well. While a site-specific analysis would be required to determine the overall net impact of these countervailing factors, generally the effect of co-firing on net unit heat rate can vary within approximately plus or minus 2 percent.

The EPA previously determined in the ACE Rule (84 FR 32545; July 8, 2019) that ''co-firing natural gas in coal-fired utility boilers is not the best or most efficient use of natural gas and [. . .] can lead to less efficient operation of utility boilers.'' That determination was informed by the more limited supply of natural gas, and the larger amount of coal-fired EGU capacity and generation, in 2019. Since that determination, the expected supply of natural gas has expanded considerably, and the capacity and generation of the existing coal-fired fleet has decreased, reducing the total mass of natural gas that might be required for sources to implement this measure.

Furthermore, regarding the efficient operation of boilers, the ACE determination was based on the observation that ''co-firing can negatively impact a unit's heat rate (efficiency) due to the high hydrogen content of natural gas and the resulting production of water as a combustion by-product.'' That finding does not consider the fact that the effect of co-firing on net unit heat rate can vary within approximately plus or minus 2 percent, and therefore the net impact on overall utility boiler efficiency for each steam generating unit is uncertain.

For all of these reasons, the EPA is finalizing that natural gas co-firing at medium-term coal-fired steam generating units does not result in any significant adverse consequences related to energy requirements.

Additionally, the EPA considered longer term impacts on the energy sector, and the EPA is finalizing these impacts are reasonable. Designating natural gas co-firing as the BSER for medium-term coal-fired steam generating units would not have significant adverse impacts on the structure of the energy sector. Steam generating units that currently are coal-fired would be able to remain primarily coal-fired. The replacement of some coal with natural gas as fuel in these sources would not have significant adverse effects on the price of natural gas or the price of electricity.

iv. Extent of Reductions in CO_2 Emissions

One of the primary benefits of natural gas co-firing is emission reduction. CO_2 emissions are reduced by approximately 4 percent for every additional 10 percent of co-firing. When moving from 100 percent coal to 60 percent coal and 40 percent natural gas, CO_2 stack emissions are reduced by approximately 16 percent. Non-CO_2 emissions are reduced as well, as noted earlier in this preamble.

v. Technology Advancement

Natural gas co-firing is already well-established and widely used by coal-fired steam boiler generating units. As a result, this final rule is not likely to lead to technological advances or cost reductions in the components of natural gas co-firing, including modifications to boilers and pipeline construction. However, greater use of natural gas co-firing may lead to improvements in the efficiency of conducting natural gas co-firing and operating the associated equipment.

c. Options Not Determined To Be the BSER for Medium-Term Coal-Fired Steam Generating Units

i. CCS

As discussed earlier in this preamble, the compliance date for CCS is January 1, 2032. Accordingly, sources in the medium-term subcategory—which have elected to commit to permanently cease operations prior to 2039—would have less than 7 years to amortize the capital costs of CCS. As a result, for these sources, the overall costs of CCS would exceed the metrics for cost reasonableness that the EPA is using in

[685] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (87 FR 52224; August 24, 2022).

[686] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (84 FR 52180; October 1, 2019).

[687] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments (86 FR 63266; November 15, 2021).

this rulemaking, which are detailed in section VII.C.1.a.ii(D). For this reason, the EPA is not finalizing CCS as the BSER for the medium-term subcategory.

ii. Heat Rate Improvements

Heat rate improvements were not considered to be BSER for medium-term steam generating units because the achievable reductions are low and may result in rebound effect whereby total emissions from the source increase, as detailed in section VII.D.4.a.

d. Conclusion

The EPA is finalizing that natural gas co-firing at 40 percent of heat input is the BSER for medium-term coal-fired steam generating units because natural gas co-firing is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources. Additionally, the costs for natural gas co-firing are reasonable. Moreover, natural gas co-firing can be expected to reduce emissions of several other air pollutants in addition to GHGs. Any adverse non-air quality health and environmental impacts and energy requirements of natural gas co-firing are limited. In contrast, CCS, although achieving greater emission reductions, would be of higher cost, in general, for the subcategory of medium-term units, and HRI would achieve few reductions and, in fact, may increase emissions.

3. Degree of Emission Limitation for Final Standards

Under CAA section 111(d), once the EPA determines the BSER, it must determine the "degree of emission limitation" achievable by the application of the BSER. States then determine standards of performance and include them in the state plans, based on the specified degree of emission limitation. Final presumptive standards of performance are detailed in section X.C.1.b of this preamble. There is substantial variation in emission rates among coal-fired steam generating units—the range is, approximately, from 1,700 lb CO_2/MWh-gross to 2,500 lb CO_2/MWh-gross—which makes it challenging to determine a single, uniform emission limit. Accordingly, the EPA is finalizing the degrees of emission limitation by a percentage change in emission rate, as follows.

a. Long-Term Coal-Fired Steam Generating Units

As discussed earlier in this preamble, the EPA is finalizing the BSER for long-term coal-fired steam generating units as "full-capture" CCS, defined as 90 percent capture of the CO_2 in the flue gas. The degree of emission limitation achievable by applying this BSER can be determined on a rate basis. A capture rate of 90 percent results in reductions in the emission rate of 88.4 percent on a lb CO_2/MWh-gross basis, and this reduction in emission rate can be observed over an extended period (*e.g.*, an annual calendar-year basis). Therefore, the EPA is finalizing that the degree of emission limitation for long-term units is an 88.4 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.*, an annual calendar-year basis).

b. Medium-Term Coal-Fired Steam Generating Units

As discussed earlier in this preamble, the BSER for medium-term coal-fired steam generating units is 40 percent natural gas co-firing. The application of 40 percent natural gas co-firing results in reductions in the emission rate of 16 percent. Therefore, the degree of emission limitation for these units is a 16 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.*, an annual calendar-year basis).

D. Rationale for the BSER for Natural Gas-Fired And Oil-Fired Steam Generating Units

This section of the preamble describes the rationale for the final BSERs for existing natural gas- and oil-fired steam generating units based on the criteria described in section V.C of this preamble.

1. Subcategorization of Natural Gas- and Oil-Fired Steam Generating Units

The EPA is finalizing subcategories based on load level (*i.e.*, annual capacity factor), specifically, units that are base load, intermediate load, and low load. The EPA is finalizing routine methods of operation and maintenance as BSER for intermediate and base load units. Applying that BSER would not achieve emission reductions but would prevent increases in emission rates. The EPA is finalizing presumptive standards of performance that differ between intermediate and base load units due to their differences in operation, as detailed in section X.C.1.b.iii of this preamble. The EPA proposed a separate subcategory for non-continental oil-fired steam generating units, which operate differently from continental units; however, the EPA is not finalizing emission guidelines for sources outside of the contiguous U.S., as described in section VII.B. At proposal, the EPA solicited comment on a BSER of "uniform fuels" for low load natural gas- and oil-fired steam generating units, and the EPA is finalizing this approach for those sources.

Natural gas- and oil-fired steam generating units combust natural gas or distillate fuel oil or residual fuel oil in a boiler to produce steam for a turbine that drives a generator to create electricity. In non-continental areas, existing natural gas- and oil-fired steam generating units may provide base load power, but in the continental U.S., most existing units operate in a load-following manner. There are approximately 200 natural gas-fired steam generating units and fewer than 30 oil-fired steam generating units in operation in the continental U.S. Fuel costs and inefficiency relative to other technologies (*e.g.*, combustion turbines) result in operation at lower annual capacity factors for most units. Based on data reported to EIA and the EPA [688] for the contiguous U.S., for natural gas-fired steam generating units in 2019, the average annual capacity factor was less than 15 percent and 90 percent of units had annual capacity factors less than 35 percent. For oil-fired steam generating units in 2019, no units had annual capacity factors above 8 percent. Additionally, their load-following method of operation results in frequent cycling and a greater proportion of time spent at low hourly capacities, when generation is less efficient. Furthermore, because startup times for most boilers are usually long, natural gas steam generating units may operate in standby mode between periods of peak demand. Operating in standby mode requires combusting fuel to keep the boiler warm, and this further reduces the efficiency of natural gas combustion.

Unlike coal-fired steam generating units, the CO_2 emission rates of oil- and natural gas-fired steam generating units that have similar annual capacity factors do not vary considerably between units. This is partly due to the more uniform qualities (*e.g.*, carbon content) of the fuel used. However, the emission rates for units that have different annual capacity factors do vary considerably, as detailed in the final TSD, *Natural Gas- and Oil-fired Steam Generating Units.* Low annual capacity factor units cycle frequently, have a greater proportion of CO_2 emissions that may be attributed to startup, and have a greater proportion of generation at inefficient hourly capacities. Intermediate annual capacity factor units operate more often at higher hourly capacities, where CO_2 emission rates are lower. High annual capacity factor units operate still more at base load conditions, where units are more

[688] Clean Air Markets Program Data at *https://campd.epa.gov.*

efficient and CO_2 emission rates are lower.

Based on these performance differences between these load levels, the EPA, in general, proposed subcategories based on dividing natural gas- and oil-fired steam generating units into three groups each—low load, intermediate load, and base load.

The EPA is finalizing subcategories for oil-fired and natural gas-fired steam generating units, based on load levels. The EPA proposed the following load levels: ''low'' load, defined by annual capacity factors less than 8 percent; ''intermediate'' load, defined by annual capacity factors greater than or equal to 8 percent and less than 45 percent; and ''base'' load, defined by annual capacity factors greater than or equal to 45 percent.

The EPA is finalizing January 1, 2030, as the compliance date for natural gas- and oil-fired steam generating units and this date is consistent with the dates in the fuel type definitions.

The EPA received comments that were generally supportive of the proposed subcategory definitions,[689] and the EPA is finalizing the subcategory definitions as proposed.

2. Options Considered for BSER

The EPA has considered various methods for controlling CO_2 emissions from natural gas- and oil-fired steam generating units to determine whether they meet the criteria for BSER. Co-firing natural gas cannot be the BSER for these units because natural gas- and oil-fired steam generating units already fire large proportions of natural gas. Most natural gas-fired steam generating units fire more than 90 percent natural gas on a heat input basis, and any oil-fired steam generating units that would potentially operate above an annual capacity factor of around 15 percent typically combust natural gas as a large proportion of their fuel as well. Nor is CCS a candidate for BSER. The utilization of most gas-fired units, and likely all oil-fired units, is relatively low, and as a result, the amount of CO_2 available to be captured is low. However, the capture equipment would still need to be sized for the nameplate capacity of the unit. Therefore, the capital and operating costs of CCS would be high relative to the amount of CO_2 available to be captured. Additionally, again due to lower utilization, the amount of IRC section 45Q tax credits that owner/operators could claim would be low. Because of the relatively high costs and the relatively low cumulative emission reduction potential for these natural gas- and oil-fired steam generating units, the EPA is not determining CCS as the BSER for them.

The EPA has reviewed other possible controls but is not finalizing any of them as the BSER for natural gas- and oil-fired units either. Co-firing hydrogen in a boiler is technically possible, but there is limited availability of hydrogen now and in the near future and it should be prioritized for more efficient units. Additionally, for natural gas-fired steam generating units, setting a future standard based on hydrogen would likely have limited GHG reduction benefits given the low utilization of natural gas- and oil-fired steam generating units. Lastly, HRI for these types of units would face many of the same issues as for coal-fired steam generating units; in particular, HRI could result in a rebound effect that would increase emissions.

However, the EPA recognizes that natural gas- and oil-fired steam generating units could possibly, over time, operate more, in response to other changes in the power sector. Additionally, some coal-fired steam generating units have converted to 100 percent natural gas-fired, and it is possible that more may do so in the future. The EPA also received several comments from industry stating plans to do so. Moreover, in part because the fleet continues to age, the plants may operate with degrading emission rates. In light of these possibilities, identifying the BSER and degrees of emission limitation for these sources would be useful to provide clarity and prevent backsliding in GHG performance. Therefore, the EPA is finalizing BSER for intermediate and base load natural gas- and oil-fired steam generating units to be routine methods of operation and maintenance, such that the sources could maintain the emission rates (on a lb/MWh-gross basis) currently maintained by the majority of the fleet across discrete ranges of annual capacity factor. The EPA is finalizing this BSER for intermediate load and base load natural gas- and oil-fired steam generating units, regardless of the operating horizon of the unit.

A BSER based on routine methods of operation and maintenance is adequately demonstrated because units already operate with those practices. There are no or negligible additional costs because there is no additional technology that units are required to apply and there is no change in operation or maintenance that units must perform. Similarly, there are no adverse non-air quality health and environmental impacts or adverse impacts on energy requirements. Nor do they have adverse impacts on the energy sector from a nationwide or long-term perspective. The EPA's modeling, which supports this final rule, indicates that by 2040, a number of natural gas-fired steam generating units will have remained in operation since 2030, although at reduced annual capacity factors. There are no CO_2 reductions that may be achieved at the unit level, but applying routine methods of operation and maintenance as the BSER prevents increases in emission rates. Routine methods of operation and maintenance do not advance useful control technology, but this point is not significant enough to offset their benefits.

At proposal, the EPA also took comment on a potential BSER of uniform fuels for low load natural gas- and oil-fired steam generating units. As noted earlier in this preamble, non-coal fossil fuels combusted in utility boilers typically include natural gas, distillate fuel oil (*i.e.*, fuel oil No. 1 and No. 2), and residual fuel oil (*i.e.*, fuel oil No. 5 and No. 6). The EPA previously established heat-input based fuel composition as BSER in the 2015 NSPS (termed ''clean fuels'' in that rulemaking) for new non-base load natural gas- and multi-fuel-fired stationary combustion turbines (80 FR 64615–17; October 23, 2015), and the EPA is similarly finalizing lower-emitting fuels as BSER for new low load combustion turbines as described in section VIII.F of this preamble. For low load natural gas- and oil-fired steam generating units, the high variability in emission rates associated with the variability of load at the lower-load levels limits the benefits of a BSER based on routine maintenance and operation. That is because the high variability in emission rates would make it challenging to determine an emission rate (*i.e.*, on a lb CO_2/MWh-gross basis) that could serve as the presumptive standard of performance that would reflect application of a BSER of routine operation and maintenance. On the other hand, for those units, a BSER of ''uniform fuels'' and an associated presumptive standard of performance based on a heat input basis, as described in section X.C.1.b.iii of this preamble, is reasonable. Therefore, the EPA is finalizing a BSER of uniform fuels for low load natural gas- and oil-fired steam generating units, with presumptive standards depending on fuel type detailed in section X.C.1.b.iii.

[689] See, for example, Document ID No. EPA–HQ–OAR–2023–0072–0583.

3. Degree of Emission Limitation

As discussed above, because the BSER for base load and intermediate load natural gas- and oil-fired steam generating units is routine operation and maintenance, which the units are, by definition, already employing, the degree of emission limitation by application of this BSER is no increase in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*e.g.*, a year).

For low load natural gas- and oil-fired steam generating units, the EPA is finalizing a BSER of uniform fuels, with a degree of emission limitation on a heat input basis consistent with a fixed 130 lb CO_2/MMBtu for natural gas-fired steam generating units and 170 lb CO_2/MMBtu for oil-fired steam generating units. The degree of emission limitation for natural gas- and oil-fired steam generating units is higher than the corresponding values under 40 CFR part 60, subpart TTTT, because steam generating units may fire fuels with slightly higher carbon contents.

4. Other Emission Reduction Measures Not Considered BSER

a. Heat Rate Improvements

Heat rate is a measure of efficiency that is commonly used in the power sector. The heat rate is the amount of energy input, measured in Btu, required to generate 1 kilowatt-hour (kWh) of electricity. The lower an EGU's heat rate, the more efficiently it operates. As a result, an EGU with a lower heat rate will consume less fuel and emit lower amounts of CO_2 and other air pollutants per kWh generated as compared to a less efficient unit. HRI measures include a variety of technology upgrades and operating practices that may achieve CO_2 emission rate reductions of 0.1 to 5 percent for individual EGUs. The EPA considered HRI to be part of the BSER in the CPP and to be the BSER in the ACE Rule. However, the reductions that may be achieved by HRI are small relative to the reductions from natural gas co-firing and CCS. Also, some facilities that apply HRI would, as a result of their increased efficiency, increase their utilization and therefore increase their CO_2 emissions (as well as emissions of other air pollutants), a phenomenon that the EPA has termed the ''rebound effect.'' Therefore, the EPA is not finalizing HRI as a part of BSER.

i. CO_2 Reductions From HRI in Prior Rulemakings

In the CPP, the EPA quantified emission reductions achievable through heat rate improvements on a regional basis by an analysis of historical emission rate data, taking into consideration operating load and ambient temperature. The Agency concluded that EGUs can achieve on average a 4.3 percent improvement in the Eastern Interconnection, a 2.1 percent improvement in the Western Interconnection, and a 2.3 percent improvement in the Texas Interconnection. See 80 FR 64789 (October 23, 2015). The Agency then applied all three of the building blocks to 2012 baseline data and quantified, in the form of CO_2 emission rates, the reductions achievable in Each interconnection in 2030, and then selected the least stringent as a national performance rate. *Id.* at 64811–19. The EPA noted that building block 1 measures could not by themselves constitute the BSER because the quantity of emission reductions achieved would be too small and because of the potential for an increase in emissions due to increased utilization (*i.e.*, the ''rebound effect'').

ii. Updated CO_2 Reductions From HRI

The HRI measures include improvements to the boiler island (*e.g.*, neural network system, intelligent sootblower system), improvements to the steam turbine (*e.g.*, turbine overhaul and upgrade), and other equipment upgrades (*e.g.*, variable frequency drives). Some regular practices that may recover degradation in heat rate to recent levels—but that do not result in upgrades in heat rate over recent design levels and are therefore not HRI measures—include practices such as in-kind replacements and regular surface cleaning (*e.g.*, descaling, fouling removal). Specific details of the HRI measures are described in the final TSD, *GHG Mitigation Measures for Steam Generating Units* and an updated 2023 Sargent and Lundy HRI report (*Heat Rate Improvement Method Costs and Limitations Memo*), available in the docket. Most HRI upgrade measures achieve reductions in heat rate of less than 1 percent. In general, the 2023 Sargent and Lundy HRI report, which updates the 2009 Sargent and Lundy HRI report, shows that HRI achieve less reductions than indicated in the 2009 report, and shows that several HRI either have limited applicability or have already been applied at many units. Steam path overhaul and upgrade may achieve reductions up to 5.15 percent, with the average being around 1.5 percent. Different combinations of HRI measures do not necessarily result in cumulative reductions in emission rate (*e.g.*, intelligent sootblowing systems combined with neural network systems). Some of the HRI measures (*e.g.*, variable frequency drives) only impact heat rate on a net generation basis by reducing the parasitic load on the unit and would thereby not be observable for emission rates measured on a gross basis. Assuming many of the HRI measures could be applied to the same unit, adding together the upper range of some of the HRI percentages could yield an emission rate reduction of around 5 percent. However, the reductions that the fleet could achieve on average are likely much smaller. As noted, the 2023 Sargent and Lundy HRI report notes that, in many cases, units have already applied HRI upgrades or that those upgrades would not be applicable to all units. The unit level reductions in emission rate from HRI are small relative to CCS or natural gas co-firing. In the CPP and ACE Rule, the EPA viewed CCS and natural gas co-firing as too costly to qualify as the BSER; those costs have fallen since those rules and, as a result, CCS and natural gas co-firing do qualify as the BSER for the long-term and medium-term subcategories, respectively.

iii. Potential for Rebound in CO_2 Emissions

Reductions achieved on a rate basis from HRI may not result in overall emission reductions and could instead cause a ''rebound effect'' from increased utilization. A rebound effect would occur where, because of an improvement in its heat rate, a steam generating unit experiences a reduction in variable operating costs that makes the unit more competitive relative to other EGUs and consequently raises the unit's output. The increase in the unit's CO_2 emissions associated with the increase in output would offset the reduction in the unit's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of output. The extent of the offset would depend on the extent to which the unit's generation increased. The CPP did not consider HRI to be BSER on its own, in part because of the potential for a rebound effect. Analysis for the ACE Rule, where HRI was the entire BSER, observed a rebound effect for certain sources in some cases.[690] In this action, where different subcategories of units are to be subject to different BSER measures, steam generating units in a hypothetical subcategory with HRI as BSER could experience a rebound effect. Because of this potential for perverse GHG emission outcomes resulting from deployment of HRI at certain steam generating units, coupled with the

[690] 84 FR 32520 (July 8, 2019).

relatively minor overall GHG emission reductions that would be expected from this measure, the EPA is not finalizing HRI as the BSER for any subcategory of existing coal-fired steam generating units.

E. Additional Comments Received on the Emission Guidelines for Existing Steam Generating Units and Responses

1. Consistency With West Virginia v. EPA and the Major Questions Doctrine

Comment: Some commenters argued that the EPA's determination that CCS is the BSER for existing coal-fired power plants is invalid under *West Virginia* v. *EPA,* 597 U.S. 697 (2022), and the major questions doctrine (MQD). Commenters state that for various reasons, coal-fired power plants will not install CCS and instead will be forced to retire their units. They point to the EPA's IPM modeling which, they say, shows that many coal-fired power plants retire rather than install CCS. They add that, in this way, the rule effectively results in the EPA's requiring generation-shifting from coal-fired generation to renewable and other generation, and thus is like the Clean Power Plan (CPP). For those reasons, they state that the rule raises a major question, and further that CAA section 111(d) does not contain a clear authorization for this type of rule.

Response: The EPA discussed *West Virginia* and its articulation of the MQD in section V.B.6 of this preamble.

The EPA disagrees with these comments. This rule is fully consistent with the Supreme Court's interpretation of the EPA's authority in *West Virginia.* The EPA's determination that CCS—a traditional, add-on emissions control—is the BSER is consistent with the plain text of section 111. As explained in detail in section VII.C.1.a, for long-term coal-fired steam generating units, CCS meets all of the BSER factors: it is adequately demonstrated, of reasonable cost, and achieves substantial emissions reductions. That some coal-fired power plants will choose not to install emission controls and will instead retire does not raise major questions concerns.

In *West Virginia,* the U.S. Supreme Court held that ''generation-shifting'' as the BSER for coal- and gas-fired units ''effected a fundamental revision of the statute, changing it from one sort of scheme of regulation into an entirely different kind.'' 597 U.S. at 728 (internal quotation marks, brackets, and citation omitted). The Court explained that prior CAA section 111 rules were premised on ''more traditional air pollution control measures'' that ''focus on improving the performance of individual sources.'' *Id.* at 727 (citing ''fuel-switching'' and ''add-on controls''). The Court said that generation-shifting as the BSER was ''unprecedented'' because it was designed to ''improve the overall power system by lowering the carbon intensity of power generation . . . by forcing a shift throughout the power grid from one type of energy source to another.'' *Id.* at 727–28 (internal quotation marks, emphasis, and citation omitted). The Court cited statements by the then-Administrator describing the CPP as ''not about pollution control so much as it was an investment opportunity for States, especially investments in renewables and clean energy.'' *Id.* at 728. The Court further concluded that the EPA's view of its authority was virtually unbounded because the ''EPA decides, for instance, how much of a switch from coal to natural gas is practically feasible by 2020, 2025, and 2030 before the grid collapses, and how high energy prices can go as a result before they become unreasonably exorbitant.'' *Id.* at 729.

Here, the EPA's determination that CCS is the BSER does not affect a fundamental revision of the statute, nor is it unbounded. CCS is not directed at improvement of the overall power system. Rather, CCS is a traditional ''add-on [pollution] control[ ]'' akin to measures that the EPA identified as BSER in prior CAA section 111 rules. *See id.* at 727. It ''focus[es] on improving the performance of individual sources''—it reduces CO_2 pollution from each individual source—because each affected source is able to apply it to its own facility to reduce its own emissions. *Id.* at 727. Further, the EPA determined that CCS qualifies as the BSER by applying the criteria specified in CAA section 111(a)(1)—including adequate demonstration, costs of control, and emissions reductions. *See* section VII.C.1.a of this preamble. Thus, CCS as the BSER does not ''chang[e]'' the statute ''from one sort of scheme of regulation into an entirely different kind.'' *Id.* at 728 (internal quotation marks, brackets, and citation omitted).

Commenters contend that notwithstanding these distinctions, the choice of CCS as the BSER has the *effect* of shifting generation because modeling projections for the rule show that coal-fired generation will become less competitive, and gas-fired and renewable-generated electricity will be more competitive and dispatched more frequently. That some coal-fired sources may retire rather than reduce their CO_2 pollution does not mean that the rule ''represents a transformative expansion [of EPA's] regulatory authority''. *Id.* at 724. To be sure, this rule's determination that CCS is the BSER imposes compliance costs on coal-fired power plants. That sources will incur costs to control their emissions of dangerous pollution is an unremarkable consequence of regulation, which, as the Supreme Court recognized, ''may end up causing an incidental loss of coal's market share.'' *Id.* at 731 n.4.[691] Indeed, ensuring that sources internalize the full costs of mitigating their impacts on human health and the environment is a central purpose of traditional environmental regulation.

In particular, for the power sector, grid operators constantly shift generation as they dispatch electricity from sources based upon their costs. The EPA's IPM modeling, which is based on the costs of the various types of electricity generation, projects these impacts. Viewed as a whole, these projected impacts show that, collectively, coal-fired power plants will likely produce less electricity, and other sources (like gas-fired units and renewable sources) will likely produce more electricity, but this pattern does not constitute a transformative expansion of statutory authority (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends.*)

These projected impacts are best understood by comparing the IPM model's ''base case,'' *i.e.,* the projected electricity generation without any rule in place, to the model's ''policy case,'' *i.e.,* the projected electricity generation expected to result from this rule. The base case projects that many coal-fired units will retire over the next 20 years (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*). Those projected retirements track trends over the past two decades where coal-fired units have retired in high numbers because gas-fired units and renewable sources have become increasingly able to generate lower-cost electricity. As more gas-fired and renewable generation sources deploy in the future, and as coal-fired units continue to age—which results in decreased efficiency and increased costs—the coal-fired units will become increasingly marginal and continue to retire (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends.*) That is true in the absence of this rule. The EPA's modeling results also project that even if the EPA had

[691] As discussed in section VII.C.1.a.ii.(D), the costs of CCS are reasonable based on the EPA's $/MWh and $/ton metrics. As discussed in RTC section 2.16, the total annual costs of this rule are a small fraction of the revenues and capital costs of the electric power industry.

determined BSER for long-term sources to be 40 percent co-firing, which requires significantly less capital investment, and not 90 percent capture CCS, a comparable number of sources would retire instead of installing controls. These results confirm that the primary cause for the projected retirements is the marginal profitability of the sources.

Importantly, the base-case projections also show that some coal-fired units install CCS and run at high capacity factors, in fact, higher than they would have had they not installed CCS. This is because the IRC section 45Q tax credit significantly reduces the variable cost of operation for qualifying sources. This incentivizes sources to increase generation to maximize the tons of CO_2 the CCS equipment captures, and thereby increase the amount of the tax credit they receive. In the ''policy case,'' beginning when the CCS requirement applies in the 2035 model year,[692] some additional coal-fired units will likely install CCS, and also run at high capacity factors, again, significantly higher than they would have without CCS. Other units may retire rather than install emission controls (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*). On balance, the coal-fired units that install CCS collectively generate nearly the same amount of electricity in the 2040 model year as do the group of coal-fired units in the base case.

The policy case also shows that in the 2045 model year, by which time the 12-year period for sources to claim the IRC section 45Q tax credit will have expired, most sources that install CCS retire due to the costs of meeting the CCS-based standards without the benefit of the tax credit. However, in fact, these projected outcomes are far from certain as the modeling results generally do not account for numerous potential changes that may occur over the next 20 or more years, any of which may enable these units to continue to operate economically for a longer period. Examples of potential changes include reductions in the operational costs of CCS through technological improvements, or the development of additional potential revenue streams for captured CO_2 as the market for beneficial uses of CO_2 continues to develop, among other possible changed economic circumstances (including the possible extension of the tax credits). In light of these potential significant developments, the EPA is committing to review and, if appropriate, revise the requirements of this rule by January 1, 2041, as described in section VII.F.

In any event, the modeling projections showing that many sources retire instead of installing controls are in line with the trends for these units in the absence of the rule—as the coal-fired fleet ages and lower-cost alternatives become increasingly available, more operators will retire coal-fired units with or without this rule. In 2045, the average age of coal-fired units that have not yet announced retirement dates or coal-to-gas conversion by 2039 will be 61 years old. And, on average, between 2000 and 2022, even in the absence of this rule, coal-fired units generally retired at 53 years old. Thus, taken as a whole, this rule does not dramatically reduce the expected operating horizon of most coal-fired units. Indeed, for units that install CCS, the generous IRC section 45Q tax credit increases the competitiveness of these units, and it allows them to generate more electricity with greater profit than the sources would otherwise generate if they did not install CCS.

The projected effects of the rule do not show the BSER—here, CCS—is akin to generation shifting, or otherwise represents an expansion of EPA authority with vast political or economic significance. As described above at VII.C.1.a.ii, CCS is an affordable emissions control technology. It is also very effective, reducing CO_2 emissions from coal-fired units by 90 percent, as described in section VII.C.1.a.i. Indeed, as noted, the IRA tax credits make CCS so affordable that coal-fired units that install CCS run at higher capacity factors than they would otherwise.

Considered as a whole, and in context with historical retirement trends, the projected impacts of this rule on coal-fired generating units do not raise MQD concerns. The projected impacts are merely incidental to the CCS control itself—the unremarkable consequence of marginally increasing the cost of doing business in a competitive market. Nor is the rule ''transformative.'' The rule does not ''announce what the market share of coal, natural gas, wind, and solar must be, and then requiring plants to reduce operations or subsidize their competitors to get there.'' 597 U.S. at 731 n.4. As noted above, coal-fired units that install CCS are projected to generate substantial amounts of electricity. The retirements that are projected to occur are broadly consistent with market trends over the past two decades, which show that coal-fired electricity production is generally less economic and less competitive than other forms of electricity production. That is, the retirements that the model predicts under this rule, and the structure of the industry that results, diverge little from the prior rate of retirements of coal-fired units over the past two decades. They also diverge little from the rate of retirements from sources that have already announced that they will retire, or from the additional retirements that IPM projects will occur in the base case (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*).

As discussed above, because much of the coal-fired fleet is operating on the edge of viability, many sources would retire instead of installing any meaningful CO_2 emissions control—whether CCS, natural gas co-firing, or otherwise. Under commenters' view that such retirements create a major question, *any* form of meaningful regulation of these sources would create a major question and effect a fundamental revision of the statute. That cannot possibly be so. Section 111(d)(1) plainly mandates regulation of these units, which are the biggest stationary source of dangerous CO_2 emissions.

The legislative history for the CAA further makes clear that Congress intended the EPA to promulgate regulations even where emissions controls had economic costs. At the time of the 1970 CAA Amendments, Congress recognized that the threats of air pollution to public health and welfare had grown urgent and severe. Sen. Edmund Muskie (D–ME), manager of the bill and chair of the Public Works Subcommittee on Air and Water Pollution, which drafted the bill, regularly referred to the air pollution problem as a ''crisis.'' As Sen. Muskie recognized, ''Air pollution control will be cheap only in relation to the costs of lack of control.'' [693] The Senate Committee Report for the 1970 CAA Amendments specifically discussed the precursor provision to section 111(d) and noted, ''there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.'' [694] Accordingly, some of the

[692] Under the rule, sources are required to meet their CCS-based standard of performance by January 1, 2032. IPM groups calendar years into 5-year periods, *e.g.,* the 2035 model year and the 2040 model year. January 1, 2032, falls into the 2035 model year.

[693] Sen. Muskie, Sept. 21, 1970, LH 226.

[694] S. Rep. No. 91–1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)). Note that in the 1977 CAA Amendments, the House Committee Report made a similar statement. H.R. Rep. No. 95–294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring EPA to

EPA's prior CAA section 111 rulemakings have imposed stringent requirements, at significant cost, in order to achieve significant emission reductions.[695]

Congress's enactment of the IRA and IIJA further shows its view that reducing air pollution—specifically, in those laws, GHG emissions to address climate change—is a high priority. As discussed in section IV.E.1, that law provided funds for DOE grant and loan programs to support CCS, and extended and increased the IRC section 45Q tax credit for carbon capture. It also adopted the Low Emission Electricity Program (LEEP), which allocates funds to the EPA for the express purpose of using CAA regulatory authority to reduce GHG emissions from domestic electricity generation through use of its existing CAA authorities. CAA section 135, added by IRA section 60107. The EPA is promulgating the present rulemaking with those funds. The congressional sponsor of the LEEP made clear that it authorized the type of rulemaking that the EPA is promulgating today: he stated that the EPA may promulgate rulemaking under CAA section 111, based on CCS, to address CO_2 emissions from fossil fuel-fired power plants, which may be "impactful" by having the "incidental effect" of leading some "companies . . . to choose to retire such plants. . . ."[696]

For these reasons, the rule here is consistent with the Supreme Court's decision in *West Virginia*. The selection of CCS as the BSER for existing coal-fired units is a traditional, add-on control intended to reduce the emissions performance of individual sources. That some sources may retire instead of controlling their emissions does not otherwise show that the rule runs afoul of the MQD. The modeling projections for this rule show that the anticipated retirements are largely consistent with historical trends, and due to many coal-fired units' advanced age and lack of competitiveness with lower cost methods of electricity generation.

2. Redefining the Source

Comment: Some commenters contended that the proposed 40 percent natural gas co-firing performance standard violates legal precedent that bars the EPA from setting technology-based performance standards that would have the effect of "redefining the source." They stated that this prohibition against the redefinition of the source bars the EPA from adopting the proposed performance standard for medium-term coal-fired EGUs, which requires such units to operate in a manner for which the unit was never designed to do, namely operate as a hybrid coal/natural gas co-firing generating unit and combusting 40 percent of its fuel input as natural gas (instead of coal) on an annual basis.

Commenters argued that co-firing would constitute forcing one type of source to become an entirely different kind of source, and that the Supreme Court precluded such a requirement in *West Virginia* v. *EPA* when it stated in footnote 3 of that case that the EPA has "never ordered anything remotely like" a rule that would "simply require coal plants to become natural gas plants" and the Court "doubt[ed that EPA] could."[697]

Response: The EPA disagrees with these comments.

Standards based on co-firing, as contemplated in this rule, are based on a "traditional pollution control measure," in particular, "fuel switching," as the Supreme Court recognized in *West Virginia*.[698] Rules based on switching to a cleaner fuel are authorized under the CAA, an authorization directly acknowledged by Congress. Specifically, as part of the 1977 CAA Amendments, Congress required that the EPA base its standards regulating certain new sources, including power plants, on "technological" controls, rather than simply the "best system."[699] Congress understood this to mean that new sources would be required to implement add-on controls, rather than merely relying on fuel switching, and noted that one of the purposes of this amendment was to allow new sources to burn high sulfur coal while still decreasing emissions, and thus to increase the availability of low sulfur coal for existing sources, which were not subject to the "technological" control requirement.[700] In 1990, however, Congress removed the "technological" language, allowing the EPA to set fuel-switching based standards for both new and existing power plants.[701]

The EPA has a tradition of promulgating rules based on fuel switching. For example, the 2006 NSPS for stationary compression ignition internal combustion engines required the use of ultra-low sulfur diesel.[702] Similarly, in the 2015 NSPS for EGUs,[703] the EPA determined that the BSER for peaking plants was to burn primarily natural gas, with distillate oil used only as a backup fuel.[704] Nor is this approach unique to CAA section 111; in the 2016 rule setting section 112 standards for hazardous air pollutant emissions from area sources, for example, the EPA finalized an alternative particulate matter (PM) standard that specified that certain oil-fired boilers would meet the applicable

study and then take action to regulate radioactive air pollutants and three other air pollutants).

[695] *See Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding NSPS imposing controls on SO_2 emissions from coal-fired power plants when the "cost of the new controls . . . is substantial. EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.").

[696] 168 Cong. Rec. E868 (August 23, 2022) (statement of Rep. Frank Pallone, Jr.); *id.* E879 (August 26, 2022) (statement of Rep. Frank Pallone, Jr.).

[697] West Virginia v. EPA, 597 U.S, 697, 728 n.3 (2022).

[698] See 597 U.S. at 727.

[699] In 1977, Congress clarified that for purposes of CAA section 111(a)(1)(A), concerning standards of performance for new and modified "fossil fuel-fired stationary sources" a standard or performance "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best *technological* system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." Clean Air Act 1977 Revisions (emphasis added).

[700] *See* H. Rep. No. 94–1175, 94th Cong., 2d Sess. (May 15, 1976) Part A, at 159 (listing the various purposes of the amendment to Section 111 adding the term 'technological': "Fourth, by using best control technology on large new fuel-burning stationary sources, these sources could burn higher sulfur fuel than if no technological means of reducing emissions were used. This means an expansion of the energy resources that could be burned in compliance with environmental requirements. Fifth, since large new fuel-burning sources would not rely on naturally low sulfur coal or oil to achieve compliance with new source performance standards, the low sulfur coal or oil that would have been burned in these major new sources could instead be used in older and smaller sources.")

[701] In 1990, Congress removed this reference to a "technological system", and the current text reads simply: "The term "standard of performance" means 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." 42 U.S.C. 7411(a)(1).

[702] Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 71 FR 39154 (July 11, 2006). In the preamble to the final rule, the EPA noted that for engines which had not previously used this new ultra-low sulfur fuel, additives would likely need to be added to the fuel to maintain appropriate lubricity. *See id.* at 39158.

[703] Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 FR 64510, (October 23, 2015).

[704] *See id.* at 64621.

standard if they combusted only ultra-low-sulfur liquid fuel.[705]

Moreover, the *West Virginia* Court's statements in footnote 3 are irrelevant to the question of the validity of a 40 percent co-firing standard. There, the Court was referring to a complete transformation of the coal-fired unit to a 100 percent gas fired unit—a change that would require entirely repowering the unit. By contrast, increasing co-firing at existing coal-fired units to 40 percent would require only minor changes to the units' boilers. In fact, many coal-fired units are already capable of co-firing some amount of gas without any changes at all, and several have fired at 40 percent and above in recent years. Of the 565 coal-fired EGUs operating at the end of 2021, 249 of them reported consuming natural gas as a fuel or startup source, 162 reported more than one month of consumption of natural gas at their boiler, and 29 co-fired at over 40 percent on an annual heat input basis in at least one year while also operating with annual capacity factors greater than 10 percent. For more on this, see section IV.C.2 of this preamble; see also the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

F. Commitment To Review and, if Appropriate, Revise Emission Guidelines for Coal-Fired Units

The EPA recognizes that the IRC 45Q tax credit is a key component to the cost of CCS, as discussed in section VII.C.1.a.ii(C) of this preamble. The EPA further recognizes that for any affected source, the tax credit is currently available for a 12-year period and not subsequently. The tax credit is generally sufficient to defray the capital costs of CCS and much, if not all, of the operating costs during that 12-year period. Following the 12-year period, affected sources that continue to operate the CCS equipment would have higher costs of generation, due to the CCS operating costs, including parasitic load. Under certain circumstances, these higher costs could push the affected sources lower on the dispatch curve, and thereby lead to reductions in the amount of their generation, *i.e.*, if affected sources are not able to replace the revenue from the tax credit with revenue from other sources, or if the price of electricity does not reflect any additional costs needed to minimize GHG emissions.

[705] *See* National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 81 FR 63112–01 (September 14, 2016).

However, the costs of CCS and the overall economic viability of operating CO_2 capture at power plants are improving and can be expected to continue to improve in years to come. CO_2 that is captured from fossil-fuel fired sources is currently beneficially used, including, for example, for enhanced oil recovery and in the food and beverage industry. There is much research into developing beneficial uses for many other industries, including construction, chemical manufacturing, graphite manufacturing. The demand for CO_2 is expected to grow considerably over the next several decades. As a result, in the decades to come, affected sources may well be able to replace at least some of the revenues from the tax credit with revenues from the sale of CO_2. We discuss these potential developments in chapter 2 of the Response to Comments document, available in the rulemaking docket.

In addition, numerous states have imposed requirements to decarbonize generation within their borders. Many utilities have also announced plans to decarbonize their fleet, including building small modular (advanced nuclear) reactors. Given the relatively high capital and fixed costs of small modular reactors, plans for their construction represent an expectation of higher future energy prices. This suggests that, in the decades to come, at least in certain areas of the country, affected sources may be able to maintain a place in the dispatch curve that allows them to continue to generate while they continue to operate CCS, even in the absence of additional revenues for CO_2. We discuss these potential developments in the final TSD, *Power Sector Trends,* available in the rulemaking docket.

These developments, which may occur by the 2040s—the expiration of the 12-year period for the IRC 45Q tax credit, the potential development of the CO_2 utilization market, and potential market supports for low-GHG generation—may significantly affect the costs to coal-fired steam EGUs of operating their CCS controls. As a result, the EPA will closely monitor these developments. Our efforts will include consulting with other agencies with expertise and information, including DOE, which currently has a program, the Carbon Conversion Program, in the Office of Carbon Management, that funds research into CO_2 utilization. We regularly consult with stakeholders, including industry stakeholders, and will continue to do so.

In light of these potential significant developments and their impacts, potentially positive or negative, on the economics of continued generation by affected sources that have installed CCS, the EPA is committing to review and, if appropriate, revise this rule by January 1, 2041. This commitment is included in the regulations that the EPA is promulgating with this rule. The EPA will conduct this review based on what we learn from monitoring these developments, as noted above. Completing this review and any appropriate revisions by that date will allow time for the states to revise, if necessary, standards applicable to affected sources, and for the EPA to act on those state revisions, by the early to mid-2040s. That is when the 12-year period for the 45Q tax credit is expected to expire for affected sources that comply with the CCS requirement by January 1, 2032, and when other significant developments noted above may be well underway.

VIII. Requirements for New and Reconstructed Stationary Combustion Turbine EGUs and Rationale for Requirements

A. Overview

This section discusses the requirements for stationary combustion turbine EGUs that commence construction or reconstruction after May 23, 2023. The requirements are codified in 40 CFR part 60, subpart TTTTa. The EPA explains in section VIII.B of this document the two basic turbine technologies that are used in the power sector and are covered by 40 CFR part 60, subpart TTTTa. Those are simple cycle combustion turbines and combined cycle combustion turbines. The EPA also explains how these technologies are used in the three subcategories: low load turbines, intermediate load turbines, and base load turbines. Section VIII.C provides an overview of how stationary combustion turbines have been previously regulated. Section VIII.D discusses the EPA's decision to revisit the standards for new and reconstructed turbines as part of the statutorily required 8-year review of the NSPS. Section VIII.E discusses changes that the EPA is finalizing in both applicability and subcategories in the new 40 CFR part 60, subpart TTTTa, as compared to those codified previously in 40 CFR part 60, subpart TTTT. Most notably, for new and reconstructed natural gas-fired combustion turbines, the EPA is finalizing BSER determinations and standards of performance for the three subcategories mentioned above—low load, intermediate load, and base load.

Sections VIII.F and VIII.G of this document discuss the EPA's determination of the BSER for each of the three subcategories of combustion turbines and the applicable standards of performance, respectively. For low load combustion turbines, the EPA is finalizing a determination that the use of lower-emitting fuels is the appropriate BSER. For intermediate load combustion turbines, the EPA is finalizing a determination that highly efficient simple cycle generation is the appropriate BSER. For base load combustion turbines, the EPA is finalizing a determination that the BSER includes two components that correspond initially to a two-phase standard of performance. The first component of the BSER, with an immediate compliance date (phase 1), is highly efficient generation based on the performance of a highly efficient combined cycle turbine and the second component of the BSER, with a compliance date of January 1, 2032 (phase 2), is based on the use of CCS with a 90 percent capture rate, along with continued use of highly efficient generation. For base load turbines, the standards of performance corresponding to both components of the BSER would apply to all new and reconstructed sources that commence construction or reconstruction after May 23, 2023. The EPA occasionally refers to these standards of performance as the phase 1 or phase 2 standards.

B. Combustion Turbine Technology

For purposes of 40 CFR part 60, subparts TTTT and TTTTa, stationary combustion turbines include both simple cycle and combined cycle EGUs. Simple cycle turbines operate in the Brayton thermodynamic cycle and include three primary components: a multi-stage compressor, a combustion chamber (*i.e.,* combustor), and a turbine. The compressor is used to supply large volumes of high-pressure air to the combustion chamber. The combustion chamber converts fuel to heat and expands the now heated, compressed air through the turbine to create shaft work. The shaft work drives an electric generator to produce electricity. Combustion turbines that recover the energy in the high-temperature exhaust—instead of venting it directly to the atmosphere—are combined cycle EGUs and can obtain additional useful electric output. A combined cycle EGU includes an HRSG operating in the Rankine thermodynamic cycle. The HRSG receives the high-temperature exhaust and converts the heat to mechanical energy by producing steam that is then fed into a steam turbine that, in turn, drives an electric generator. As the thermal efficiency of a stationary combustion turbine EGU is increased, less fuel is burned to produce the same amount of electricity, with a corresponding decrease in fuel costs and lower emissions of CO_2 and, generally, of other air pollutants. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process.

Combustion turbines serve various roles in the power sector. Some combustion turbines operate at low annual capacity factors and are available to provide temporary power during periods of high load demand. These turbines are often referred to as ‘‘peaking units.’’ Some combustion turbines operate at intermediate annual capacity factors and are often referred to as cycling or load-following units. Other combustion turbines operate at high annual capacity factors to serve base load demand and are often referred to as base load units. In this rulemaking, the EPA refers to these types of combustion turbines as low load, intermediate load, and base load, respectively.

Low load combustion turbines provide reserve capacity, support grid reliability, and generally provide power during periods of peak electric demand. As such, the units may operate at or near their full capacity, but only for short periods, as needed. Because these units only operate occasionally, capital expenses are a major factor in the overall cost of electricity, and often, the lowest capital cost (and generally less efficient) simple cycle EGUs are intended for use only during periods of peak electric demand. Due to their low efficiency, these units require more fuel per MWh of electricity produced and their operating costs tend to be higher. Because of the higher operating costs, they are generally some of the last units in the dispatch order. Important characteristics for low load combustion turbines include their low capital costs, their ability to start quickly and to rapidly ramp up to full load, and their ability to operate at partial loads while maintaining acceptable emission rates and efficiencies. The ability to start quickly and rapidly attain full load is important to maximize revenue during periods of peak electric prices and to meet sudden shifts in demand. In contrast, under steady-state conditions, more efficient combined cycle EGUs are dispatched ahead of low load turbines and often operate at higher annual capacity factors.

Highly efficient simple cycle turbines and flexible fast-start combined cycle turbines both offer different advantages and disadvantages when operating at intermediate loads. One of the roles of these intermediate or load following EGUs is to provide dispatchable backup power to support variable renewable generating sources (*e.g.,* solar and wind). A developer's decision as to whether to build a simple cycle turbine or a combined cycle turbine to serve intermediate load demand is based on several factors related to the intended operation of the unit. These factors would include how frequently the unit is expected to cycle between starts and stops, the predominant load level at which the unit is expected to operate, and whether this level of operation is expected to remain consistent or is expected to vary over the lifetime of the unit. In areas of the U.S. with vertically integrated electricity markets, utilities determine dispatch orders based generally on economic merit of individual units. Meanwhile, in areas of the U.S. inside organized wholesale electricity markets, owner/operators of individual combustion turbines control whether and how units will operate over time, but they do not necessarily control the precise timing of dispatch for units in any given day or hour. Such short-term dispatch decisions are often made by regional grid operators that determine, on a moment-to-moment basis, which available individual units should operate to balance supply and demand and other requirements in an optimal manner, based on operating costs, price bids, and/or operational characteristics. However, operating permits for simple cycle turbines often contain restrictions on the annual hours of operation that owners/operators incorporate into longer-term operating plans and short-term dispatch decisions.

Intermediate load combustion turbines vary their generation, especially during transition periods between low and high electric demand. Both high-efficiency simple cycle turbines and flexible fast-start combined cycle turbines can fill this cycling role. While the ability to start quickly and quickly ramp up is important, efficiency is also an important characteristic. These combustion turbines generally have higher capital costs than low load combustion turbines but are generally less expensive to operate.

Base load combustion turbines are designed to operate for extended periods at high loads with infrequent starts and stops. Quick-start capability and low capital costs are less important than low operating costs. High-efficiency combined cycle turbines typically fill the role of base load combustion turbines.

The increase in generation from variable renewable energy sources during the past decade has impacted the way in which dispatchable generating resources operate.[706] For example, the electric output from wind and solar generating sources fluctuates daily and seasonally due to increases and decreases in the wind speed or solar intensity. Due to this variable nature of wind and solar, dispatchable EGUs, including combustion turbines as well as other technologies like energy storage, are used to ensure the reliability of the electric grid. This requires dispatchable power plants to have the ability to quickly start and stop and to rapidly and frequently change load—much more often than was previously needed. These are important characteristics of the combustion turbines that provide firm backup capacity. Combustion turbines are much more flexible than coal-fired utility boilers in this regard and have played an important role during the past decade in ensuring that electric supply and demand are balanced.

As discussed in section IV.F.2 of this preamble, in the final TSD, *Power Sector Trends,* and in the accompanying RIA, the EPA's Power Sector Platform 2023 using IPM 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. Energy storage technologies can store energy during periods when generation from renewable resources is high relative to demand and can provide electricity to the grid during other periods. Energy storage technologies are projected to reduce the need for base load fossil fuel-fired firm dispatchable power plants, and the capacity factors of combined cycle EGUs are forecast to decline by 2040.

C. Overview of Regulation of Stationary Combustion Turbines for GHGs

As explained earlier in this preamble, the EPA originally regulated new and reconstructed stationary combustion turbine EGUs for emissions of GHGs in 2015 under 40 CFR part 60, subpart TTTT. In 40 CFR part 60, subpart TTTT, the EPA created three subcategories: two for natural gas-fired combustion turbines and one for multi-fuel-fired combustion turbines. For natural gas-fired turbines, the EPA created a subcategory for base load turbines and a separate subcategory for non-base load turbines. Base load turbines were defined as combustion turbines with electric sales greater than a site-specific electric sales threshold based on the design efficiency of the combustion turbine. Non-base load turbines were defined as combustion turbines with a capacity factor less than or equal to the site-specific electric sales threshold. For base load turbines, the EPA set a standard of 1,000 lb CO_2/MWh-gross based on efficient combined cycle turbine technology. For non-base load and multi-fuel-fired turbines, the EPA set a standard based on the use of lower-emitting fuels that varied from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending upon whether the turbine burned primarily natural gas or other lower-emitting fuels.

D. Eight-Year Review of NSPS

CAA section 111(b)(1)(B) requires the Administrator to "at least every 8 years, review and, if appropriate, revise [the NSPS] . . . ." The provision further provides that "the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such [NSPS]."

The EPA promulgated the NSPS for GHG emissions for stationary combustion turbines in 2015. Announcements and modeling projections show that project developers are building new fossil fuel-fired combustion turbines and have plans to continue building additional capacity. Because the emissions from this added capacity have the potential to be large and these units are likely to have long operating lives (25 years or more), it is important to limit emissions from these new units. Accordingly, in this final rule, the EPA is updating the NSPS for newly constructed and reconstructed fossil fuel-fired stationary combustion turbines.

E. Applicability Requirements and Subcategorization

This section describes the amendments to the specific applicability criteria for non-fossil fuel-fired EGUs, industrial EGUs, CHP EGUs, and combustion turbine EGUs not connected to a natural gas pipeline. The EPA is also making certain changes to the applicability requirements for stationary combustion turbines affected by this final rule as compared to those for sources affected by the 2015 NSPS. The amendments are described below and include the elimination of the multi-fuel-fired subcategory, further binning non-base load combustion turbines into low load and intermediate load subcategories and establishing a capacity factor threshold for base load combustion turbines.

1. Applicability Requirements

In general, the EPA refers to fossil fuel-fired EGUs that would be subject to a CAA section 111 NSPS as "affected" EGUs or units. An EGU is any fossil fuel-fired electric utility steam generating unit (*i.e.*, a utility boiler or IGCC unit) or stationary combustion turbine (in either simple cycle or combined cycle configuration). To be considered an affected EGU under the 2015 NSPS at 40 CFR part 60, subpart TTTT, the unit must meet the following applicability criteria: The unit must: (1) be capable of combusting more than 250 MMBtu/h (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.*, for sale to the grid).[707] However, 40 CFR part 60, subpart TTTT, includes applicability exemptions for certain EGUs, including: (1) non-fossil fuel-fired units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis; (2) CHP units that are subject to a federally enforceable permit limiting annual net electric sales to no more than either the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh, whichever is greater; (3) stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.*, those that are not connected to a natural gas pipeline); (4) utility boilers and IGCC units that have always been subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.*, limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (5) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (6) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (7) certain projects under development, as discussed in the preamble for the 2015 final NSPS.

[706] Dispatchable generating sources are those that can be turned on and off and adjusted to provide power to the electric grid based on the demand for electricity. Variable (sometimes referred to as intermittent) generating sources are those that supply electricity based on external factors that are not controlled by the owner/operator of the source (*e.g.*, wind and solar sources).

[707] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the "base load rating criterion." Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

a. Revisions to 40 CFR Part 60, Subpart TTTT

The EPA is amending 40 CFR 60.5508 and 60.5509 to reflect that stationary combustion turbines that commenced construction after January 8, 2014, or reconstruction after June 18, 2014, and before May 24, 2023, and that meet the relevant applicability criteria are subject to 40 CFR part 60, subpart TTTT. For steam generating EGUs and IGCC units, 40 CFR part 60, subpart TTTT, remains applicable for units constructed after January 8, 2014, or reconstructed after June 18, 2014. The EPA is finalizing 40 CFR part 60, subpart TTTTa, to be applicable to stationary combustion turbines that commence construction or reconstruction after May 23, 2023, and that meet the relevant applicability criteria.

b. Revisions to 40 CFR Part 60, Subpart TTTT, That Are Also Included in 40 CFR Part 60, Subpart TTTTa

The EPA is finalizing that 40 CFR part 60, subpart TTTT, and 40 CFR part 60, subpart TTTTa, use similar regulatory text except where specifically stated. This section describes amendments included in both subparts.

i. Applicability to Non-Fossil Fuel-Fired EGUs

The current non-fossil applicability exemption in 40 CFR part 60, subpart TTTT, is based strictly on the combustion of non-fossil fuels (*e.g.*, biomass). To be considered a non-fossil fuel-fired EGU, the EGU must be both: (1) Capable of combusting more than 50 percent non-fossil fuel and (2) subject to a federally enforceable permit condition limiting the annual heat input capacity for all fossil fuels combined of 10 percent or less. The current language does not take heat input from non-combustion sources (*e.g.*, solar thermal) into account. Certain solar thermal installations have natural gas backup burners larger than 250 MMBtu/h. As currently treated in 40 CFR part 60, subpart TTTT, these solar thermal installations are not eligible to be considered non-fossil units because they are not capable of deriving more than 50 percent of their heat input from the combustion of non-fossil fuels. Therefore, solar thermal installations that include backup burners could meet the applicability criteria of 40 CFR part 60, subpart TTTT, even if the burners are limited to an annual capacity factor of 10 percent or less. These EGUs would readily comply with the standard of performance, but the reporting and recordkeeping would increase costs for these EGUs.

The EPA proposed and is finalizing several amendments to align the applicability criteria with the original intent to cover only fossil fuel-fired EGUs. These amendments ensure that solar thermal EGUs with natural gas backup burners, like other types of non-fossil fuel-fired units that derive most of their energy from non-fossil fuel sources, are not subject to the requirements of 40 CFR part 60, subpart TTTT or TTTTa. Amending the applicability language to include heat input derived from non-combustion sources allows these facilities to avoid the requirements of 40 CFR part 60, subpart TTTT or TTTTa, by limiting the use of the natural gas burners to less than 10 percent of the capacity factor of the backup burners. Specifically, the EPA is amending the definition of non-fossil fuel-fired EGUs from EGUs capable of "combusting 50 percent or more non-fossil fuel" to EGUs capable of "*deriving* 50 percent or more *of the heat input from* non-fossil fuel *at the base load rating*" (emphasis added). The definition of base load rating is also being amended to include the heat input from non-combustion sources (*e.g.*, solar thermal).

Revising "combusting" to "deriving" in the amended non-fossil fuel applicability language ensures that 40 CFR part 60, subparts TTTT and TTTTa, cover the fossil fuel-fired EGUs that the original rule was intended to cover, while minimizing unnecessary costs to EGUs fueled primarily by steam generated without combustion (*e.g.*, thermal energy supplied through the use of solar thermal collectors). The corresponding change in the base load rating to include the heat input from non-combustion sources is necessary to determine the relative heat input from fossil fuel and non-fossil fuel sources.

ii. Industrial EGUs

(A) Applicability to Industrial EGUs

In simple terms, the current applicability provisions in 40 CFR part 60, subpart TTTT, require that an EGU be capable of combusting more than 250 MMBtu/h of fossil fuel and be capable of selling 25 MW to a utility distribution system to be subject to 40 CFR part 60, subpart TTTT. These applicability provisions exclude industrial EGUs. However, the definition of an EGU also includes "integrated equipment that provides electricity or useful thermal output." This language facilitates the integration of non-emitting generation and avoids energy inputs from non-affected facilities being used in the emission calculation without also considering the emissions of those facilities (*e.g.*, an auxiliary boiler providing steam to a primary boiler). This language could result in certain large processes being included as part of the EGU and meeting the applicability criteria. For example, the high-temperature exhaust from an industrial process (*e.g.*, calcining kilns, dryer, metals processing, or carbon black production facilities) that consumes fossil fuel could be sent to a HRSG to produce electricity. If the industrial process uses more than 250 MMBtu/h heat input and the electric sales exceed the applicability criteria, then the unit could be subject to 40 CFR part 60, subpart TTTT or TTTTa. This is potentially problematic for multiple reasons. First, it is difficult to determine the useful output of the EGU (*i.e.*, HRSG) since part of the useful output is included in the industrial process. In addition, the fossil fuel that is combusted could have a relatively high CO_2 emissions rate on a lb/MMBtu basis, making it potentially problematic to meet the standard of performance using efficient generation. This could result in the owner/operator reducing the electric output of the industrial facility to avoid the applicability criteria. Finally, the compliance costs associated with 40 CFR part 60, subpart TTTT or TTTTa, could discourage the development of environmentally beneficial projects.

To avoid these outcomes, the EPA is, as proposed, amending the applicability provision that exempts EGUs where greater than 50 percent of the heat input is derived from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.[708] Reducing the output or not developing industrial electric generating projects where the majority of the heat input is derived from the industrial process itself would not necessarily result in reductions in GHG emissions from the industrial facility. However, the electricity that would have been produced from the industrial project could still be needed. Therefore, projects of this type provide significant environmental benefit by providing additional useful output with little if any additional environmental impact. Including these types of projects would result in regulatory burden without any associated environmental benefit and could discourage project development,

[708] Auxiliary equipment such as boilers or combustion turbines that provide heat or electricity to the primary EGU (including to any control equipment) would still be considered integrated equipment and included as part of the affected facility.

leading to potential overall increases in GHG emissions.

(B) Industrial EGUs Electric Sales Threshold Permit Requirement

The current electric sales applicability exemption in 40 CFR part 60, subpart TTTT, for non-CHP steam generating units includes the provision that EGUs have "*always been subject to a federally enforceable permit* limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less" (emphasis added). The justification for this restriction includes that the 40 CFR part 60, subpart Da, applicability language includes "constructed for the purpose of . . ." and the Agency concluded that the intent was defined by permit conditions (80 FR 64544; October 23, 2015). This applicability criterion is important both for determining applicability with the new source CAA section 111(b) requirements and for determining whether existing steam generating units are subject to the existing source CAA section 111(d) requirements. For steam generating units that commenced construction after September 18, 1978, the applicability of 40 CFR part 60, subpart Da, would be relatively clear as to what criteria pollutant NSPS is applicable to the facility. However, for steam generating units that commenced construction prior to September 18, 1978, or where the owner/operator determined that criteria pollutant NSPS applicability was not critical to the project (*e.g.,* emission controls were sufficient to comply with either the EGU or industrial boiler criteria pollutant NSPS), owners/operators might not have requested that an electric sales permit restriction be included in the operating permit. Under the current applicability language, some onsite EGUs could be covered by the existing source CAA section 111(d) requirements even if they have never sold electricity to the grid. To avoid covering these industrial EGUs, the EPA proposed and is finalizing amendments to the electric sales exemption in 40 CFR part 60, subparts TTTT and TTTTa, to read, "annual net electric sales *have never exceeded one-third of its potential electric output or 219,000 MWh, whichever is greater, and is* [the "*always been*" would be deleted] subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less" (emphasis added). EGUs that reduce current generation will continue to be covered as long as they sold more than one-third of their potential electric output at some time in the past. The revisions make it possible for an owner/operator of an existing industrial EGU to provide evidence to the Administrator that the facility has never sold electricity in excess of the electricity sales threshold and to modify their permit to limit sales in the future. Without the amendment, owners/operators of any non-CHP industrial EGU capable of selling 25 MW would be subject to the existing source CAA section 111(d) requirements even if they have never sold any electricity. Therefore, the EPA is eliminating the requirement that existing industrial EGUs must have always been subject to a permit restriction limiting net electric sales.

iii. Determination of the Design Efficiency

The design efficiency (*i.e.,* the efficiency of converting thermal energy to useful energy output) of a combustion turbine is used to determine the electric sales applicability threshold. In 40 CFR part 60, subpart TTTT, the sales criteria are based in part on the individual EGU design efficiency. Three methods for determining the design efficiency are currently provided in 40 CFR part 60, subpart TTTT.[709] Since the 2015 NSPS was finalized, the EPA has become aware that owners/operators of certain existing EGUs do not have records of the original design efficiency. These units would not be able to readily determine whether they meet the applicability criteria (and would therefore be subject to CAA section 111(d) requirements for existing sources) in the same way that 111(b) sources would be able to determine if the facility meets the applicability criteria. Many of these EGUs are CHP units that are unlikely to meet the 111(b) applicability criteria and would therefore not be subject to any future 111(d) requirements. However, the language in the 2015 NSPS would require them to conduct additional testing to demonstrate this. The requirement would result in burden to the regulated community without any environmental benefit. The electricity generating market has changed, in some cases dramatically, during the lifetime of existing EGUs, especially concerning ownership. As a result of acquisitions and mergers, original EGU design efficiency documentation, as well as performance guarantee results that affirmed the design efficiency, may no longer exist. Moreover, such documentation and results may not be relevant for current EGU efficiencies, as changes to original EGU configurations, upon which the original design efficiencies were based, render those original design efficiencies moot, meaning that there would be little reason to maintain former design efficiency documentation since it would not comport with the efficiency associated with current EGU configurations. As the three specified methods would rely on documentation from the original EGU configuration performance guarantee testing, and results from that documentation may no longer exist or be relevant, it is appropriate to allow other means to demonstrate EGU design efficiency. To reduce potential future compliance burden, the EPA proposed and is finalizing in 40 CFR part 60, subparts TTTT and TTTTa, to allow alternative methods as approved by the Administrator on a case-by-case basis. Owners/operators of EGUs can petition the Administrator in writing to use an alternate method to determine the design efficiency. The Administrator's discretion is intentionally left broad and can extend to other American Society of Mechanical Engineers (ASME) or International Organization for Standardization (ISO) methods as well as to operating data to demonstrate the design efficiency of the EGU. The EPA also proposed and is finalizing a change to the applicability of paragraph 60.8(b) in table 3 of 40 CFR part 60, subpart TTTT, from "no" to "yes" and that the applicability of paragraph 60.8(b) in table 3 of 40 CFR part 60, subpart TTTTa, is "yes." This allows the Administrator to approve alternatives to the test methods specified in 40 CFR part 60, subparts TTTT and TTTTa.

c. Applicability for 40 CFR Part 60, Subpart TTTTa

This section describes applicability criteria that are only incorporated into 40 CFR part 60, subpart TTTTa, and that differ from the requirements in 40 CFR part 60, subpart TTTT.

Section 111 of the CAA defines a new or modified source for purposes of a given NSPS as any stationary source that commences construction or modification after the publication of the proposed regulation. Thus, the standards of performance apply to EGUs that commence construction or reconstruction after the date of proposal of this rule—May 23, 2023. EGUs that commenced construction after the date

[709] 40 CFR part 60, subpart TTTT, currently lists "ASME PTC 22 Gas Turbines," "ASME PTC 46 Overall Plant Performance," and "ISO 2314 Gas turbines—acceptance tests" as approved methods to determine the design efficiency.

of the proposal for the 2015 NSPS and by May 23, 2023, will remain subject to the standards of performance promulgated in the 2015 NSPS. A modification is any physical change in, or change in the method of operation of, an existing source that increases the amount of any air pollutant emitted to which a standard applies.[710] The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered a new source if it undertakes a reconstruction.[711]

The EPA is finalizing the same applicability requirements in 40 CFR part 60, subpart TTTTa, as the applicability requirements in 40 CFR part 60, subpart TTTT. The stationary combustion turbine must meet the following applicability criteria: The stationary combustion turbine must: (1) be capable of combusting more than 250 MMBtu/h (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.*, for sale to the grid).[712] In addition, the EPA proposed and is finalizing in 40 CFR part 60, subpart TTTTa, to include applicability exemptions for stationary combustion turbines that are: (1) capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less; (2) combined heat and power units subject to a federally enforceable permit condition limiting annual net electric sales to no more than 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater; (3) serving a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity is 25 MW or less; (4) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (5) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (6) deriving greater than 50 percent of heat input from an industrial process that does not produce any electrical or mechanical output that is used outside the affected stationary combustion turbine.

The EPA proposed the same requirements to combustion turbines in non-continental areas (*i.e.*, Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) and non-contiguous areas (non-continental areas and Alaska) as the EPA did for comparable units in the contiguous 48 states.[713] However, the Agency solicited comment on whether owners/operators of new and reconstructed combustion turbines in non-continental and non-contiguous areas should be subject to different requirements. Commenters generally commented that due to the difference in non-contiguous areas relative to the lower 48 states, the proposed requirements should not apply to owners/operators of new or reconstructed combustion turbines in non-contiguous areas. The Agency has considered these comments and is finalizing that only the initial BSER component will be applicable to owners/operators of combustion turbines located in non-contiguous areas. Therefore, owners/operators of base load combustions turbines would not be subject to the CCS-based numerical standards in 2032 and would continue to comply with the efficiency-based numeric standard. Based on information reported in the 2022 EIA Form EIA–860, there are no planned new combustion turbines in either Alaska or Hawaii. In addition, since 2015 no new combustion turbines have commenced operation in Hawaii. Two new combustion turbine facilities totaling 190 MW have commenced operation in Alaska since 2015. One facility is a combined cycle CHP facility and the other is at an industrial facility and neither facility would likely meet the applicability of 40 CFR part 60, subpart TTTTa. Therefore, not finalizing phase-2 BSER for non-continental and non-contiguous areas will have limited, if any, impacts on emissions or costs. The EPA notes that the Agency has the authority to amend this decision in future rulemakings.

i. Applicability to CHP Units

For 40 CFR part 60, subpart TTTT, owners/operators of CHP units calculate net electric sales and net energy output using an approach that includes "at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output." It is unlikely that a CHP unit with a relatively low electric output (*i.e.*, less than 20.0 percent) would meet the applicability criteria. However, if a CHP unit with less than 20.0 percent of the total output consisting of electricity were to meet the applicability criteria, the net electric sales and net energy output would be calculated the same as for a traditional non-CHP EGU. Even so, it is not clear that these CHP units would have less environmental benefit per unit of electricity produced than would more traditional CHP units. For 40 CFR part 60, subpart TTTTa, the EPA proposed and is finalizing to eliminate the restriction that CHP units produce at least 20.0 percent electrical or mechanical output to qualify for the CHP-specific method for calculating net electric sales and net energy output.

In the 2015 NSPS, the EPA did not issue standards of performance for certain types of sources—including industrial CHP units and CHPs that are subject to a federally enforceable permit limiting annual net electric sales to no more than the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh or less, whichever is greater. For CHP units, the approach in 40 CFR part 60, subpart TTTT, for determining net electric sales for applicability purposes allows the owner/operator to subtract the purchased power of the thermal host facility. The intent of the approach is to determine applicability similarly for third-party developers and CHP units owned by the thermal host facility.[714] However, as written in 40 CFR part 60, subpart TTTT, each third-party CHP unit would subtract the entire electricity use of the thermal host facility when determining its net electric sales. It is clearly not the intent of the provision to allow multiple third-party developers that serve the same thermal host to all subtract the purchased power of the thermal host facility when determining net electric sales. This would result in counting the purchased power multiple times. In addition, it is not the intent of the provision to allow a CHP developer to provide a trivial amount of useful thermal output to multiple thermal hosts and then subtract all the thermal hosts' purchased power when determining net electric sales for applicability purposes. The EPA

[710] 40 CFR 60.2.

[711] 40 CFR 60.15(a).

[712] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the "base load rating criterion." Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

[713] 40 CFR part 60, subpart TTTT, also includes coverage for owners/operators of combustion turbines in non-contiguous areas. However, owners/operators of combustion turbines not capable of combusting natural gas (*e.g.*, not connected to a natural gas pipeline) are not subject to the rule. This exemption covers many combustion turbines in non-contiguous areas.

[714] For contractual reasons, many developers of CHP units sell the majority of the generated electricity to the electricity distribution grid. Owners/operators of both the CHP unit and thermal host can subtract the site purchased power when determining net electric sales. Third-party developers that do not own the thermal host can also subtract the purchased power of the thermal host when determining net electric sales for applicability purposes.

proposed and is finalizing in 40 CFR part 60, subpart TTTTa, to limit to the amount of thermal host purchased power that a third-party CHP developer can subtract for electric sales when determining net electric sales equivalent to the percentage of useful thermal output provided to the host facility by the specific CHP unit. This approach eliminates both circumvention of the intended applicability by sales of trivial amounts of useful thermal output and double counting of thermal host-purchased power.

Finally, to avoid potential double counting of electric sales, the EPA proposed and is finalizing that for CHP units determining net electric sales, purchased power of the host facility be determined based on the percentage of thermal power provided to the host facility by the specific CHP facility.

ii. Non-Natural Gas Stationary Combustion Turbines

There is currently an exemption in 40 CFR part 60, subpart TTTT, for stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.*, those that are not connected to a natural gas pipeline). While combustion turbines not connected to a natural gas pipeline meet the general applicability of 40 CFR part 60, subpart TTTT, these units are not subject to any of the requirements. The EPA is not including in 40 CFR part 60, subpart TTTTa, the exemption for stationary combustion turbines that are not physically capable of combusting natural gas. As described in the standards of performance section, owners/operators of combustion turbines burning fuels with a higher heat input emission rate than natural gas would adjust the natural gas-fired emissions rate by the ratio of the heat input-based emission rates. The overall result is that new stationary combustion turbines combusting fuels with higher GHG emissions rates than natural gas on a lb CO_2/MMBtu basis must maintain the same efficiency compared to a natural gas-fired combustion turbine and comply with a standard of performance based on the identified BSER.

2. Subcategorization

In this final rule, the EPA is continuing to include both simple and combined cycle turbines in the definition of a stationary combustion turbine, and like in prior rules for this source category, the Agency is finalizing three subcategories—low load, intermediate load, and base load combustion turbines. These subcategories are determined based on electric sales (*i.e.*, utilization) relative to the combustion turbines' potential electric output to an electric distribution network on both a 12-operating month and 3-year rolling average basis. The applicable subcategory is determined each operating month and a stationary combustion turbine can switch subcategories if the owner/operator changes the way the facility is operated. Subcategorization based on percent electric sales is a proxy for how a combustion turbine operates and for determining the BSER and corresponding emission standards. For example, low load combustion turbines tend to spend a relatively high percentage of operating hours starting and stopping. However, within each subcategory not all combustion turbines operate the same. Some low load combustion turbines operate with less starting and stopping, but in general, combustion turbines tend to operate with fewer starts and stops (*i.e.*, more steady-state hours of operation) with increasing percentages of electric sales. The BSER for each subcategory is based on representative operation of the combustion turbines in that subcategory and on what is achievable for the subcategory as a whole.

Subcategorization by electric sales is similar, but not identical, to subcategorizing by heat input-based capacity factors or annual hours of operation limits.[715] The EPA has determined that, for NSPS purposes, electric sales is appropriate because it reflects operational limitations inherent in the design of certain units, and also that—given these differences—certain emission reduction technologies are more suitable for some units than for others.[716] This subcategorization approach is also consistent with industry practice. For example, operating permits for simple cycle turbines often include annual operating hour limitations of 1,500 to 4,000 hours annually. When average hourly capacity factors (*i.e.*, duty cycles) are accounted for, these hourly restrictions are similar to annual capacity factor restrictions of approximately 15 percent and 40 percent, respectively. The owners or operators of these combustion turbines never intend for them to provide base load power. In contrast, operating permits do not typically restrict the number of hours of annual operation for combined cycle turbines, reflecting that these types of combustion turbines are intended to have the ability to provide base load power.

The EPA evaluated the operation of the three general combustion turbine technologies—combined cycle turbines, frame-type simple cycle turbines, and aeroderivative simple cycle turbines—when determining the subcategorization approach in this rulemaking.[717] The EPA found that, at the same capacity factor, aeroderivative simple cycle turbines have more starts (including fewer operating hours per start) than either frame simple cycle turbines or combined cycle turbines. The maximum number of starts for aeroderivative simple cycle turbines occurs at capacity factors of approximately 30 percent and the maximum number of starts for frame simple cycle turbines and combined cycle turbines both occur at capacity factors of approximately 25 percent. In terms of the median hours of operation per start, the hours per starts increases exponentially with capacity factor for each type of combustion turbine. The rate of increase is greatest for combined cycle turbines with the run times per start increasing significantly at capacity factors of 40 and greater. This threshold roughly matches the subcategorization threshold for intermediate load and base load turbines in this final rule. As is discussed later in section VIII.F.3 and VIII.F.4, technology options including those related to efficiency and to post combustion capture are impacted by the way units operate and can be more effective for units with fewer stops and starts.

a. Legal Basis for Subcategorization

As noted in section V.C.1 of this preamble, CAA section 111(b)(2) provides that the EPA "may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing . . . standards [of performance]." The D.C. Circuit has held that the EPA has broad discretion in determining whether and how to subcategorize under CAA section 111(b)(2). *Lignite Energy Council,* 198 F.3d at 933. As also noted in section V.C.1 of this preamble, in prior CAA section 111 rules, the EPA has subcategorized on numerous bases, including, among other things, fuel type and load, *i.e.*, utilization. In particular, as noted in section V.C.1 of this preamble, the EPA subcategorized on the basis of utilization—for base load

[715] Percent electric sales thresholds, capacity factor thresholds, and annual hours of operation limitations all categorize combustion turbines based on utilization.

[716] While utilization and electric sales are often similar, the EPA uses electric sales because the focus of the applicability is facilities that sell electricity to the grid and not industrial facilities where the electricity is generated primarily for use onsite.

[717] The EPA used manufacturers' designations for frame and aeroderivative combustion turbines.

and non-base load subcategories—in the 2015 NSPS for GHG emissions from combustion turbines, *Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units,* 80 FR 64509 (October 23, 2015), and also in the *NESHAP for Reciprocating Internal Combustion Engines; NSPS for Stationary Internal Combustion Engines,* 79 FR 48072–01 (August 15, 2014).

Subcategorizing combustion turbines based on utilization is appropriate because it recognizes the way differently designed combustion turbines actually operate. Project developers do not construct combined cycle combustion turbine system to start and stop often to serve peak demand. Similarly, project developers do not construct and install simple cycle combustion turbines to operate at higher capacity factors to provide base load demand. And intermediate load demand may be served by higher efficiency simple cycle turbine systems or by ''quick start'' combined cycle units. Thus, there are distinguishing features (*i.e.,* different classes, types, and sizes) of turbines that are predominantly used in each of the utilization-based subcategories. Further, the amount of utilization and the mode of operation are relevant for the systems of emission reduction that the EPA may evaluate to be the BSER and therefore for the resulting standards of performance. See section VII.C.2.a.i for more discussion of the legal basis to subcategorize based upon characteristics relevant to the controls the EPA may determine to be the BSER.

As noted in sections VIII.E.2.b and VIII.F of this preamble, combustion turbines that operate at low load have highly variable operation and therefore highly variable emission rates. This variability made it challenging for the EPA to specify a BSER based on efficient design and operation and limits the BSER for purposes of this rulemaking to lower-emitting fuels. The EPA notes that the subcategorization threshold and the standard of performance are related. For example, the Agency could have finalized a lower electric sales threshold for the low load subcategory (*e.g.,* 15 percent) and evaluated the emission rates at the lower capacity factors. In future rulemaking the Agency could further evaluate the costs and emissions impacts of reducing the threshold for combustion turbines subject to a BSER based on the use of lower emitting fuels.

Intermediate load combustion turbines (*i.e.,* those that operate at loads that are somewhat higher than the low load peaking units) are most often designed to be simple cycle units rather than combined cycle units. This is because combustion turbines operating in the intermediate load range also start and stop and vary their load frequently (though not as often as low load peaking units). Because of the more frequent starts and stops, simple cycle combustion turbines are more economical for project developers when compared to combined cycle combustion turbines. Utilization of CCS technology is not practicable for those simple cycle units due to the lack of a HRSG. Therefore, the EPA has determined that efficient design and operation is the BSER for intermediate load combustion turbines.

While use of CCS is practicable for combined cycle combustion turbines, it is most appropriate for those units that operate at relatively higher loads (*i.e.,* as base load units) that do not frequently start, stop, and change load. Moreover, with current technology, CCS works better on units running at base load levels.

b. Electric Sales Subcategorization (Low, Intermediate, and Base Load Combustion Turbines)

As noted earlier, in the 2015 NSPS, the EPA established separate standards of performance for new and reconstructed natural gas-fired base load and non-base load stationary combustion turbines. The electric sales threshold distinguishing the two subcategories is based on the design efficiency of individual combustion turbines. A combustion turbine qualifies as a non-base load turbine—and is thus subject to a less stringent standard of performance—if it has net electric sales equal to or less than the design efficiency of the turbine (not to exceed 50 percent) multiplied by the potential electric output (80 FR 64601; October 23, 2015). If the net electric sales exceed that level on both a 12-operating month and 3-calendar year basis, then the combustion turbine is in the base load subcategory and is subject to a more stringent standard of performance. Subcategory applicability can change on a month-to-month basis since applicability is determined each operating month. For additional discussion on this approach, see the 2015 NSPS (80 FR 64609–12; October 23, 2015). The 2015 NSPS non-base load subcategory is broad and includes combustion turbines that assure grid reliability by providing electricity during periods of peak electric demand. These peaking turbines tend to have low annual capacity factors and sell a small amount of their potential electric output. The non-base load subcategory in the 2015 NSPS also includes combustion turbines that operate at intermediate annual capacity factors and are not considered base load EGUs. These intermediate load EGUs provide a variety of services, including providing dispatchable power to support variable generation from renewable sources of electricity. The need for this service has been expanding as the amount of electricity from wind and solar continues to grow. In the 2015 NSPS, the EPA determined the BSER for the non-base load subcategory to be the use of lower-emitting fuels (*e.g.,* natural gas and Nos. 1 and 2 fuel oils). In 2015, the EPA explained that efficient generation did not qualify as the BSER due in part to the challenge of determining an achievable output-based CO_2 emissions rate for all combustion turbines in this subcategory.

In this action, the EPA proposed and is finalizing the subcategories in 40 CFR part 60, subpart TTTTa, that will be applicable to sources that commence construction or reconstruction after May 23, 2023. First, the Agency proposed and is finalizing the definition of design efficiency so that the heat input calculation of an EGU is based on the higher heating value (HHV) of the fuel instead of the lower heating value (LHV), as explained immediately below. This has the effect of lowering the calculated potential electric output and the electric sales threshold. In addition, the EPA proposed and is finalizing division of the non-base load subcategory into separate intermediate and low load subcategories.

i. Higher Heating Value as the Basis for Calculation of the Design Efficiency

The *heat rate* is the amount of energy used by an EGU to generate 1 kWh of electricity and is often provided in units of Btu/kWh. As the thermal efficiency of a combustion turbine EGU is increased, less fuel is burned per kWh generated and there is a corresponding decrease in emissions of CO_2 and other air pollutants. The electric energy output as a fraction of the fuel energy input expressed as a percentage is a common practice for reporting the unit's efficiency. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process. Lower heat rates are associated with more efficient power generating plants.

Efficiency can be calculated using the HHV or the LHV of the fuel. The HHV is the heating value directly determined by calorimetric measurement of the fuel in the laboratory. The LHV is calculated using a formula to account for the moisture in the combustion gas (*i.e.*, subtracting the energy required to vaporize the water in the flue gas) and is a lower value than the HHV. Consequently, the HHV efficiency for a given EGU is always lower than the corresponding LHV efficiency because the reported heat input for the HHV is larger. For U.S. pipeline natural gas, the HHV heating value is approximately 10 percent higher than the corresponding LHV heating value and varies slightly based on the actual constituent composition of the natural gas.[718] The EPA default is to reference all technologies on a HHV basis,[719] and the Agency is basing the heat input calculation of an EGU on HHV for purposes of the definition of design efficiency. However, it should be recognized that manufacturers of combustion turbines typically use the LHV to express the efficiency of combustion turbines.[720]

Similarly, the electric energy output for an EGU can be expressed as either of two measured values. One value relates to the amount of total electric power generated by the EGU, or *gross* output. However, a portion of this electricity must be used by the EGU facility to operate the unit, including compressors, pumps, fans, electric motors, and pollution control equipment. This within-facility electrical demand, often referred to as the parasitic load or auxiliary load, reduces the amount of power that can be delivered to the transmission grid for distribution and sale to customers. Consequently, electric energy output may also be expressed in terms of *net* output, which reflects the EGU gross output minus its parasitic load.[721]

When using efficiency to compare the effectiveness of different combustion turbine EGU configurations and the applicable GHG emissions control technologies, it is important to ensure that all efficiencies are calculated using the same type of heating value (*i.e.*, HHV or LHV) and the same basis of electric energy output (*i.e.*, MWh-gross or MWh-net). Most emissions data are available on a gross output basis and the EPA is finalizing output-based standards based on gross output. However, to recognize the superior environmental benefit of minimizing auxiliary/parasitic loads, the Agency is including optional equivalent standards on a net output basis. To convert from gross to net output-based standards, the EPA used a 2 percent auxiliary load for simple and combined cycle turbines and a 7 percent auxiliary load for combined cycle EGUs using 90 percent CCS.[722]

ii. Lowering the Threshold Between the Base Load and Non-Base Load Subcategories

The subpart TTTT distinction between a base load and non-base load combustion turbine is determined by the unit's actual electric sales relative to its potential electric sales, assuming the EGU is operated continuously (*i.e.*, percent electric sales). Specifically, stationary combustion turbines are categorized as non-base load and are subsequently subject to a less stringent standard of performance if they have net electric sales equal to or less than their design efficiency (not to exceed 50 percent) multiplied by their potential electric output (80 FR 64601; October 23, 2015). Because the electric sales threshold is based in part on the design efficiency of the EGU, more efficient combustion turbine EGUs can sell a higher percentage of their potential electric output while remaining in the non-base load subcategory. This approach recognizes both the environmental benefit of combustion turbines with higher design efficiencies and provides flexibility to the regulated community. In the 2015 NSPS, it was unclear how often high-efficiency simple cycle EGUs would be called upon to support increased generation from variable renewable generating resources. Therefore, the Agency determined it was appropriate to provide maximum flexibility to the regulated community. To do this, the Agency based the numeric value of the design efficiency, which is used to calculate the electric sales threshold, on the LHV efficiency. This had the impact of allowing combustion turbines to sell a greater share of their potential electric output while remaining in the non-base load subcategory.

The EPA proposed and is finalizing that the design efficiency in 40 CFR part 60, subpart TTTTa be based on the HHV efficiency instead of LHV efficiency and to not include the 50 percent maximum and 33 percent minimum restrictions. When determining the potential electric output used in calculating the electric sales threshold in 40 CFR part 60, subpart TTTT, design efficiencies of greater than 50 percent are reduced to 50 percent and design efficiencies of less than 33 percent are increased to 33 percent for determining electric sales threshold subcategorization criteria. The 50 percent criterion was established to limit non-base load EGUs from selling greater than 55 percent of their potential electric sales.[723] The 33 percent criterion was included to be consistent with applicability thresholds in the electric utility criteria pollutant NSPS (40 CFR part 60, subpart Da).

Neither of those criteria are appropriate for 40 CFR part 60, subpart TTTTa, and the EPA proposed and is finalizing a decision that they are not incorporated when determining the electric sales threshold. Instead, as discussed later in the section, the EPA is finalizing a fixed percent electric sales thresholds and the design efficiency does not impact the subcategorization thresholds. However, the design efficiency is still used when determining the potential electric sales and any restriction on using the actual design efficiency of the combustion turbine would have the impact of changing the threshold. If this restriction were maintained, it would reduce the regulatory incentive for manufacturers to invest in programs to develop higher efficiency combustion turbines.

The EPA also proposed and is finalizing a decision to eliminate the 33 percent minimum design efficiency in the calculation of the potential electric output. The EPA is unaware of any new combustion turbines with design efficiencies meeting the general

[718] The HHV of natural gas is 1.108 times the LHV of natural gas. Therefore, the HHV efficiency is equal to the LHV efficiency divided by 1.108. For example, an EGU with a LHV efficiency of 59.4 percent is equal to a HHV efficiency of 53.6 percent. The HHV/LHV ratio is dependent on the composition of the natural gas (*i.e.*, the percentage of each chemical species (*e.g.*, methane, ethane, propane)) within the pipeline and will slightly move the ratio.

[719] Natural gas is also sold on a HHV basis.

[720] European plants tend to report thermal efficiency based on the LHV of the fuel rather than the HHV for both combustion turbines and steam generating EGUs. In the U.S., boiler efficiency is typically reported on a HHV basis.

[721] It is important to note that net output values reflect the net output delivered to the electric grid and not the net output delivered to the end user. Electricity is lost as it is transmitted from the point of generation to the end user and these "line losses" increase the farther the power is transmitted. 40 CFR part 60, subpart TTTT, provides a way to account for the environmental benefit of reduced line losses by crediting CHP EGUs, which are typically located close to large electric load centers. See 40 CFR 60.5540(a)(5)(i) and the definitions of gross energy output and net energy output in 40 CFR 60.5580.

[722] The 7 percent auxiliary load for combined cycle turbines with 90 percent CCS is specific to electric output. Additional auxiliary load includes thermal energy that is diverted to the CCS system instead of being used to generate additional electricity. This additional auxiliary thermal energy is accounted for when converting the phase 1 emissions standard to the phase 2 standard.

[723] While the design efficiency is capped at 50 percent on a LHV basis, the base load rating (maximum heat input of the combustion turbine) is on a HHV basis. This mixture of LHV and HHV results in the electric sales threshold being 11 percent higher than the design efficiency. The design efficiency of all new combined cycle EGUs exceed 50 percent on a LHV basis.

applicability criteria of less than 33 percent; and this will likely have no cost or emissions impact.

The EPA solicited comment on whether the intermediate/base load electric sales threshold should be reduced further to a range that would lower the base load electric sales threshold for simple cycle turbines to between 29 to 35 percent (depending on the design efficiency) and to between 40 to 49 percent for combined cycle turbines (depending on the design efficiency). The specific approach the EPA solicited comment on was reducing the design efficiency by 6 percent (*e.g.,* multiplying by 0.94) when determining the electric sales threshold. Some commenters supported lowering the proposed electric sales threshold while others supported maintaining the proposed standards.

After considering comments, in 40 CFR part 60, subpart TTTTa, the EPA has determined it is appropriate to eliminate the sliding scale electric sales threshold based on the design efficiency and instead base the subcategorization thresholds on fixed electric sales (also referred to sometimes here as capacity factor). In 40 CFR part 60 subpart TTTTa, the EPA is finalizing that the fixed electric sales threshold between intermediate load combustion turbines and base load combustion turbines is 40 percent. The 40 percent electric sales (capacity factor) threshold reflects the maximum capacity factor for intermediate load simple cycle turbines and the minimum prorated efficiency approach for base load combined cycle turbines that the EPA solicited comment on in proposal.[724]

The base load electric sales threshold is appropriate for new combustion turbines because, as will be discussed later, the first component of BSER for base load turbines is based on highly efficient combined cycle generation. Combined cycle units are significantly more efficient than simple cycle turbines; and therefore, in general, the EPA should be focusing its determination of the BSER for base load units on that more efficient technology. The electric sales thresholds and the emission standards are related because, at lower capacity factors, combustion turbines tend to have more variable operation (*e.g.,* more starts and stops and operation at part load conditions) that reduces the efficiency of the combustion turbine. This is particularly the case for combined cycle turbines because while the turbine engine can come to full load relatively quickly, the HRSG and steam turbine cannot, and combined cycle turbines responding to highly variable load will have efficiencies similar to simple cycle turbines.[725] This has implications for the appropriate control technologies and corresponding emission reduction potential. The EPA determined the final standard of performance based on review of emissions data for recently installed combined cycle combustion turbines with 12-operating month capacity factors of 40 percent or greater. The EPA considered a capacity factor threshold lower than 40 percent. However, expanding the subcategory to include combustion turbines with a 12-operating month electric sales of less than 40 percent would require the EPA to consider the emissions performance of combined cycle turbines operating at lower capacity factors and, while it would expand the number of sources in the base load subcategory, it would also result in a higher (*i.e.,* less stringent) numerical emission standard for the sources in the category.

Direct comparison of the costs of combined cycle turbines relative to simple cycle turbines can be challenging because model plant costs are often for combustion turbines of different sizes and do not account for variable operation. For example, combined cycle turbine model plants are generally for an EGU that is several hundred megawatts while simple cycle turbine model plants are generally less than a hundred megawatts. Direct comparison of the LCOE from these model plants is not relevant because the facilities are not comparable. Consider a facility with a block of 10 simple cycle turbines that are each 50 MW (so the overall facility capacity is 500 MW). Each simple cycle turbine operates as an individual unit and provides a different value to the electric grid as compared to a single 500 MW combined cycle turbine. While the minimum load of the combined cycle facility might be 200 MW, the block of 10 simple cycle turbines can provide from approximately 20 MW to 500 MW to the electric grid.

A more accurate cost comparison accounts for economies of scale and estimates the cost of a combined cycle turbine with the same net output as a simple cycle turbine. Comparing the modeled LCOE of these combustion turbines provides a meaningful comparison, at least for base load combustion turbines. Without accounting for economies of scale and variable operation, combined cycle turbines can appear to be more cost effective than simple cycle turbines under almost all conditions. In addition, without accounting for economies of scale, large frame simple cycle turbines can appear to be more cost effective than higher efficiency aeroderivative simple cycle turbines, even if operated at a 100 percent capacity factor. These cost models are not intended to make direct comparisons, and the EPA appropriately accounted for economies of scale when estimating the cost of the BSER. Since base load combustion turbines tend to operate under steady state conditions with few starts and stops, startup and shutdown costs and the efficiency impact of operating at variable loads are not important for determining the compliance costs of base load combustion turbines.

Based on an adjusted model plant comparison, combined cycle EGUs have a lower LCOE at capacity factors above approximately 40 percent compared to simple cycle EGUs operating at the same capacity factors. This supports the final base load fixed electric sales threshold of 40 percent for simple cycle turbines because it would be cost-effective for owners/operators of simple cycle turbines to add heat recovery if they elected to operate at higher capacity factors as a base load unit. Furthermore, based on an analysis of monthly emission rates, recently constructed combined cycle EGUs maintain consistent emission rates at capacity factors of less than 55 percent (which is the base load electric sales threshold in subpart TTTT) relative to operation at higher capacity factors. Therefore, the base load subcategory operating range can be expanded in 40 CFR part 60, subpart TTTTa, without impacting the stringency of the numeric standard. However, at capacity factors of less than approximately 40 percent, emission rates of combined cycle EGUs increase relative to their operation at higher capacity factors. It takes much longer for a HRSG to begin producing steam that can be used to generate additional electricity than it takes a combustion engine to reach full power. Under operating conditions with a significant number of starts and stops, typical of some intermediate and especially low load combustion turbines, there may not be enough time for the HRSG to generate steam that can be used for additional electrical generation. To maximize overall efficiency, combined cycle EGUs often use combustion turbine engines that are less efficient than the most

[724] The EPA solicited comment on basing the electric sales threshold on a value calculated using 0.94 times the design efficiency.

[725] This discussion assumes that the combined cycle turbine incorporates a bypass stack that allows the combustion turbine engine to operate independent of the HRSG/steam turbine. Without a bypass stack the combustion turbine engine could not come to full load as quickly.

efficient simple cycle turbine engines. Under operating conditions with frequent starts and stops where the HRSG does not have sufficient time to begin generating additional electricity, a combined cycle EGU may be no more efficient than a highly efficient simple cycle EGU. These distinctions in operation are thus meaningful for determining which emissions control technologies are most appropriate for types of units. Once a combustion turbine unit exceeds approximately 40 percent annual capacity factor, it is economical to add a HRSG which results in the unit becoming both more efficient and less likely to cycle its operation. Such units are, therefore, better suited for more stringent emission control technologies including CCS.

After the 2015 NSPS was finalized, some stakeholders expressed concerns about the approach for distinguishing between base load and non-base load turbines. They posited a scenario in which increased utilization of wind and solar resources, combined with low natural gas prices, would create the need for certain types of simple cycle turbines to operate for longer time periods than had been contemplated when the 2015 NSPS was being developed. Specifically, stakeholders have claimed that in some regional electricity markets with large amounts of variable renewable generation, some of the most efficient new simple cycle turbines—aeroderivative turbines—could be called upon to operate at capacity factors greater than their design efficiency. However, if those new simple cycle turbines were to operate at those higher capacity factors, they would become subject to the more stringent standard of performance for base load turbines. As a result, according to these stakeholders, the new aeroderivative turbines would have to curtail their generation and instead, less-efficient existing turbines would be called upon to run by the regional grid operators, which would result in overall higher emissions. The EPA evaluated the operation of simple cycle turbines in areas of the country with relatively large amounts of variable renewable generation and did not find a strong correlation between the percentage of generation from the renewable sources and the 12-operating month capacity factors of simple cycle turbines. In addition, most of the simple cycle turbines that commenced operation between 2010 and 2016 (the most recent simple cycle turbines not subject to 40 CFR part 60, subpart TTTT) have operated well below the base load electric sales threshold in 40 CFR part 60, subpart TTTT. Therefore, the Agency does not believe that the concerns expressed by stakeholders necessitates any revisions to the regulatory scheme. In fact, as noted above, the EPA is finalizing that the electric sales threshold can be lowered without impairing the availability of simple cycle turbines where needed, including to support the integration of variable generation. The EPA believes that the final threshold is not overly restrictive since a simple cycle turbine could operate on average for more than 9 hours a day in the intermediate load subcategory.

iii. Low and Intermediate Load Subcategories

This section discusses the EPA's rationale for subcategorizing non-base load combustion turbines into two subcategories—low load and intermediate load.

(A) Low Load Subcategory

The EPA proposed and is finalizing in 40 CFR part 60, subpart TTTTa, a low load subcategory to includes combustion turbines that operate only during periods of peak electric demand (*i.e.,* peaking units), which will be separate from the intermediate load subcategory. Low load combustion turbines also provide ramping capability and other ancillary services to support grid reliability. The EPA evaluated the operation of recently constructed simple cycle turbines to understand how they operate and to determine at what electric sales level or capacity factor their emissions rate is relatively steady. (Note that for purposes of this discussion, the terms ''electric sales'' and ''capacity factor'' are used interchangeably.) Low load combustion turbines generally only operate for short periods of time and potentially at relatively low duty cycles.[726] This type of operation reduces the efficiency and increases the emissions rate, regardless of the design efficiency of the combustion turbine or how it is maintained. For this reason, it is difficult to establish a reasonable output-based standard of performance for low load combustion turbines.

To determine the electric sales threshold—that is, to distinguish between the intermediate load and low load subcategories—the EPA evaluated capacity factor electric sales thresholds of 10 percent, 15 percent, 20 percent, and 25 percent. The EPA proposed to find and is finalizing a conclusion that the 10 percent threshold is problematic for two reasons. First, simple cycle turbines operating at that level or lower have highly variable emission rates, and therefore it is difficult for the EPA to establish a meaningful output-based standard of performance. In addition, only one-third of simple cycle turbines that have commenced operation since 2015 have maintained 12-operating month capacity factors of less than 10 percent. Therefore, setting the threshold at this level would bring most new simple cycle turbines into the intermediate load subcategory, which would subject them to a more stringent emission rate that is only achievable for simple cycle turbines operating at higher capacity factors. This could create a situation where simple cycle turbines might not be able to comply with the intermediate load standard of performance while operating at the low end of the intermediate load capacity factor subcategorization criteria.

Based on the EPA's review of hourly emissions data, at a capacity factor above 15 percent, GHG emission rates for many simple cycle turbines begin to stabilize. At higher capacity factors, more time is typically spent at steady state operation rather than ramping up and down; and emission rates tend to be lower while in steady-state operation. Of recently constructed simple cycle turbines, half have maintained 12-operating month capacity factors of 15 percent or less, two-thirds have maintained capacity factors of 20 percent or less; and approximately 80 percent have maintained maximum capacity factors of 25 percent or less. The emission rates clearly stabilize for most simple cycle turbines operating at capacity factors of greater than 20 percent. Based on this information, the EPA proposed the low load electric sales threshold—again, the dividing line to distinguish between the intermediate and low load subcategories—to be 20 percent and solicited comment on a range of 15 to 25 percent. The EPA also solicited comment on whether the low load electric sales threshold should be determined by a site-specific threshold based on three-fourths of the design efficiency of the combustion turbine.[727]Under this approach, simple

[726] The duty cycle is the average operating capacity factor. For example, if an EGU operates at 75 percent of the fully rated capacity, the duty cycle would be 75 percent regardless of how often the EGU actually operates. The capacity factor is a measure of how much an EGU is operated relative to how much it could potentially have been operated.

[727] The calculation used to determine the electric sales threshold includes both the design efficiency and the base load rating. Since the base load rating stays the same when adjusting the numeric value of the design efficiency for applicability purposes, adjustments to the design efficiency has twice the impact. Specifically, using three-fourths of the

cycle turbines selling less than 18 to 22 percent of their potential electric output (depending on the design efficiency) would still have been considered low load combustion turbines. This ''sliding scale'' electric sales threshold approach is like the approach the EPA used in the 2015 NSPS to recognize the environmental benefit of installing the most efficient combustion turbines for low load applications. Using this approach, combined cycle EGUs would have been able to sell between 26 to 31 percent of their potential electric output while still being considered low load combustion turbines. Some commenters supported a lower electric sales threshold while others supported a higher threshold. Based on these comments, the EPA is finalizing the proposed low load electric sales threshold of 20 percent of the potential electric sales. The fixed 20 percent capacity factor threshold represents a level of utilization at which most simple cycle combustion turbines perform at a consistent level of efficiency and GHG emission performance, enabling the EPA to establish a standard of performance that reflects a BSER of efficient operation. The 20 percent capacity factor threshold is also more environmentally protective than the higher thresholds the EPA considered, since owners and operators of combustion turbines operating above a 20 percent capacity factor would be subject to an output-based emissions standard instead of a heat input-based emissions standard based on the use of lower-emitting fuels. This ensures that owners/operators of intermediate load combined cycle turbines properly maintain and operate their combustion turbines.

(B) Intermediate Load Subcategory

The proposed sliding scale subcategorization approach essentially included two subcategories within the proposed intermediate load subcategory. As proposed, simple cycle turbines would be classified as intermediate load combustion turbines when operated between capacity factors of 20 percent and approximately 40 percent while combined cycle turbines would be classified as intermediate load combustion turbines when operated between capacity factors of 20 percent to approximately 55 percent. Owners/operators of combined cycle turbines operating at the high end of the intermediate load subcategory would only be subject to an emissions standard based on a BSER of high-efficiency simple cycle turbine technology. The proposed approach provided a regulatory incentive for owners/operators to purchase the most efficient technologies in exchange for additional compliance flexibility. The use of a prorated efficiency the EPA solicited comment on would have lowered the simple cycle and combined cycle turbine thresholds to approximately 35 percent and 50 percent, respectively.

In this final rule, the BSER for the intermediate load subcategory is consistent with the proposal—high-efficiency simple cycle turbine technology. While not specifically identified in the proposal, the BSER for the base load subcategory is also consistent with the proposal—the use of combined cycle technology.[728]

The 12-operating month electric sales (*i.e.*, capacity factor) thresholds for the stationary combustion turbine subcategories in this final rule are summarized below in Table 2.

TABLE 2—SALES THRESHOLDS FOR SUBCATEGORIES OF COMBUSTION TURBINE EGUS

Subcategory	12-Operating month electric sales threshold (percent of potential electric sales)
Low Load	≤20
Intermediate Load	>20 and ≤40
Base Load	>40

iv. Integrated Onsite Generation and Energy Storage

Integrated equipment is currently included as part of the affected facility, and the EPA proposed and is finalizing amended regulatory text to clarify that the output from integrated renewables is included as output when determining the NSPS emissions rate. The EPA also proposed that the output from the integrated renewable generation is not included when determining the net electric sales for applicability purposes (*i.e.*, generation from integrated renewables would not be considered when determining if a combustion turbine is subcategorized as a low, intermediate, or base load combustion turbine). In the alternative, the EPA solicited comment on whether instead of exempting the generation from the integrated renewables from counting toward electric sales, the potential output from the integrated renewables would be included when determining the design efficiency of the facility. Since the design efficiency is used when determining the electric sales threshold this would increase the allowable electric sales for subcategorization purposes. Including the integrated renewables when determining the design efficiency of the affected facility has the impact of increasing the operational flexibility of owners/operators of combustion turbines. Commenters generally supported maintaining that integrated renewables are part of the affected facility and including the output of the renewables when determining the emissions rate of the affected facility.[729] Therefore, the Agency is finalizing a decision that the rated output of integrated renewables be included when determining the design efficiency of the affected facility, which is used to determine the potential electric output of the affected facility, and that the output of the integrated renewables be included in determining the emissions rate of the affected facility. However, since the design efficiency is not a factor in determining the subcategory thresholds in 40 CFR part 60, subpart TTTTa, the output of the integrated renewables will not be included for determining the applicable subcategory. If the output from the integrated renewable generation were included for subcategorization purposes, this could discourage the use of integrated renewables (or curtailments) because affected facilities could move to a subcategory with a more stringent emissions standard that could cause the owner/operator to be out of compliance. The impact of this approach is that the electric sales threshold of the combustion turbine island itself, not including the integrated renewables, for an owner/operator of a combustion turbine that includes integrated renewables that increase the potential electric output by 1 percent would be 1 or 2 percent higher for the stationary combustion turbine island not considering the integrated renewables, depending on the design efficiency of the combustion turbine itself, than an identical combustion turbine without integrated renewables. In addition, when the output from the integrated renewables is considered, the output from the integrated renewables

design efficiency reduces the electric sales threshold by half.

[728] Under the proposed subcategorization approach, for a combustion turbine to be subcategorized as an intermediate load combustion turbine while operating at capacity factors of greater than 40 percent required the use of a HRSG (*e.g.*, combined cycle turbine technology).

[729] The EPA did not propose to include, and is not finalizing including, integrated renewables as part of the BSER. Commenters opposed a BSER that would include integrated renewables as part of the BSER. Commenters noted that this could result in renewables being installed in suboptimal locations which could result in lower overall GHG reductions.

lowers the emissions rate of the affected facility by approximately 1 percent.

For integrated energy storage technologies, the EPA solicited comment on and is finalizing a decision to include the rated output of the energy storage when determining the design efficiency of the affected facility. Similar to integrated renewables, this increases the flexibility of owner/operators to sell larger amounts of electricity while remaining in the low, variable, and intermediate load subcategories. While energy storage technologies have high capital costs, operating costs are low and would dispatch prior to the combustion turbine the technology is integrated with. Therefore, simple cycle turbines with integrated energy storage would likely operate at lower capacity factors than an identical simple cycle turbine at the same location. However, while the energy storage might be charged with renewables that would otherwise be curtailed, there is no guarantee that low emitting generation would be used to charge the energy storage. Therefore, the output from the energy storage is not considered in either determining the NSPS emissions rate or as net electric sales for subcategorization applicability purposes. In future rulemaking the Agency could further evaluate the impact of integrated energy storage on the operation of simple cycle turbines to determine if the number of starts and stops are reduced and increases the efficiency of simple cycle turbines relative to simple cycle turbines without integrated energy storage. If this is the case, it could be appropriate to lower the threshold for combustion turbines subject to a lower emitting fuels BSER because emission rates would be stable at lower capacity factors.

v. Definition of System Emergency

In 2015, the EPA included a provision that electricity sold during hours of operation when a unit is called upon due to a system emergency is not counted toward the percentage electric sales subcategorization threshold in 40 CFR part 60, subpart TTTT.[730] The Agency concluded that this exclusion is necessary to provide flexibility, maintain system reliability, and minimize overall costs to the sector.[731] The intent is that the local grid operator will determine the EGUs essential to maintaining grid reliability. Subsequent to the 2015 NSPS, members of the regulated community informed the EPA that additional clarification of a system emergency is needed to determine and document generation during system emergencies. The EPA proposed to include the system emergency approach in 40 CFR part 60, subpart TTTTa, and solicited comment on amending the definition of system emergency to clarify in implementation in 40 CFR part 60, subparts TTTT and TTTTa. Commenters generally agreed with the proposal to allow owners/operators of EGUs called upon during a system emergency to operate without impacting the EGUs' subcategorization (*i.e.*, electric sales during system emergencies would not be considered when determining net electric sales), and that the Agency should clarify how system emergencies are determined and documented.

In terms of the definition of the system emergency provision, commenters stated that ''abnormal'' be deleted from the definition, and instead of referencing ''the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator,'' the definition should reference ''the balancing authority or reliability coordinator.'' This change would align the regulation's definition with the terms used by NERC. Some commenters also stated that the EPA should specify that electric sales during periods the grid operator declares energy emergency alerts (EEA) levels 1 through 3 be included in the definition of system emergency.[732] In addition, some commenters stated that the definition should be expanded to include the concept of energy emergencies. Specifically, the definition should also exempt generation during periods when a load-serving entity or balancing authority has exhausted all other resource options and can no longer meet its expected load obligations. Finally, commenters stated that the definition should apply to all EGUs, regardless of if they are already operating when the system emergency is declared. This would avoid regulatory incentive to come offline prior to a potential system emergency to be eligible for the electric sales exemption and would treat all EGUs similarly during system emergencies (*i.e.*, not penalize EGUs that are already operating to maintain grid reliability and avoiding the need to declare grid emergencies).

The Agency is including the system emergency concept in 40 CFR part 60, subpart TTTTa, along with a definition that clarifies how to determine generation during periods of system emergencies. The EPA agrees with commenters that the definition of system emergency should be clarified and that it should not be limited to EGUs not operating when the system emergency is declared. Based on information provided by entities with reliability expertise, the EPA has determined that a system emergency should be defined to include EEA levels 2 and 3. These EEA levels generally correspond to time-limited, well-defined, and relatively infrequent situations in which the system is experiencing an energy deficiency. During EEA level 2 and 3 events, all available generation is online and demand-response or other load management procedures are in effect, or firm load interruption is imminent or in progress. The EPA believes it is appropriate to exclude hours of operation during such events in order to ensure that EGUs are not impeded from maintaining or increasing their output as needed to respond to a declared energy emergency. Because these events tend to be short, infrequent, and well-defined, the EPA also believes any incremental GHG emissions associated with operations during these periods would be relatively limited.

The EPA has determined not to include EEA level 1 in the definition of a ''system emergency.'' The EPA's understanding is that EEA level 1 events often include situations in which an energy deficiency does not yet exist, and in which balancing authorities are preparing to pursue various options for either bringing additional resources online or managing load. The EPA also understands that EEA level 1 events tend to be more frequently declared, and longer in duration, than level 2 or 3 events. Based on this information, the EPA believes that including EEA level 1 events in the definition of a ''system emergency'' would carry a greater risk of increasing overall GHG emissions without making a meaningful contribution to supporting reliability. This approach balances the need to have operational flexibility when the grid may be strained to help ensure that all available generating sources are available for grid reliability, while balancing with important considerations about potential GHG emission tradeoffs. The EPA is also amending the definition in 40 CFR part 60, subpart TTTT, to be

[730] In 40 CFR part 60, subpart TTTT, electricity sold by units that are not called upon to operate due to a system emergency (*e.g.*, units already operating when the system emergency is declared) is counted toward the percentage electric sales threshold.

[731] See 80 FR 64612; October 23, 2015.

[732] Commenters noted that grid operators have slightly different terms for grid emergencies, but example descriptions include: EEA 1, all available generation online and non-firm wholesale sales curtailed; EEA 2, load management procedures in effect, all available generation units online, demand-response programs in effect; and EEA 3, firm load interruption is imminent or in progress.

consistent with the definition in 40 CFR part 60, subpart TTTTa.

Commenters also added that operation during system emergencies should be subject to alternate standards of performance (*e.g.*, owners/operators are not required to use the CCS system during system emergencies to increase power output). The EPA agrees with commenters that since system emergencies are defined and historically rare events, an alternate standard of performance should apply during these periods. Carbon capture systems require significant amounts of energy to operate. Allowing owners/operators of EGUs equipped with CCS systems to temporarily reduce the capture rate or cease capture will increase the electricity available to end users during system emergencies. In place of the applicable output-based emissions standard, the owner/operator of an intermediate or base load combustion turbine would be subject to a BSER based on the combustion of lower-emitting fuels during system emergencies.[733] The emissions and output would not be included when calculating the 12-operating month emissions rate. The EPA considered an alternate emissions standard based on efficient generation but rejected that for multiple reasons. First, since system emergencies are limited in nature the emissions calculation would include a limited number of hours and would not necessarily be representative of an achievable longer-term emissions rate. In addition, EGUs that are designed to operate with CCS will not necessarily operate as efficiently without the CCS system operating compared to a similar EGU without a CCS system. Therefore, the Agency is not able to determine a reasonable efficiency-based alternate emissions standard for periods of system emergencies. Due to both the costs and time associated with starting and stopping the CCS system, the Agency has determined it is unlikely that an owner/operator of an affected facility would use it where it is not needed. System emergencies have historically been relatively brief and any hours of operation outside of the system emergencies are included when determining the output-based emissions standard. During short-duration system emergencies, the costs associated with stopping and starting the CCS system could outweigh the increased revenue from the additional electric sales. In addition, the time associated with starting and stopping a CCS system would likely result in an EGU operating without the CCS system in operation during periods of non-system emergencies. This would require the owner/operator to overcontrol during other periods of operation to maintain emissions below the applicable standard of performance. Therefore, it is likely an owner/operator would unnecessarily adjust the operation of the CCS system during EEA levels 2 and 3.

In addition to these measures, DOE has authority pursuant to section 202(c) of the Federal Power Act to, on its own motion or by request, order, among other things, the temporary generation of electricity from particular sources in certain emergency conditions, including during events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements. Such orders may be issued for 90 days and may be extended in 90-day increments after consultation with the EPA. DOE has historically issued section 202(c) orders at the request of electric generators and grid operators such as RTOs in order to enable the supply of additional generation in times of expected emergency-related generation shortfalls.

c. Multi-Fuel-Fired Combustion Turbines

In 40 CFR part 60, subpart TTTT, multi-fuel-fired combustion turbines are subcategorized as EGUs that combust 10 percent or more of fuels not meeting the definition of natural gas on a 12-operating month rolling average basis. The BSER for this subcategory is the use of lower-emitting fuels with a corresponding heat input-based standard of performance of 120 to 160 lb CO_2/MMBtu, depending on the fuel, for newly constructed and reconstructed multi-fuel-fired stationary combustion turbines.[734] Lower-emitting fuels for these units include natural gas, ethylene, propane, naphtha, jet fuel kerosene, Nos. 1 and 2 fuel oils, biodiesel, and landfill gas. The definition of natural gas in 40 CFR part 60, subpart TTTT, includes fuel that maintains a gaseous state at ISO conditions, is composed of 70 percent by volume or more methane, and has a heating value of between 35 and 41 megajoules (MJ) per dry standard cubic meter (dscm) (950 and 1,100 Btu per dry standard cubic foot). Natural gas typically contains 95 percent methane and has a heating value of 1,050 Btu/lb.[735] A potential issue with the multi-fuel subcategory is that owners/operators of simple cycle turbines can elect to burn 10 percent non-natural gas fuels, such as Nos. 1 or 2 fuel oil, and thereby remain in that subcategory, regardless of their electric sales. As a result, they would remain subject to the less stringent standard that applies to multi-fuel-fired sources, the lower-emitting fuels standard. This could allow less efficient combustion turbine designs to operate as base load units without having to improve efficiency and could allow EGUs to avoid the need for efficient design or best operating and maintenance practices. These potential circumventions would result in higher GHG emissions.

To avoid these outcomes, the EPA proposed and is finalizing a decision not to include the multi-fuel subcategory for low, intermediate, and base load combustion turbines in 40 CFR part 60, subpart TTTTa. This means that new multi-fuel-fired turbines that commence construction or reconstruction after May 23, 2023, will fall within a particular subcategory depending on their level of electric sales. The EPA also proposed and is finalizing a decision that the performance standards for each subcategory be adjusted appropriately for multi-fuel-fired turbines to reflect the application of the BSER for the subcategories to turbines burning fuels with higher GHG emission rates than natural gas. To be consistent with the definition of lower-emitting fuels in the 2015 NSPS, the maximum allowable heat input-based emissions rate is 160 lb CO_2/MMBtu. For example, a standard of performance based on efficient generation would be 33 percent higher for a fuel oil-fired combustion turbine compared to a natural gas-fired combustion turbine. This assures that the BSER, in this case efficient generation, is applied, while at the same time accounting for the use of multiple fuels.

[733] For owners/operators of combustion turbines the lower emitting fuels requirement is defined to include fuels with an emissions rate of 160 lb CO_2/MMBtu or less. For owners/operators of steam generating units or IGCC facilities the EPA is requiring the use of the maximum amount of non-coal fuels available to the affected facility.

[734] Combustion turbines co-firing natural gas with other fuels must determine fuel-based site-specific standards at the end of each operating month. The site-specific standards depend on the amount of co-fired natural gas. 80 FR 64616 (October 23, 2015).

[735] Note that according to 40 CFR part 60, subpart TTTT, combustion turbines co-firing 25 percent hydrogen by volume could be subcategorized as multi-fuel-fired EGUs because the percent methane by volume could fall below 70 percent, the heating value could fall below 35 MJ/Sm^3, and 10 percent of the heat input could be coming from a fuel not meeting the definition of natural gas.

d. Rural Areas and Small Utility Distribution Systems

As part of the original proposal and during the Small Business Advocacy Review (SBAR) outreach the EPA solicited comment on creating a subcategory for rural electric cooperatives and small utility distribution systems (serving 50,000 customers or less). Commenters expressed concerns that a BSER based on either co-firing hydrogen or CCS may present an additional hardship on economically disadvantaged communities and on small entities, and that the EPA should evaluate potential increased energy costs, transmission upgrade costs, and infrastructure encroachment which may directly affect the disproportionately impacted communities. As described in section VIII.F, the BSER for new stationary combustion turbines does not include hydrogen co-firing and CCS qualifies as the BSER for base load combustion turbines on a nationwide basis. Therefore, the EPA has determined that a subcategory for rural cooperatives and/or small utility distribution systems is not appropriate.

F. Determination of the Best System of Emission Reduction (BSER) for New and Reconstructed Stationary Combustion Turbines

In this section, the EPA describes the technologies it proposed as the BSER for each of the subcategories of new and reconstructed combustion turbines that commence construction after May 23, 2023, as well as topics for which the Agency solicited comment. In the following section, the EPA describes the technologies it is determining are the final BSER for each of the three subcategories of affected combustion turbines and explains its basis for selecting those controls, and not others, as the final BSER. The controls that the EPA evaluated included combusting non-hydrogen lower-emitting fuels (*e.g.,* natural gas and distillate oil), using highly efficient generation, using CCS, and co-firing with low-GHG hydrogen.

For the low load subcategory, the EPA proposed the use of lower-emitting fuels as the BSER. This was consistent with the BSER and performance standards established in the 2015 NSPS for the non-base load subcategory as discussed earlier in section VIII.C.

For the intermediate load subcategory, the EPA proposed an approach under which the BSER was made up of two components: (1) highly efficient generation; and (2) co-firing 30 percent (by volume) low-GHG hydrogen. Each component of the BSER represented a different set of controls, and those controls formed the basis of corresponding standards of performance that applied in two phases. Specifically, the EPA proposed that affected facilities (*i.e.,* facilities that commence construction or reconstruction after May 23, 2023) could apply the first component of the BSER (*i.e.,* highly efficient generation) upon initial startup to meet the first phase of the standard of performance. Then, by 2032, the EPA proposed that affected facilities could apply the second component of the BSER (*i.e.,* co-firing 30 percent (by volume) low-GHG hydrogen) to meet a second and more stringent standard of performance. The EPA also solicited comment on whether the intermediate load subcategory should apply a third component of the BSER: co-firing 96 percent (by volume) low-GHG hydrogen by 2038. In addition, the EPA solicited comment on whether the low load subcategory should also apply the second component of BSER, co-firing 30 percent (by volume) low-GHG hydrogen, by 2032. The Agency proposed that these latter components of the BSER would continue to include the application of highly efficient generation.

For the base load subcategory, the EPA also proposed a multi-component BSER and multi-phase standard of performance. The EPA proposed that each new base load combustion turbine would be required to meet a phase-1 standard of performance based on the application of the first component of the BSER—highly efficient generation—upon initial startup of the affected source. For the second component of the BSER, the EPA proposed two potential technology pathways for base load combustion turbines with corresponding standards of performance. One proposed technology pathway was 90 percent CCS, which base load combustion turbines would install and begin to operate by 2035 to meet the phase-2 standard of performance. A second proposed technology pathway was co-firing low-GHG hydrogen, which base load combustion turbines would implement in two steps: (1) By co-firing 30 percent (by volume) low-GHG hydrogen to meet the phase-2 standard of performance by 2032, and (2) by co-firing 96 percent (by volume) low-GHG hydrogen to meet a phase 3 standard of performance by 2038. Throughout, the Agency proposed base load turbines, like intermediate load turbines, would remain subject to the first component of the BSER based on highly efficient generation.

The proposed approach reflected the EPA's view that the BSER components for the intermediate load and base load subcategories could achieve deeper reductions in GHG emissions by implementing CCS and co-firing low-GHG hydrogen. This proposed approach also recognized that building the infrastructure required to support widespread use of CCS and low-GHG hydrogen technologies in the power sector will take place on a multi-year time scale. Accordingly, new and reconstructed facilities would be aware of their need to ramp toward more stringent phases of the standards, which would reflect application of the more stringent controls in the BSER. This would occur either by co-firing a lower percentage (by volume) of low-GHG hydrogen by 2032 and a higher percentage (by volume) of low-GHG hydrogen by 2038, or with installation and use of CCS by 2035. The EPA also solicited comment on the potential for an earlier compliance date for the second phase.

For the base load subcategory, the EPA proposed two potential BSER pathways because the Agency believed there was more than one viable technology for these combustion turbines to significantly reduce their CO_2 emissions. The Agency also found value in receiving comments on, and potentially finalizing, both BSER pathways to enable project developers to elect how they would reduce their CO_2 emissions on timeframes that make sense for each BSER pathway.[736] The EPA solicited comment on whether the co-firing of low-GHG hydrogen should be considered a compliance pathway for sources to meet a single standard of performance based on the application of CCS rather than a separate BSER pathway. The EPA proposed that there would be earlier opportunities for units to begin co-firing lower amounts of low-GHG hydrogen than to install and begin operating 90 percent CCS systems. However, the Agency proposed that it would likely take longer for those units to increase their co-firing to significant quantities of low-GHG hydrogen. Therefore, in the proposal, the EPA presented the BSER pathways as separate subcategories and solicited comment on the option of finalizing a single standard of performance based on the application of CCS.

For the low load subcategory, the EPA proposed and is finalizing that the BSER is the use of lower-emitting fuels. For the intermediate load subcategory, the EPA proposed and is finalizing that the

[736] The EPA recognizes that standards of performance are technology neutral and that a standard based on application of CCS could be achieved by co-firing hydrogen.

BSER is highly efficient generating technology—simple cycle technology as well as operating and maintaining it efficiently.[737] The EPA is not finalizing a second component of the BSER or a phase-2 standard of performance for intermediate load combustion turbines at this time. For the base load subcategory, the EPA proposed and is finalizing that the first component of the BSER is highly efficient generating technology—combined cycle technology as well as operating and maintaining it efficiently. The EPA proposed and is finalizing a second component of the BSER or a phase-2 standard of performance for base load combustion turbines—efficient generation in combination with 90 percent CCS.

The EPA is not finalizing low-GHG hydrogen co-firing as the second component of the BSER for the intermediate load or base load combustion turbines at this time. (See section VIII.F.5.b for the EPA's explanation of this decision.) With respect to the CCS pathway for base load combustion turbines, the EPA is finalizing a second phase of the standards of performance that includes a single CCS BSER pathway, which includes the use of highly efficient generation and 90 percent CCS. Owners/operators of new and reconstructed base load combustion turbines will be required to meet the second phase standards of performance for 12-operating month rolling averages that begin on or after January 2032, that reflect application of both the phase-1 and phase-2 components of the BSER. Table 3 of this document summarizes the final BSER for combustion turbine EGUs that commence construction or reconstruction after May 23, 2023. The EPA is finalizing standards of performance based on those BSER for each subcategory, as discussed in section VIII.G.

TABLE 3—FINAL BSER FOR COMBUSTION TURBINE EGUS

Subcategory [1]	Fuel	1st Component BSER	2nd Component BSER
Low Load	All Fuels	lower-emitting fuels	N/A.
Intermediate Load	All Fuels	Highly Efficient Simple Cycle Generation.	N/A.
Base Load	All Fuels	Highly Efficient Combined Cycle Generation.	Highly Efficient Combined Cycle Generation Plus 90 Percent CCS Beginning in 2032.

[1] The low load subcategory is applicable to combustion turbines selling 20 percent or less of their potential electric output, the intermediate load subcategory is applicable to combustion turbines selling greater than 20 percent and less than or equal to 40 percent of their potential electric output, and the base load subcategory is applicable to combustion turbines selling greater than 40 percent of their potential electric output.

1. BSER for Low Load Subcategory

This section describes the BSER for the low load (*i.e.*, peaking) subcategory at this time, which is the use of lower-emitting fuels. The Agency proposed and is finalizing a determination that the use of lower-emitting fuels, which the EPA determined to be the BSER for the non-base load subcategory in the 2015 NSPS, is the BSER for this low load subcategory. As explained in section VIII.E.2.b, the EPA is narrowing the definition of the low load subcategory by lowering the electric sales threshold (as compared to the electric sales threshold for non-base load combustion turbines in the 2015 NSPS), so that combustion turbines with higher electric sales would be placed in the intermediate load subcategory and therefore be subject to a more stringent standard based on the more stringent BSER.

a. Background: The Non-Base Load Subcategory in the 2015 NSPS

The 2015 NSPS defined non-base load natural gas-fired EGUs as stationary combustion turbines that (1) burn more than 90 percent natural gas and (2) have net electric sales equal to or less than their design efficiency (not to exceed 50 percent) multiplied by their potential electric output (80 FR 64601; October 23, 2015). These are calculated on 12-operating month and 3-calendar year rolling average bases. The EPA also determined in the 2015 NSPS that the BSER for newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines is the use of lower-emitting fuels. Id. at 64515. These lower-emitting fuels are primarily natural gas with a small allowance for distillate oil (*i.e.*, Nos. 1 and 2 fuel oils), which have been widely used in stationary combustion turbine EGUs for decades.

The EPA also determined in the 2015 NSPS that the standard of performance for sources in this subcategory is a heat input-based standard of 120 lb CO_2/MMBtu. The EPA established this clean-fuels BSER for this subcategory because of the variability in the operation in non-base load combustion turbines and the challenges involved in determining a uniform output-based standard that all new and reconstructed non-base load units could achieve.

Specifically, in the 2015 NSPS, the EPA recognized that a BSER for the non-base load subcategory based on the use of lower-emitting fuels results in limited GHG reductions, but further recognized that an output-based standard of performance could not reasonably be applied to the subcategory. The EPA explained that a combustion turbine operating at a low capacity factor could operate with multiple starts and stops, and that its emission rate would be highly dependent on how it was operated and not its design efficiency. Moreover, combustion turbines with low annual capacity factors typically operated differently from each other, and therefore had different emission rates. The EPA recognized that, as a result, at the time it would not be possible to determine a standard of performance that could reasonably apply to all combustion turbines in the subcategory. For that reason, the EPA further recognized, efficient design[738] and operation would not qualify as the BSER; rather, the BSER should be lower-emitting fuels and the associated standard of performance should be based on heat input. Since the 2015 NSPS, all newly constructed simple cycle turbines have been non-base load units and thus have become subject to this standard of performance.

[737] The EPA sometimes refers to highly efficient generating technology in combination with the best operating and maintenance practices as highly efficient generation. The affected sources must meet standards based on this efficient generating technology upon the effective date of the final rule.

[738] Important characteristics for minimizing emissions from low load combustion turbines include the ability to operate efficiently while operating at part load conditions and the ability to rapidly achieve maximum efficiency to minimize periods of operation at lower efficiencies. These characteristics do not necessarily always align with higher design efficiencies that are determined under steady-state full-load conditions.

b. BSER

Consistent with the rationale of the 2015 NSPS, the EPA proposed and is finalizing that the use of fuels with an emissions rate of less than 160 lb CO_2/MMBtu (*i.e.*, lower-emitting fuels) meets the BSER requirements for the low load subcategory at this time. Use of these fuels is technically feasible for combustion turbines. Natural gas comprises the majority of the heat input for simple cycle turbines and is the lowest cost fossil fuel. In the 2015 NSPS, the EPA determined that natural gas comprised 96 percent of the heat input for simple cycle turbines. See 80 FR 64616 (October 23, 2015). Therefore, a BSER based on the use of natural gas and/or distillate oil would have minimal, if any, costs to regulated entities. The use of lower-emitting fuels would not have any significant adverse energy requirements or non-air quality or environmental impacts, as the EPA determined in the 2015 NSPS. *Id.* at 64616. In addition, the use of fuels meeting this criterion would result in some emission reductions by limiting the use of fuels with higher carbon content, such as residual oil, as the EPA also explained in the 2015 NSPS. *Id.* Although the use of fuels meeting this criterion would not advance technology, in light of the other reasons described here, the EPA proposed and is finalizing that the use of natural gas, Nos. 1 and 2 fuel oils, and other fuels [739] currently specified in 40 CFR part 60, subpart TTTT, qualify as the BSER for new and reconstructed combustion turbine EGUs in the low load subcategory at this time. The EPA also proposed including low-GHG hydrogen on the list of fuels meeting the uniform fuels criteria in 40 CFR part 60, subpart TTTTa. The EPA is finalizing the inclusion of hydrogen, regardless of the production pathway, on the list of fuels meeting the uniform fuels criteria in 40 CFR part 60, subpart TTTTa.[740] The addition of hydrogen (and fuels derived from hydrogen) to 40 CFR part 60, subpart TTTTa, simplifies the recordkeeping and reporting requirements for low load combustion turbines that elect to burn hydrogen.

For the reasons discussed in the 2015 NSPS and noted above, the EPA did not propose that efficient design and operation qualify as the BSER for the low load subcategory. The emissions rate of a low load combustion turbine is highly dependent upon the way the specific combustion turbine is operated. For example, a combustion turbine with multiple startups and shutdowns and operation at part loads will have high emissions relative to if it were operated at steady-state high-load conditions. Important characteristics for reducing GHG emissions from low load combustion turbines are the ability to minimize emissions during periods of startup and shutdown and efficient operation at part loads and while changing loads. If the combustion turbine is frequently operated at part-load conditions with frequent starts and stops, a combustion turbine with a high design efficiency, which is determined at full-load steady-state conditions, would not necessarily emit at a lower GHG rate than a combustion turbine with a lower design efficiency. In addition, combustion turbines with higher design efficiencies have higher initial costs compared to combustion turbines with lower design efficiencies. Since the EPA does not have sufficient information at this time to determine emission reduction for the subcategory it is not possible to determine the cost effectiveness of a BSER based on high efficiency simple cycle turbines.[741]

The EPA solicited comment on whether, and the extent to which, high-efficiency designs also operate more efficiently at part loads and can start more quickly and reach the desired load more rapidly than combustion turbines with less efficient design efficiencies. In addition, the EPA solicited comment on the cost premium of high-efficiency simple cycle turbines. To the extent the Agency received additional relevant information, the EPA was considering promulgating design standard requirements pursuant to CAA section 111(h). However, the EPA did not receive comments that changed the proposal conclusions.

The EPA did not propose the use of CCS or hydrogen co-firing as the BSER (or as a component of the BSER) for low load combustion turbines. The EPA did not propose that CCS is the BSER for simple cycle turbines based on the Agency's assessment that currently available post-combustion amine-based carbon capture systems require that the exhaust from a combustion turbine be cooled prior to entering the carbon capture equipment. The most energy efficient way to cool the exhaust gas is to use a HRSG, which is an integral component of a combined cycle turbine system but is not incorporated in a simple cycle unit. For this reason and due to the high costs of CCS for low load combustion turbines, the Agency did not propose and is not finalizing a determination that CCS qualifies as the BSER for this subcategory of sources.

The EPA did not propose low-GHG hydrogen co-firing as the BSER for low load combustion turbines because not all new combustion turbines can necessarily co-fire higher percentages of hydrogen, there are potential infrastructure issues specific to low load combustion turbines, and at the relatively infrequent levels of utilization that characterize the low load subcategory, a low-GHG hydrogen co-firing BSER would not necessarily result in cost-effective GHG reductions for all low load combustion turbines. As discussed later in this section, the Agency is not determining that low-GHG hydrogen co-firing qualifies as the BSER for combustion turbines. In future rulemaking the Agency could further evaluate the costs and emissions performance of other technologies to reduce emissions from low-load units to determine if other technologies qualify as the BSER.

2. BSER for Intermediate Load Subcategory

This section describes the BSER for new and reconstructed combustion turbines in the intermediate load subcategory. For combustion turbines in the intermediate load subcategory, the BSER is the use of high-efficiency simple cycle turbine technology in combination with the best operating and maintenance practices.

a. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the BSER for intermediate load combustion turbines because, as described earlier in this section, it would achieve few GHG emission reductions compared to highly efficient generation.

b. Highly Efficient Generation

This section includes a discussion of the various highly efficient generation technologies used by owners/operators of combustion turbines. The appropriate technology depends on how the combustion turbine is operated, and the EPA has determined it does not have sufficient information to determine an appropriate output-based emissions standard for low load combustion turbines. At higher capacity factors, emission rates for simple cycle combustion turbines are more consistent, and the EPA has sufficient

[739] The BSER for multi-fuel-fired combustion turbines subject to 40 CFR part 60, subpart TTTT, is also the use of fuels with an emissions rate of 160 lb CO_2/MMBtu or less. The use of these fuels will demonstrate compliance with the low load subcategory.

[740] The EPA is not finalizing a definition of low-GHG hydrogen.

[741] The cost effectiveness calculation is highly dependent upon assumptions concerning the increase in capital costs, the decrease in heat rate, and the price of natural gas.

information to determine a BSER other than lower-emitting fuels.

The use of highly efficient generating technology in combination with the best operating and maintenance practices has been demonstrated by multiple facilities for decades. Notably, over time, as technologies have improved, what is considered highly efficient has changed as well. Highly efficient generating technology is available and offered by multiple vendors for both simple cycle and combined cycle turbines. Both types of combustion turbines can also employ best operating and maintenance practices, which include routine operating and maintenance practices that minimize fuel use.

For simple cycle turbines, manufacturers continue to improve the efficiency by increasing firing temperature, increasing pressure ratios, using intercooling on the air compressor, and adopting other measures. These improved designs allow for improved operating efficiencies and reduced emission rates. Design efficiencies of simple cycle turbines range from 33 to 40 percent. Best operating practices for simple cycle turbines include proper maintenance of the combustion turbine flow path components and the use of inlet air cooling to reduce efficiency losses during periods of high ambient temperatures.

For combined cycle turbines, high-efficiency technology uses a highly efficient combustion turbine engine matched with a high-efficiency HRSG. The most efficient combined cycle EGUs use HRSG with three different steam pressures and incorporate a steam reheat cycle to maximize the efficiency of the Rankine cycle. It is not necessarily practical for owners/operators of combined cycle facilities using a turbine engine with an exhaust temperature below 593 °C or a steam turbine engine smaller than 60 MW to incorporate a steam reheat cycle. Smaller combustion turbine engines, less than those rated at approximately 2,000 MMBtu/h, tend to have lower exhaust temperatures and are paired with steam turbines of 60 MW or less. These smaller combined cycle units are limited to using a HRSG with three different steam pressures, but without a reheat cycle. This increases the heat rate of the combined cycle unit by approximately 2 percent. High efficiency also includes, but is not limited to, the use of the most efficient steam turbine and minimizing energy losses using insulation and blowdown heat recovery. Best operating and maintenance practices include, but are not limited to, minimizing steam leaks, minimizing air infiltration, and cleaning and maintaining heat transfer surfaces.

A potential drawback of combined cycle turbines with the highest design efficiencies is that the facility is relatively complicated and startup times can be relatively long. Combustion turbine manufacturers have invested in fast-start technologies that reduce startup times and improve overall efficiencies. According to the NETL Baseline Flexible Operation Report, while the design efficiencies are the same, the capital costs of fast-start combined cycle turbines are 1.6 percent higher than a comparable conventional start combined cycle facility.[742] The additional costs include design parameters that significantly reduce start times. However, fast-start combined cycle turbines are still significantly less flexible than simple cycle turbines and generally do not serve the same role. The startup time to full load from a hot start takes a simple cycle turbine 5 to 8 minutes, while a combined cycle turbines ranges from 30 minutes for a fast-start combined cycle turbine to 90 minutes for a conventional start combined cycle turbine. The startup time to full load from a cold start takes a simple cycle turbine 10 minutes, while a combined cycle turbines ranges from 120 minutes for a fast-start combined cycle turbine to 250 minutes for a conventional start combined cycle turbine. In addition, fast-start combined cycle turbines require the use of an auxiliary boiler during warm and cold starts.[743] In addition, minimum run times for simple cycle aeroderivative engines and combined cycle EGUs equal one minute and 120 minutes, respectively. Minimum downtime for the same group is five minutes and 60 minutes, respectively. Finally, simple cycle aeroderivative turbines have no limit to the number of starts per year. Combined cycle EGUs are limited in the number of starts, and additional maintenance costs will occur if the hours/start ratio drops below 25. The model combined cycle turbines in the NETL Baseline Flexible Operation Report use a HRSG with three different steam pressures and a reheat cycle. While the use of this type of HRSG increases design efficiencies at steady state conditions, it increases the capital costs and decreases the flexibility (*e.g.*, longer start times) of the combined cycle turbine. While less common, combined cycle turbines can be designed with a relatively simple HRSG that produces either a single or two pressures of steam without a reheat cycle. While design efficiencies are lower, the combined cycle turbines are more flexible and have the potential to operate similar to at least a portion of the simple cycle turbines in the intermediate load subcategory and provide the same value to the grid.

The EPA solicited comment on whether additional technologies for new simple and combined cycle EGUs that could reduce emissions beyond what is currently being achieved by the best performing EGUs should be included in the BSER. Specifically, the EPA sought comment on whether pressure gain combustion should be incorporated into a standard of performance based on an efficient generation BSER for both simple and combined cycle turbines. In addition, the EPA sought comment on whether the HRSG for combined cycle turbines should be designed to utilize supercritical steam conditions or to utilize supercritical CO_2 as the working fluid instead of water; whether useful thermal output could be recovered from a compressor intercooler and boiler blowdown; and whether fuel preheating should be implemented. Commenters generally noted that these technologies are promising, but that because the EPA did not sufficiently evaluate the BSER criteria in the proposal and none of these technologies should be incorporated as part of the BSER. The EPA continues to believe these technologies are promising, but the Agency is not including them as part of the BSER at this time.

The EPA also solicited comment on whether the use of steam injection is applicable to intermediate load combustion turbines. Steam injection is the use of a relatively simple and low-cost HRSG to produce steam, but instead of recovering the energy by expanding the steam through a steam turbine, the steam is injected into the compressor and/or through the fuel nozzles directly into the combustion chamber and the energy is extracted by the combustion turbine engine.[744] Advantages of steam injection include improved efficiency and increased output of the combustion turbine as well as reduced NO_X emissions. Combustion turbines using steam

[742] "Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation." DOE/NETL–2023/3855. May 5, 2023.

[743] Fast start combined cycle turbine do not use an auxiliary boiler during hot starts and conventional start combined cycle turbine do not have auxiliary boilers.

[744] A steam injected combustion turbine would be considered a combined cycle combustion turbine (for NSPS purposes) because energy from the turbine engine exhaust is recovered in a HRSG and that energy is used to generate additional electricity.

injection have characteristics in-between simple cycle and combined cycle combustion turbines. They are more efficient, but more complex and have higher capital costs than simple cycle combustion turbines without steam injection. Conversely, compared to combined cycle EGUs, simple cycle combustion turbines using steam injection are simpler, have shorter construction times, and have lower capital costs, but have lower efficiencies.[745] [746] Combustion turbines using steam injection can start quickly, have good part-load performance, and can respond to rapid changes in demand, making the technology a potential solution for reducing GHG emissions from intermediate load combustion turbines. A potential drawback of steam injection is that the additional pressure drop across the HRSG can reduce the efficiency of the combustion turbine when the facility is running without the steam injection operating.

The EPA is aware of a limited number of combustion turbines that are using steam injection that have maintained 12-operating month emission rates of less than 1,000 lb CO_2/MWh-gross. Commenters stated that steam injection does not qualify as the BSER because it has not been adequately demonstrated and the EPA did not include sufficient analysis of the technology in the proposal to determine it as the BSER for intermediate load combustion turbines. The EPA continues to believe the technology is promising and it may be used to comply with the standard of performance, but the Agency is not determining that it is the BSER for intermediate load combustion turbines at this time. In a potential future rulemaking, the Agency could further evaluate the costs and emissions performance of steam injection to determine if the technology qualifies as the BSER.

i. Adequately Demonstrated

The EPA proposed and is finalizing that highly efficient simple cycle designs are adequately demonstrated because highly efficient simple cycle turbines have been demonstrated by multiple facilities for decades, the efficiency improvements of the most efficient designs are incremental in nature and do not change in any significant way how the combustion turbine is operated or maintained, and the levels of efficiency that the EPA is proposing have been achieved by many recently constructed combustion turbines. Therefore, efficient generation technology described in this BSER is commercially available and the standards of performance are achievable.

ii. Costs

In general, advanced generation technologies enhance operational efficiency compared to lower efficiency designs. Such technologies present little incremental capital cost compared to other types of technologies that may be considered for new and reconstructed sources. In addition, more efficient designs have lower fuel costs, which offsets at least a portion of the increase in capital costs.

For the intermediate load subcategory, the EPA considers that the costs of high-efficiency simple cycle combustion turbines are reasonable. As described in the subcategory section, the cost of combustion turbine engines is dependent upon many factors, but the EPA estimates that that the capital cost of a high-efficiency simple cycle turbine is 10 percent more than a comparable lower efficiency simple cycle turbine. Assuming all other costs are the same and that the high-efficiency simple cycle turbine uses 8 percent less fuel, high-efficiency simple cycle combustion turbines have a lower LCOE compared to standard efficiency simple cycle combustion turbines at a 12-operating month capacity factor of approximately 31 percent. At a 20 percent and 15 percent capacity factors, the compliance costs are $1.5/MWh and $35/metric ton and $3.0/MWh and $69/metric ton, respectively. The EPA has determined that the incremental costs the use of high efficiency simple cycle turbines as the BSER for intermediate load combustion turbines is reasonable. The EPA notes that the approach the Agency used to estimate these costs have a relatively high degree of uncertainty and are likely high given the common use of high efficiency simple cycle turbines without a regulatory driver.

The EPA considered but is not finalizing combined cycle unit design for combustion turbines as the BSER for the intermediate load subcategory because it is unclear if combined cycle turbines could serve the same role as intermediate load simple cycle turbines as a whole. Specifically, the EPA does not have sufficient information to determine that an intermediate load combined cycle turbine can start and stop with enough flexibility to provide the same level of grid support as intermediate load simple cycle turbines as a whole. In addition, the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear. Intermediate load combustion turbines start and stop so frequently that there would often not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

Some commenters agreed with the proposed rationale of the EPA, and other commenters disagreed and said that combined cycle turbine technology is cost effective and lower-emitting than simple cycle turbine technology and therefore qualifies as the BSER for intermediate load combustion turbines. Commenters supporting combined cycle technology as the BSER submitted cost information that indicated that combined cycle EGUs have lower capital costs and LCOE than simple cycle turbines. However, the commenters compared capital costs of larger combined cycle turbines to smaller simple cycle turbines and did not account for economies of scale. The EPA has concluded that the appropriate cost comparison is for combustion turbines with the same rated net output.[747] Comparing the costs of different size EGUs is not appropriate because these EGUs provide different grid services. In addition, the commenters did not account for startup costs and the time required for a steam turbine to begin operating when determining the LCOE.

The EPA considered the operation of simple cycle turbine to determine the potential for simple cycle turbine to add a HRSG while continuing to operate in the same manner, providing the same grid services, as current simple cycle turbines. As noted previously, aeroderivative simple cycle turbines have shorter run times per start than frame type simple cycle turbines at the same capacity factor. At an annual capacity factor of 20 percent, the median run time per start for aeroderivative and frame simple cycle turbines is 12 and 16 hours respectively. At an annual capacity factor of 30 percent, the average run times per start increase to 17 and 26 hours for aeroderivative and frame turbines respectively. The higher operating times of frame type simple cycle turbines,

[745] Bahrami, S., *et al.* (2015). *Performance Comparison between Steam Injected Gas Turbine and Combined Cycle during Frequency Drops.* Energies 2015, Volume 8. *https://doi.org/10.3390/en8087582.*

[746] Mitsubishi Power. *Smart-AHAT (Advanced Humid Air Turbine). https://power.mhi.com/products/gasturbines/technology/smart-ahat.*

[747] The costing approach used by the EPA compares a combined cycle turbine using a smaller turbine engine plus a steam turbine to match the output from a simple cycle turbine.

along with the larger size of frame type turbines, indicate that combined cycle technology could be applicable to at least a portion of intermediate load combustion turbines. In future rulemakings addressing GHGs from new as well as existing combustion turbines, the EPA intends to further evaluate the costs and potential emission reductions of the use of faster starting and lower cost HRSG technology for intermediate load combustion turbines to determine if the technology does in fact qualify as the BSER.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Use of highly efficient generation reduces all non-air quality health and environmental impacts and energy requirements assuming it displaces less efficient or higher-emitting generation. Even when operating at the same input-based emissions rate, the more efficient a unit is, the less fuel is required to produce the same level of output; and, as a result, emissions are reduced for all pollutants. The use of highly efficient combustion turbines, compared to the use of less efficient combustion turbines, reduces all pollutants.[748] By the same token, because improved efficiency allows for more electricity generation from the same amount of fuel, it will not have any adverse effects on energy requirements.

Designating highly efficient generation as part of the BSER for new and reconstructed intermediate load combustion turbines will not have significant impacts on the nationwide supply of electricity, electricity prices, or the structure of the electric power sector. On a nationwide basis, the additional costs of the use of highly efficient generation will be small because the technology does not add significant costs and at least some of those costs are offset by reduced fuel costs. In addition, at least some of these new combustion turbines would be expected to incorporate highly efficient generation technology in any event.

iv. Extent of Reductions in CO_2 Emissions

The EPA estimated the potential emission reductions associated with a standard that reflects the application of highly efficient generation as BSER for the intermediate load subcategory. As discussed in section VIII.G.1, the EPA determined that the standards of performance reflecting this BSER are 1,170 lb CO_2/MWh-gross for intermediate load combustion turbines.

Between 2015 and 2022, 113 simple cycle turbines, an average of 16 per year, commenced operation. Of these, 112 reported 12-operating month capacity factors. The EPA estimates that 23 simple cycle turbines operated at 12-operating month capacity factors greater than 20 percent and potentially would be considered intermediate combustion turbines. To estimate reductions, the EPA assumed that the number of simple cycle turbines constructed between 2015 and 2022 and the operation of those combustion turbines would continue on an annual basis.[749] For each simple cycle turbine that operated at a capacity greater than 20 percent, the EPA determined the percent reduction in emissions, based on the maximum 12-operating months intermediate load emission rate, that would be required to comply with the final NSPS for intermediate load turbines. The EPA then applied that same percent reduction in emissions to the average operating capacity factor to determine the emission reductions from the NSPS. Using this approach, the EPA estimates that the intermediate load standard will impact approximately a quarter of new simple cycle turbines. The EPA divided the total amount of calculated reductions for intermediate load simple cycle turbines built between 2015 and 2022 and divided that value by 7 (the number of years evaluated) to get estimated annual reductions. This approach results in annual reductions of 31,000 tons of CO_2 as well as 8 tons of NO_X. The emission reductions are projected to result primarily from building additional higher efficiency aeroderivative simple cycle turbines instead of less efficient frame simple cycle turbines. The reduced emissions come from relatively small reductions in the emission rates of the intermediate load aeroderivative simple cycle turbines. This is a snapshot of projected emission reductions from applying the NSPS retroactively to 2022. If more intermediate load simple cycle turbines are built in the future, the emission reductions would be higher than this estimate. Conversely, if fewer intermediate load simple cycles are built, the emission reductions would be lower than the EPA's estimate.

Importantly, the "highly efficient generation" which the EPA has determined to be the BSER for new and reconstructed intermediate load combustion turbines and to be the first component BSER for base load stationary combustions, is not the same as the "heat rate improvements" (HRI, or "efficiency improvements") that the EPA determined to be the BSER for existing coal-fired steam generating EGUs in the ACE Rule. As noted earlier in this document, the EPA has concluded that the suite of HRI in the ACE Rule is not an appropriate BSER for existing coal-fired EGUs. In the EPA's technical judgment, the suite of HRI set forth in the ACE Rule would provide negligible CO_2 reductions at best and, in many cases, may increase CO_2 emissions because of the "rebound effect," which is explained and discussed in section VII.D.4.a.iii of this preamble. Increased CO_2 emissions from the "rebound effect" can occur when a coal-fired EGU improves its efficiency (heat rate), which can move the unit up on the dispatch order—resulting in an EGU operating for more hours during the year than it would have without having done the efficiency improvements. There is also the possibility that a more efficient coal-fired EGU could displace a lower emitting generating source, further exacerbating the problem.

Conversely, including "highly efficient generation" as a component of the BSER for new and reconstructed does not create this risk of displacing a lower-emitting generating source. A new highly efficient stationary combustion turbine may be dispatched more than it would have been if it were not built as a highly efficient turbine, but it is more likely to displace an existing coal-fired EGU or a less efficient existing stationary combustion turbine. It would be unlikely to displace a renewable generating source.

For base load stationary combustion turbines, "highly efficient generation" is the first component of the BSER—with 90 percent capture CCS being the second component of the BSER. This is very similar to the Agency's BSER determination for the NSPS for new fossil fuel-fired steam generating units. In that final rule, the EPA established standards of performance for newly constructed fossil fuel-fired steam generating units based on the performance of a new highly efficient supercritical pulverized coal (SCPC) EGU implementing post-combustion partial CCS technology, which the EPA determined to be the BSER for these sources.[750]

[748] The emission reduction comparison is done assuming the same level of operation. Overall emission impacts would be different if the more efficient combustion turbine operates more then the baseline.

[749] This is a simplified assumption that does not take into account changing market conditions that could change the makeup and operation of new combustion turbines.

[750] See 80 FR 64510 (October 23, 2015).

v. Promotion of the Development and Implementation of Technology

The EPA also considered the potential impact of selecting highly efficient simple cycle generation technology as the BSER for the intermediate load subcategory in promoting the development and implementation of improved control technology. New highly efficient simple cycle turbines are more efficient than the average new simple cycle turbine and a standard based on the performance of the most efficient, best performing simple cycle turbine will promote penetration of the most efficient units throughout the industry. Accordingly, consideration of this factor supports the EPA's proposal to determine this technology to be the BSER.

c. Low-GHG Hydrogen and CCS

The EPA did not propose and is not finalizing either CCS or co-firing low-GHG hydrogen as the first component of the BSER for intermediate load combustion turbines, for the reasons given in sections VIII.F.4.c.iii (CCS) and VIII.F.5 (low-GHG hydrogen).

d. Summary of BSER Determinations

The EPA is finalizing that highly efficient generating technology in combination with the best operating and maintenance practices is the BSER for intermediate load combustion turbines. Specifically, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices is the BSER for intermediate load combustion turbines.

Highly efficient generation qualifies the BSER because it is adequately demonstrated, it can be implemented at reasonable cost, it achieves emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements. The fact that it promotes greater use of advanced technology provides additional support; however, the EPA considers highly efficient generation to the BSER for intermediate load combustion turbines even without taking this factor into account.

3. BSER for Base Load Subcategory—First Component

This section describes the first component of the BSER for newly constructed and reconstructed combustion turbines in the base load subcategory. For combustion turbines in the base load subcategory, the first component of the BSER is the use of high-efficiency combined cycle technology in combination with the best operating and maintenance practices.

a. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the BSER for base load combustion turbines because, as described earlier in this section, it would achieve few GHG emission reductions compared to highly efficient generation.

b. Highly Efficient Generation

i. Adequately Demonstrated

The EPA proposed and is finalizing that highly efficient combined cycle designs are adequately demonstrated because highly efficient combined cycle EGUs have been demonstrated by multiple facilities for decades, and the efficiency improvements of the most efficient designs are incremental in nature and do not change in any significant way how the combustion turbine is operated or maintained. Due to the differences in HRSG efficiencies for smaller combined cycle turbines, the EPA proposed and is finalizing less stringent standards of performance for smaller base load turbines with base load ratings of less than 2,000 MMBtu/h relative to those for larger base load turbines. The levels of efficiency that the EPA is proposing have been achieved by many recently constructed combustion turbines. Therefore, efficient generation technology described in this BSER is commercially available and the standards of performance are achievable.

ii. Costs

For the base load subcategory, the EPA considers the cost of high-efficiency combined cycle EGUs to be reasonable. While the capital costs of a higher efficiency combined cycle EGUs are 1.9 percent higher than standard efficiency combined cycle EGUs, fuel use is 2.6 percent lower.[751] The reduction in fuel costs fully offset the capital costs at capacity factors of 40 percent or greater over the expected 30-year life of the facility. Therefore, a BSER based on the use of high-efficiency combined cycle combustion turbines for base load combustion turbines would have minimal, if any, overall compliance costs since the capital costs would be recovered through reduced fuel costs over the expected 30-year life of the facility.

[751] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022), *https://www.osti.gov/servlets/purl/1893822*.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Use of highly efficient generation reduces all non-air quality health and environmental impacts and energy requirements as compared to use of less efficient generation. Even when operating at the same input-based emissions rate, the more efficient a unit is, the less fuel is required to produce the same level of output; and, as a result, emissions are reduced for all pollutants. The use of highly efficient combustion turbines, compared to the use of less efficient combustion turbines, reduces all pollutants. By the same token, because improved efficiency allows for more electricity generation from the same amount of fuel, it will not have any adverse effects on energy requirements.

Designating highly efficient generation as part of the BSER for new and reconstructed base load combustion turbines will not have significant impacts on the nationwide supply of electricity, electricity prices, or the structure of the electric power sector. On a nationwide basis, the additional costs of the use of highly efficient generation will be small because the technology does not add significant costs and at least some of those costs are offset by reduced fuel costs. In addition, at least some of these new combustion turbines would be expected to incorporate highly efficient generation technology in any event.

iv. Extent of Reductions in CO_2 Emissions

The EPA used a similar approach to estimating emission reductions for base load combustion turbines as intermediate load combustion turbines, except the Agency reviewed recently constructed combined cycle EGUs. As discussed in section VIII.G.1, the EPA determined that the standard of performance reflecting this BSER is 800 lb CO_2/MWh-gross for base load combustion turbines. The Agency assumed all new combined cycle turbines would be impacted by the base load emissions standard. Between the beginning of 2015 and the beginning of 2022, 129 combined cycle turbines, an average of 18 per year, commenced operation. Of those combined cycle turbines, 107 had 12-operating month emissions data. For each of these 107 combined cycle turbines that had a maximum 12-operating month emissions rate greater than 800 lb CO_2/MWh-gross, the EPA determined the reductions that would occur assuming the combined cycle turbine reduced its emissions rate to 800 lb CO_2/MWh-gross and continued to operate at its average capacity factor. The EPA summed the results and divided by 8 (the number of years evaluated) to estimate the annual GHG reductions that will result from this final rule. The EPA estimates that the base load standard will result in annual reductions of 313,000 tons of CO_2 as well as 23 tons of NO_X. The reductions increase each year and in year 3 the annual reductions would be 939,000 tons of CO_2 and 69 tons of NO_X.

v. Promotion of the Development and Implementation of Technology

The EPA also considered the potential impact of selecting highly efficient generation technology as the BSER in promoting the development and implementation of improved control technology. The highly efficient combustion turbines are more efficient and lower emitting than the average new combustion turbine generation technology. Determining that highly efficient turbines are a component of the BSER will advance penetration of the best performing combustion turbines throughout the industry—and will incentivize manufacturers to offer improved turbines that meet the final standard of performance associated with application of the BSER. Accordingly, consideration of this factor supports the EPA's proposal to determine this technology to be the BSER.

c. Low-GHG Hydrogen and CCS

The EPA did not propose and is not finalizing either CCS or co-firing low-GHG hydrogen as the first component of the BSER for base load combustion turbines, for the reasons given in sections VIII.F.4.c.iii (CCS) and VIII.F.5 (low-GHG hydrogen).

d. Summary of BSER Determinations

The EPA is finalizing that highly efficient generating technology in combination with the best operating and maintenance practices is the BSER for first component of the BSER for base load combustion turbines. The phase-1 standards of performance are based on the application of that technology. Specifically, the use of highly efficient combined cycle technology in combination with best operating and maintenance practices is the first component of the BSER for base load combustion turbines.

Highly efficient generation qualifies as the BSER because it is adequately demonstrated, it can be implemented at reasonable cost, it achieves emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements. The fact that it promotes greater use of advanced technology provides additional support; however, the EPA considers highly efficient generation to be a component of the BSER for base load combustion turbines even without taking this factor into account.

4. BSER for Base Load Subcategory—Second Component

a. Authority To Promulgate a Multi-Part BSER and Standard of Performance

The EPA's approach of promulgating standards of performance that apply in multiple phases, based on determining the BSER to be a set of controls with multiple components, is consistent with CAA section 111(b). That provision authorizes the EPA to promulgate "standards of performance," CAA section 111(b)(1)(B), defined, in the singular, as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER]." CAA section 111(a)(1). CAA section 111(b)(1)(B) further provides, "[s]tandards of performance . . . shall become effective upon promulgation." In this rulemaking, the EPA is determining that the BSER is a set of controls that, depending on the subcategory, include highly efficient generation plus use of CCS. The EPA is determining that affected sources can apply the first component of the BSER—highly efficient generation—by the effective date of the final rule and can apply both the first and second components of the BSER—highly efficient generation in combination with 90 percent CCS—in 2032.

Accordingly, the EPA is finalizing standards of performance that reflect the application of this multi-component BSER and that take the form of standards of performance that affected sources must comply with in two phases. This multi-phase standard of performance "become[s] effective upon promulgation." CAA section 111(b)(1)(B). That is, upon promulgation, affected sources become legally subject to the multi-phase standard of performance and must comply with it by its terms. Specifically, affected sources must comply with the first phase standards, which are based on the application of the first component of the BSER, upon initial startup of the facility. They must comply with the second phase standards, which are based on the application of both the first and second components of the BSER, beginning January 2032.

D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the "adequately demonstrated" criterion—even if the controls require some amount of "lead time," which the court has defined as "the time in which the technology will have to be available." [752] The caselaw's interpretation of "adequately demonstrated" to accommodate lead time accords with common sense and the practical experience of certain types of controls, discussed below. Consistent with this caselaw, the phased implementation of the standards of performance in this rule ensures that facilities have sufficient lead time for planning and implementation of the use of CCS-based controls necessary to comply with the second phase of the standards, and thereby ensures that the standards are achievable. For further discussion of this point, see section V.C.2.b.iii.

The EPA has promulgated several prior rulemakings under CAA section 111(b) that have similarly provided the regulated sector with lead time to accommodate the availability of technology, which also serve as precedent for the two-phase implementation approach proposed in this rule. See 81 FR 59332 (August 29, 2016) (establishing standards for municipal solid waste landfills with 30-month compliance timeframe for installation of control device, with interim milestones); 80 FR 13672, 13676 (March 16, 2015) (establishing stepped compliance approach to wood heaters standards to permit manufacturers lead time to develop, test, field evaluate and certify current technologies to meet Step 2 emission limits); 78 FR 58416, 58420 (September 23, 2013) (establishing multi-phased compliance deadlines for revised storage vessel standards to permit sufficient time for production of necessary supply of control devices and for trained personnel to perform installation); 77 FR 56422, 56450 (September 12, 2012) (establishing standards for petroleum refineries, with 3-year compliance timeframe for installation of control devices); 71 FR 39154, 39158 (July 11, 2006) (establishing standards for stationary compression ignition internal combustion engines, with 2- to 3-year compliance timeframe and up to 6 years for certain emergency fire pump engines); 70 FR 28606, 28617 (March 18, 2005) (establishing two-phase caps for

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

mercury standards of performance from new and existing coal-fired electric utility steam generating units based on timeframe when additional control technologies were projected to be adequately demonstrated).[753] *Cf.* 80 FR 64662, 64743 (October 23, 2015) (establishing interim compliance period to phase in final power sector GHG standards to allow time for planning and investment necessary for implementation activities).[754] In each action, the standards and compliance timelines were effective upon the final rule, with affected facilities required to comply consistent with the phased compliance deadline specified in each action.

It should be noted that the multi-phased implementation of the standards of performance that the EPA is finalizing in this rule, like the delayed or multi-phased standards in prior rules just described, is distinct from the promulgation of revised standards of performance under the 8-year review provision of CAA section 111(b)(1)(B). As discussed in section VIII.F, the EPA has determined that the proposed BSER—highly efficient generation and use of CCS—meet all of the statutory criteria and are adequately demonstrated for the compliance timeframes being finalized. Thus, the second phase of the standard of performance applies to affected facilities that commence construction after May 23, 2023 (the date of the proposal). In contrast, when the EPA later reviews and (if appropriate) revises a standard of performance under the 8-year review provision, then affected sources that commence construction after the date of that proposal of the revised standard of performance will be subject to that standard, but not sources that commenced construction earlier.

Similarly, the multi-phased implementation of the standard of performance that the EPA is including in this rule is also distinct from the promulgation of emission guidelines for existing sources under CAA section 111(d). Emission guidelines only apply to existing sources, which are defined in CAA section 111(a)(6) as ‘‘any stationary source other than a new source.’’ Because new sources are defined relative to the proposal of standards pursuant to CAA section 111(b)(1)(B), standards of performance adopted pursuant to emission guidelines will only apply to sources constructed before May 23, 2023, the date of the proposed standards of performance for new sources.

[753] *Cf. New Jersey* v. *EPA,* 517 F.3d 574, 583–584 (D.C. Cir. 2008) (vacating rule on other grounds).

[754] *Cf. West Virginia* v. *EPA,* 597 U.S. 697 (2022) (vacating rule on other grounds).

b. BSER for the Intermediate Load Subcategory—Second Component

The EPA proposed that the second component of the BSER for intermediate load combustion turbines was co-firing 30 percent low-GHG hydrogen in 2032. As discussed in section VIII.F.5.b, the EPA is not determining that low-GHG hydrogen qualifies as the BSER at this time. Therefore, the Agency is not finalizing a second component of the BSER for intermediate load combustion turbines.

c. BSER for Base Load Subcategory—Second Component

i. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the second component of the BSER for intermediate or base load combustion turbines because it would achieve few emission reductions, compared to highly efficient generation without or in combination with the use of CCS.

ii. Highly Efficient Generation

For the reasons described above, the EPA is determining that highly efficient generation in combination with best operating and maintenance practices continues to be a component of the BSER that is reflected in the second phase of the standards of performance for base load combustion turbine EGUs. Highly efficient generation reduces fuel use and, therefore, the amount of CO_2 that must be captured by a CCS system. Since a highly efficient turbine system would produce less flue gas that would need to be treated (compared to a less efficient turbine system), physically smaller carbon capture equipment may be used—potentially reducing capital, fixed, and operating costs.

iii. Hydrogen Co-Firing

The EPA proposed a pathway for the second component of the BSER for base load combustion turbines of co-firing 30 percent low-GHG hydrogen in 2032 increasing to 96 percent low-GHG hydrogen co-firing in 2038. As discussed in section VIII.F.5.b of this preamble, the EPA is not finalizing a determination that low-GHG hydrogen co-firing qualifies as the BSER. Therefore, the Agency is not finalizing a second component low-GHG hydrogen co-firing pathway of the BSER for base load combustion turbines. As the EPA's standard of performance is technology neutral, however, affected sources may comply with it by co-firing hydrogen.

iv. CCS

(A) Overview

In this section of the preamble, the EPA explains its rationale for finalizing that CCS with 90 percent capture is a component of the BSER for new base load combustion turbines. CCS is a control technology that can be applied at the stack of a combustion turbine EGU, achieves substantial reductions in emissions and can capture and permanently sequester at least 90 percent of the CO_2 emitted by combustion turbines. The technology is adequately demonstrated, given that it has been operated on a large scale and is widely applicable to these sources, and there are vast sequestration opportunities across the continental U.S. Additionally, the costs for CCS are reasonable in light of recent technology cost declines and policies including the tax credit under IRC section 45Q. Moreover, the non-air quality health and environmental impacts of CCS can be mitigated, and the energy requirements of CCS are not unreasonably adverse. The EPA's weighing of these factors together provides the basis for finalizing 90 percent capture CCS as a component of BSER for these sources. In addition, this BSER determination aligns with the caselaw, discussed in section V.C.2.h of the preamble, stating that CAA section 111 encourages continued advancement in pollution control technology.

This section incorporates by reference the parts of section VII.C.1.a. of this preamble that discuss the many aspects of CCS that are common to both steam generating units and to new combustion turbines. This includes the discussion of simultaneous demonstration of CO_2 capture, transport, and sequestration discussed at VII.C.1.a.i(A); the discussion of CO_2 capture technology used at coal-fired steam generating units at VII.C.1.a.i(B) (the Agency explains below why that record is also relevant to our BSER analysis for new combustion turbines); the discussion of CO_2 transport at VII.C.1.a.i(C); and the discussion of geologic storage of CO_2 at VII.C.1.a.i(D). And the record supporting that transport and sequestration of CO_2 from coal-fired units is adequately demonstrated and meets the other requirements for BSER applies as well to transport and sequestration of CO_2 from combustion turbines.

The primary differences between using post-combustion capture from a coal combustion flue gas and a natural gas combustion flue gas are associated with the level of CO_2 in the flue gas stream and the levels of other pollutants that must be removed. In coal combustion flue gas, the concentration of CO_2 is typically approximately 13 to 15 volume percent, while the concentration of CO_2 from natural gas-fired combined cycle combustion flue gas is approximately 3 to 4 volume percent.[755] Capture of CO_2 at dilute concentrations is more challenging but there are commercially available amine-based solvents that can be used with dilute CO_2 streams to achieve 90 percent capture. In addition, flue gas from a coal-fired steam EGU contains a variety of non-carbonaceous components that must be removed to meet environmental limits (*e.g.*, mercury and other metals, particulate matter (fly ash), and acid gases (including sulfur dioxide (SO_2) and hydrogen chloride and hydrogen fluoride). When amine-based post-combustion carbon capture is used with a coal-fired EGU, the flue gas stream must be further cleaned, sometimes beyond required environmental standards, to avoid the fouling of downstream process equipment and to prevent degradation of the amine solvent. Absent pretreatment of the coal combustion flue gas, the amines can absorb SO_2 and other acid gases to form heat stable salts, thereby degrading the performance of the solvent. Amine solvents can also experience catalytic oxidative degradation in the presence of some metal contaminants. Thermal oxidation of the solvent can also occur but can be mitigated by interstage cooling of the absorber column. Natural gas combustion flue gas typically contains very low (if any) levels of SO_2, acid gases, fly ash, and metals. Therefore, fouling and solvent degradation are less of a concern for carbon capture from natural gas-fired EGUs.

New natural gas-fired combustion turbine EGUs also have the option of using oxy-combustion technology—such as that currently being demonstrated and developed by NET Power. As discussed earlier, the NET Power system uses oxy-combustion (combustion in pure oxygen) of natural gas and a high-pressure supercritical CO_2 working fluid (instead of steam) to produce electricity in a combined cycle turbine configuration. The combustion products are water and high-purity, pipeline-ready CO_2 which is available for sequestration or sale to another industry. The NET Power technology does not involve solvent-based CO_2 separation and capture since pure CO_2 is a product of the process. The NET Power technology is not currently applicable to coal-fired steam generating utility boilers—though it could be utilized with combustion of gasified coal or other solid fossil fuels (*e.g.*, petroleum coke).

For new base load combustion turbines, the EPA proposed that CCS with a 90 percent capture rate, beginning in 2035, meets the BSER criteria. Some commenters agreed with the EPA that CCS for base load combustion turbines satisfies the BSER criteria. Other commenters claimed that CCS is not a suitable BSER for new base load combustion turbines. The EPA disagrees with these commenters.

As with existing coal-fired steam generating units, CCS applied to new combined cycle combustion turbines has three major components: CO_2 capture, transportation, and sequestration/storage. CCS with 90 percent capture has been adequately demonstrated for combined cycle combustion turbines for many of the same reasons described in section VII.C.1.a.i. The Bellingham Energy Center, a natural gas-fired combined cycle combustion turbine in south central Massachusetts, successfully applied post-combustion carbon capture using the Fluor Econamine FG Plus℠ amine-based solvent from 1991–2005 with 85–95 percent CO_2 capture.[756] The plant captured approximately 365 tons of CO_2 per day from a 40 MW slip stream [757] and was ultimately shut down and decommissioned primarily due to rising gas prices.

As discussed in further detail below, additional natural gas-fired combined cycle combustion turbine CCS projects are in the planning stage, which confirms that CCS is becoming accepted across the industry. As discussed above, CCS with 90 percent capture has been demonstrated for coal-fired steam generating units, and that information forms part of the basis for the EPA's determination that CCS with 90 percent capture has been have adequately demonstrated for these combustion turbines. Statements from vendors and the experience of industrial applications of CCS provide further support that post-combustion CCS with 90 percent capture is adequately demonstrated for these combustion turbines.

The EPA's analysis of the transportation and sequestration components of CCS for new base load combustion turbines is similar to its analysis of those components for existing coal-fired steam generating units and, therefore, for much the same reasons, the EPA is determining that each of those components is adequately demonstrated, and that CCS as a whole—including those components when combined with the 90 percent CO_2 capture component—is adequately demonstrated. In addition, new sources may consider access to CO_2 transport and storage sites in determining where to build, and the EPA expects that since this rule was proposed, companies siting new base load combustion turbines have taken into consideration the likelihood of a regulatory regime requiring significant emissions reductions.

The use of CCS at 90 percent capture can be implemented at reasonable cost because it allows affected sources to maximize the benefits of the IRC section 45Q tax credit. Finally, any adverse health and environmental impacts and energy requirements are limited and, in many cases, can be mitigated or avoided. It should also be noted that a determination that CCS is the BSER for these units will promote further use and development of this advanced technology. After balancing these factors, the EPA is determining that utilization of CCS with 90 percent capture for new base load combustion turbine EGUs satisfies the criteria for BSER.

(B) Adequately Demonstrated

The legal test for an adequately demonstrated system, and an achievable standard, has been discussed at length above. (See sections V.C.2.b and VII.C.a.i of this preamble). As previously noted, concepts of adequate demonstration and achievability are closely related: "[i]t is the *system* which must be adequately demonstrated and the *standard* which must be achievable," [758] based on application of the system. An achievable standard means a standard based on the EPA's finding that sufficient evidence exists to reasonably determine that the affected sources in the source category can adopt a specific system of emission reduction to achieve the specified degree of emission limitation. The foregoing sections have shown that CCS, specifically using amine post-combustion CO_2 capture, is adequately demonstrated for existing coal units,

[755] NETL Carbon Dioxide Capture Approaches. *https://netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/capture-approaches.*

[756] Fluor Econamine FG Plus℠ brochure. *https://a.fluor.com/f/1014770/x/a744f915e1/econamine-fg-plus-brochure.pdf.*

[757] "Commercially Available CO_2 Capture Technology" Power, (Aug 2009). *https://www.powermag.com/commercially-available-co2-capture-technology/.*

[758] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (1973).

and that a 90 percent capture standard is achievable.[759]

Pursuant to *Lignite Energy Council* v. *EPA,* the EPA may extrapolate based on data from a particular kind of source to conclude that the technology at issue will also be effective at a similar source.[760] This standard is satisfied in our case, because of the essential ways in which CO_2 capture at coal-fired steam generating units is identical to CO_2 capture at natural gas-fired combined cycle turbines. As detailed in section VII.C.1.a.i(B), amine-based CO_2 capture removes CO_2 from post-combustion flue gas by reaction of the CO_2 with amine solvent. The same technology (*i.e.,* the same solvents and processes) that is employed on coal-fired steam generating units—and that is employed to capture CO_2 from fossil fuel combustion in other industrial processes—can be applied to remove CO_2 from the post-combustion flue gas of natural gas-fired combined cycle EGUs. In fact, the only differences in application of amine-based CO_2 capture on a natural gas-fired combined cycle unit relative to a coal-fired steam generating unit are related to the differences in composition of the respective post-combustion flue gases, and as explained below, these differences do not preclude achieving 90 percent capture from a gas-fired turbine.

First, while coal flue gas contains impurities including SO_2, PM, and trace minerals that can affect the downstream CO_2 process, and thus coal flue gas requires substantial pre-treatment, the post-combustion flue gas of natural gas-fired combustion turbines has few, if any, impurities that would impact the downstream CO_2 capture plant. Where impurities are present, SO_2 in particular can cause solvent degradation, and coal-fired sources without an FGD would likely need to install one. Filterable PM (fly ash) from coal, if not properly managed, can cause fouling and scale to accumulate on downstream blower fans, heat exchangers, and absorber packing material. Further, additional care in the solvent reclamation is necessary to mitigate solvent degradation that could otherwise occur due to the trace elements that can be present in coal. Because the flue gas from natural gas-fired combustion turbines contains few, if any, impurities that would impact downstream CO_2 capture, the flue gas from natural gas-fired combined cycle EGUs is easier to work with for CO_2 capture, and many of the challenges that were faced by earlier commercial scale demonstrations on coal-fired units can be avoided in the application of CCS at natural gas-fired combustion turbines.

Second, the CO_2 concentration of natural gas-fired combined cycle flue gas is lower than that of coal flue gas (approximately 3-to-4 volume percent for natural gas combined cycle EGUs; 13-to-15 volume percent for coal). For solvent-based CO_2 capture, CO_2 concentration is the driving force for mass transfer and the reaction of CO_2 with the solvent. However, flue gases with lower CO_2 concentrations can be readily addressed by the correct sizing and design of the capture equipment—and such considerations have been made in evaluating the BSER here and are reflected in the cost analysis in VII.C.1.a.ii(A) of this preamble. Moreover, as is detailed in the following sections of the preamble, amine-based CO_2 capture has been shown to be effective at removal of CO_2 from the flue gas of natural gas-fired combined cycle EGUs. In fact, there is not a technical limit to removal of CO_2 from flue gases with low CO_2 concentrations—the EPA notes that amine solvents have been shown to be able to remove CO_2 to concentrations that are less than the concentration of CO_2 in the atmosphere.

Considering these factors, the evidence that underlies the EPA's determination that amine post-combustion CO_2 capture is adequately demonstrated, and that a 90 percent capture standard is achievable, at coal-fired steam generating units, also applies to natural gas-fired combined cycle EGUs. Where differences exist, due to differences in flue gas composition, CCS at natural gas-fired combined cycle combustion turbines will in general face fewer challenges than CCS at coal-fired steam generators.[761] Moreover, in addition to the evidence outlined above, the following sections provide additional information specific to, including examples of, anime-based capture at natural gas-fired combined cycle EGUs. For these reasons, the EPA has determined that CCS at 90 percent capture is adequately demonstrated for natural gas fired combined cycle EGUs.

(1) CO_2 Capture for Combined Cycle Combustion Turbines

As discussed in the preceding, new stationary combustion turbines can use amine-based post-combustion capture. Additionally, new stationary combustion turbines may also utilize oxy-combustion, which uses a purified oxygen stream from an air separation unit (often diluted with recycled CO_2 to control the flame temperature) to combust the fuel and produce a nearly pure stream of CO_2 in the flue gas, as opposed to combustion with oxygen in air which contains 80 percent nitrogen. Currently available post-combustion amine-based CO_2 capture systems require that the flue gas be cooled prior to entering the capture equipment. This holds true for the exhaust from either a coal-fired utility boiler or from a combustion turbine. The most energy efficient way to cool the flue gas stream is to use a HRSG—which, as explained above, is an integral component of a combined cycle turbine system—to generate additional useful output.[762]

CO_2 capture has been successfully applied to an existing combined cycle turbine and several other projects are in development, as discussed immediately below.

(a) CCS on Combined Cycle EGUs

The most prominent example of the use of carbon capture technology on a natural gas-fired combined cycle turbine EGU was at the 386 MW Bellingham Cogeneration Facility in Bellingham, Massachusetts. The plant used Fluor's Econamine FG Plus℠ amine-based CO_2 capture system with a capture capacity of 360 tons of CO_2 per day. The system was used to produce food-grade CO_2 and was in continuous commercial operation from 1991 to 2005 (14 years). The capture system was able to continuously capture 85–95 percent of the CO_2 that would have otherwise been emitted from the flue gas of a 40 MW slip stream.[763] The natural gas combustion flue gas at the facility contained 3.5 volume percent CO_2 and 13–14 volume percent oxygen. As mentioned earlier, the flue gas from a coal combustion flue gas stream has a typical CO_2 concentration of approximately 15 volume percent and more dilute CO_2 stream are more challenging to separate and capture. Just before the CO_2 capture system was shut

[759] The EPA uses the two phrases (i) BSER is CCS with 90 percent capture and (ii) CCS with 90 percent capture is achievable, or similar phrases, interchangeably.

[760] *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[761] Many of the challenges faced by Boundary Dam Unit 3—which proved to be solvable—were caused by the impurities, including fly ash, SO_2, and trace contaminants in coal-fired post-combustion flue gas—which do not occur in the natural gas post-combustion flue gas. As a result, for CO_2 capture for natural gas combustion, flue gas handling is simpler, solvent degradation is easier to prevent, and fewer redundancies may be necessary for various components (*e.g.,* heat exchangers).

[762] The EPA proposed that because the BSER for non-base load combustion turbines was simple cycle technology, CCS was not applicable.

[763] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. *https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.*

down in 2005 (due to high natural gas price), the system had logged more than 120,000 hours of CO_2 capture [764] and had a 98.5 percent on-stream (availability) factor.[765]

The Fluor Econamine FG Plus℠ is a propriety carbon capture solution with more than 30 licensed plants and more than 30 years of operation. This technology uses a proprietary solvent to capture CO_2 from post-combustion sources. The process is well suited to capture CO_2 from large, single-point emission sources such as power plants or refineries, including large facilities with CO_2 capture capacities greater than 10,000 tons per day.[766] On February 6, 2024, Fluor Corporation announced that Chevron New Energies plans to use the Econamine FG Plus℠ carbon capture technology to reduce CO_2 emissions at Chevron's Eastridge Cogeneration combustion turbine facility in Kern County, California. When installed, Fluor's carbon capture solution is expected to reduce the Eastridge Cogeneration facility's carbon emissions by approximately 95 percent.[767]

Moreover, recently, CO_2 capture technology has been operated on NGCC post-combustion flue gas at the Technology Centre Mongstad (TCM) in Norway.[768] TCM can treat a 12 MWe flue gas stream from a natural gas combined cycle cogeneration plant at Mongstad power station. Many different solvents have been operated at TCM including MHI's KS–21™ solvent,[769] achieving capture rates of over 98 percent.

Additionally, in Scotland, the proposed 900 MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. MHI is developing a FEED for the power plant and capture facility.[770] It is anticipated that the power plant will be operational by the end of the 2020s and will have the potential to capture 90 percent of the CO_2 emitting from the combined cycle facility and sequester up to 1.5 million metric tons of CO_2 annually. A storage site being developed 62 miles off the Scottish North Sea coast will serve as a destination for the captured CO_2.[771] [772]

Furthermore, the Global CCS Centre is tracking other international CCS on combustion turbine projects that are in on-going stages of development.[773]

(b) NET Power Cycle

In addition, there are several planned projects using NET Power's Allam-Fetvedt Cycle.[774] The Allam-Fetvedt Cycle is a proprietary process for producing electricity that combusts a fuel with purified oxygen (diluted with recycled CO_2 to control flame temperature) and uses supercritical CO_2 as the working fluid instead of water/steam. This cycle is designed to achieve thermal efficiencies of up to 59 percent.[775] Potential advantages of this cycle are that it emits no NO_X and produces a stream of high-purity CO_2 [776] that can be delivered by pipeline to a storage or sequestration site without extensive processing. A 50 MW (thermal) test facility in La Porte, Texas was completed in 2018 and has since accumulated over 1,500 hours of runtime. There are several announced NET Power commercial projects proposing to use the Allam-Fetvedt Cycle. These include the 280 MW Broadwing Clean Energy Complex in Illinois, and several international projects.

In Scotland, the proposed 900 MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. MHI is developing a FEED for the power plant and capture facility.[777] It is anticipated that the power plant will be operational by the end of the 2020s and will have the potential to capture 90 percent of the CO_2 emitting from the combined cycle facility and sequester up to 1.5 million metric tons of CO_2 annually. A storage site being developed 62 miles off the Scottish North Sea coast will serve as a destination for the captured CO_2.[778] [779]

(c) Coal-Fired Steam Generating Units

As detailed in section VII.C.1.a, CCS has been demonstrated on coal-fired power plants, which provides further support that CCS on base load combined cycle units is adequately demonstrated. Further, 90 percent capture is expected to be, in some ways, more straightforward to achieve for natural gas-fired combined cycle combustion turbines than for coal-fired steam generators. Many of the challenges faced by Boundary Dam Unit 3—which proved to be solvable—were caused by the impurities, including fly ash, SO_2, and trace contaminants in coal-fired post-combustion flue gas. Such impurities naturally occur in coal (sulfur and trace contaminants) or are a natural result of combusting coal (fly ash), but not in natural gas, and thus they do not appear in the natural gas post-combustion flue gas. As a result, for CO_2 capture for natural gas combustion, flue gas handling is simpler, solvent degradation is easier to prevent, and fewer redundancies may be necessary for various components (*e.g.*, heat exchangers).

(d) Other Industry

As discussed in section VII.C.1.a.i.(A)(1) of this preamble, CCS installations in other industries support that capture equipment can achieve 90 percent capture of CO_2 from natural gas-fired base load combined cycle combustion turbines.

(e) EPAct05-Assisted CO_2 Capture Projects at Stationary Combustion Turbines

As for steam generating units, EPAct05-assisted CO_2 capture projects on stationary combustion turbines corroborate that CO_2 capture on gas combustion turbines is adequately demonstrated. Several CCS projects with at least 90 percent capture at commercial-scale combined cycle turbines are in the planning stages. These projects support that CCS with at least 90 percent capture for these units is the industry standard and support the EPA's determination that CCS is adequately demonstrated.

CCS is planned for the existing 550 MW natural gas-fired combined cycle (two combustion turbines) at the Sutter Energy Center in Yuba City, California.[780] The Sutter

[764] *https://boereport.com/2022/08/16/fluor/.*

[765] "Technologies for CCS on Natural Gas Power Systems" Dr. Satish Reddy presentation to USEA, April 2014, *https://usea.org/sites/default/files/event-/Reddy%20USEA%20Presentation%202014.pptx.*

[766] *https://www.fluor.com/market-reach/industries/energy-transition/carbon-capture.*

[767] *https://newsroom.fluor.com/news-releases/news-details/2024/Fluors-Econamine-FG-PlusSM-Carbon-Capture-Technology-Selected-to-Reduce-CO2-Emissions-at-Chevron-Facility/default.aspx.*

[768] *https://netl.doe.gov/carbon-capture/power-generation.*

[769] Mitsubishi Heavy Industries, "Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New KS–21™ Solvent for CO_2 Capture," *https://www.mhi.com/news/211019.html.*

[770] MHI and MHIENG Awarded FEED Contract. *https://www.mhi.com/news/22083001.html.*

[771] Buli, N. (2021, May 10). SSE, Equinor plan new gas power plant with carbon capture in Scotland. *Reuters. https://www.reuters.com/business/sustainable-business/sse-equinor-plan-new-gas-power-plant-with-carbon-capture-scotland-2021-05-11/.*

[772] Acorn CCS granted North Sea storage licenses. September 18, 2023. *https://www.ogj.com/energy-transition/article/14299094/acorn-granted-licenses-for-co2-storage.*

[773] *https://status23.globalccsinstitute.com/.*

[774] The NET Power Cycle was formerly referred to as the Allam-Fetvedt cycle. *https://netpower.com/technology/.*

[775] Yellen, D. (2020, May 25). Allam Cycle carbon capture gas plants: 11 percent more efficient, all CO_2 captured. *Energy Post. https://energypost.eu/allam-cycle-carbon-capture-gas-plants-11-more-efficient-all-co2-captured/.*

[776] This allows for capture of over 97 percent of the CO_2 emissions. *www.netpower.com.*

[780] Calpine Sutter Decarbonization Project, May 17, 2023. *https://www.smud.org/en/Corporate/*

Continued

Decarbonization project will use ION Clean Energy's amine-based solvent technology at a capture rate of 95 percent or more. The project expects to complete a FEED study in 2024 and, prior to being selected by DOE for funding award negotiation, planned commercial operation in 2027. Sutter Decarbonization is one of the projects selected by DOE for funding as part of OCED's Carbon Capture Demonstration Projects program.[781]

The CO_2 capture project at the Deer Park Energy Center in Deer Park, Texas will be designed to capture 95 percent or more of the flue gas from the five combustion turbines at the 1,200 MW natural gas-fired combined cycle power plant, using technology from Shell CANSOLV.[782] The CO_2 capture project already has an air permit issued for the project, which includes a reduction in the allowable emission limits for NO_X from four of the combustion turbines.[783] The CO_2 capture facility will include two quencher columns, two absorber columns, and one stripping column.

The Baytown Energy Center in Baytown, Texas is an existing natural gas-fired combined cycle cogeneration facility providing heat and power to a nearby industrial facility, while distributing additional electricity to the grid. CCS using Shell's CANSOLV solvent is planned for the equivalent of two of the three combustion turbines at the 896 MW natural gas-fired combined cycle power plant, with a capture rate of 95 percent. The CO_2 capture facility at Baytown Energy Center also has an air permit in place, and the permit application provides some details on the process design.[784] The CO_2 capture facility will include two quencher columns, two absorber columns, and one stripping column. To mitigate NO_X emissions, the operation of the SCR systems for the combustion turbines will be adjusted to meet lower NO_X allowable limits—adjustments may include increasing ammonia flow, more frequent SCR repacking and head cleaning, and, possibly, optimization of the ammonia distribution system. The Baytown CO_2 capture project is one of the projects selected by DOE for funding as part of OCED's Carbon Capture Demonstration Projects program.[785] Captured CO_2 will be transported and stored at sites along the U.S. Gulf Coast.

An 1,800 MW natural gas-fired combustion turbine that will be constructed in West Virginia and will utilize CCS has been announced. The project is planned to begin operation later this decade.[786]

There are numerous other EPAct05-assisted projects related to natural gas-fired combined cycle turbines including the following.[787] [788] [789] [790] [791] These projects provide corroborating evidence that capture of at least 90 percent is accepted within the industry.

- General Electric (GE) (Bucks, Alabama) was awarded $5,771,670 to retrofit a combined cycle turbine with CCS technology to capture 95 percent of CO_2 and is targeting commercial deployment by 2030.
- Wood Environmental & Infrastructure Solutions (Blue Bell, Pennsylvania) was awarded $4,000,000 to complete an engineering design study for CO_2 capture at the Shell Chemicals Complex. The aim is to reduce CO_2 emissions by 95 percent using post-combustion technology to capture CO_2 from several plants, including an onsite natural gas CHP plant.
- General Electric Company, GE Research (Niskayuna, New York) was awarded $1,499,992 to develop a design to capture 95 percent of CO_2 from combined cycle turbine flue gas with the potential to reduce electricity costs by at least 15 percent.
- SRI International (Menlo Park, California) was awarded $1,499,759 to design, build, and test a technology that can capture at least 95 percent of CO_2 while demonstrating a 20 percent cost reduction compared to existing combined cycle turbine carbon capture.
- CORMETECH, Inc. (Charlotte, North Carolina) was awarded $2,500,000 to further develop, optimize, and test a new, lower-cost technology to capture CO_2 from combined cycle turbine flue gas and improve scalability to large, combined cycle turbines.
- TDA Research, Inc. (Wheat Ridge, Colorado) was awarded $2,500,000 to build and test a post-combustion capture process to improve the performance of combined cycle turbine flue gas CO_2 capture.
- GE Gas Power (Schenectady, New York) was awarded $5,771,670 to perform an engineering design study to incorporate a 95 percent CO_2 capture solution for an existing combined cycle turbine site while providing lower costs and scalability to other sites.
- Electric Power Research Institute (EPRI) (Palo Alto, California) was awarded $5,842,517 to complete a study to retrofit a 700 MWe combined cycle turbine with a carbon capture system to capture 95 percent of CO_2.
- Gas Technology Institute (Des Plaines, Illinois) was awarded $1,000,000 to develop membrane technology capable of capturing more than 97 percent of combined cycle turbine CO_2 flue gas and demonstrate upwards of 40 percent reduction in costs.
- RTI International (Research Triangle Park, North Carolina) was awarded $1,000,000 to test a novel non-aqueous solvent technology aimed at demonstrating 97 percent capture efficiency from simulated combined cycle turbine flue gas.
- Tampa Electric Company (Tampa, Florida) was awarded $5,588,173 to conduct a study retrofitting Polk Power Station with post-combustion CO_2 capture technology aiming to achieve a 95 percent capture rate.

There are also several announced NET Power Allam-Fetvedt Cycle based CO_2 capture projects that are EPAct05-assisted. These include the 280 MW Coyote Clean Power Project on the Southern Ute Indian Reservation in

Environmental-Leadership/2030-Clean-Energy-Vision/CEV-Landing-Pages/Calpine-presentation.

781 Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

782 Calpine Carbon Capture. *https://calpinecarboncapture.com/wp-content/uploads/2023/05/Calpine-Deer-Park-English.pdf.*

783 Deer Park Energy Center TCEQ Records Online Primary ID 171713.

784 Baytown Energy Center Air Permit TCEQ Records Online Primary ID 172517.

785 Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

786 Competitive Power Ventures (2022). *Multi-Billion Dollar Combined Cycle Natural Gas Power Station with Carbon Capture Announced in West Virginia.* Press Release. September 16, 2022. *https://www.cpv.com/2022/09/16/multi-billion-dollar-combined-cycle-natural-gas-power-station-with-carbon-capture-announced-in-west-virginia/.*

787 General Electric (GE) (2022). *U.S. Department of Energy Awards $5.7 Million for GE-Led Carbon Capture Technology Integration Project Targeting to Achieve 95% Reduction of Carbon Emissions.* Press Release. February 15, 2022. *https://www.ge.com/news/press-releases/us-department-of-energy-awards-57-million-for-ge-led-carbon-capture-technology.*

788 Larson, A. (2022). *GE-Led Carbon Capture Project at Southern Company Site Gets DOE Funding.* Power. *https://www.powermag.com/ge-led-carbon-capture-project-at-southern-company-site-gets-doe-funding/.*

789 U.S. Department of Energy (DOE) (2021). *DOE Invests $45 Million to Decarbonize the Natural Gas Power and Industrial Sectors Using Carbon Capture and Storage.* October 6, 2021. *https://www.energy.gov/articles/doe-invests-45-million-decarbonize-natural-gas-power-and-industrial-sectors-using-carbon.*

790 DOE (2022). *Additional Selections for Funding Opportunity Announcement 2515.* Office of Fossil Energy and Carbon Management. *https://www.energy.gov/fecm/additional-selections-funding-opportunity-announcement-2515.*

791 DOE (2019). *FOA 2058: Front-End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants.* Office of Fossil Energy and Carbon Management. *https://www.energy.gov/fecm/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas.*

Colorado and a 300 MW project located near Occidental's Permian Basin operations close to Odessa, Texas. Commercial operation of the facility near Odessa, Texas is expected in 2028.

(f) Range of Conditions

The composition of natural gas combined cycle post-combustion flue gas is relatively uniform as the level of impurities is, in general, low. There may be some difference in NO_X emissions, but considering the sources are new, it is likely that they will be installed with SCR, resulting in uniform NO_X concentrations in the flue gas. The EPA notes that some natural gas combined cycle units applying CO_2 capture may use exhaust gas recirculation to increase the concentration of CO_2 in the flue gas—this produces a higher concentration of CO_2 in the flue gas. For those sources that apply that approach, the CO_2 capture system can be scaled smaller, reducing overall costs. Considering these factors, the EPA concludes that there are not substantial differences in flue gas conditions for natural gas combined cycle units, and the small differences that could exist would not adversely impact the operation of the CO_2 capture equipment.

As detailed in section VII.C.1.a.i(B)(7), single trains of CO_2 capture facilities have turndown capabilities of 50 percent. Effective turndown to 25 percent of throughputs can be achieved by using 2 trains of capture equipment. CO_2 capture rates have also been shown to be higher at lower throughputs. Moreover, during off-peak hours when electricity prices are lower, additional lean solvent can be produced and held in reserve, so that during high-demand hours, the auxiliary demands to the capture plant stripping column reboiler be reduced. Considering these factors, the capture rate would not be affected by load following operation, and the operation of the combustion turbine would not be limited by turndown capabilities of the capture equipment. As detailed in preceding sections, simple cycle combustion turbines cycle frequently, and have a number of startups and shutdowns per year. However, combined cycle units cycle less frequently and have fewer startups and shutdowns per year. Startups of combined cycle units are faster than coal-fired steam generating units described in section VII.C.1.a.i(B)(7) of the preamble. Cold startups of combined cycle units typically take not more than 3 hours (hot startups are faster), and shutdown takes less than 1 hour. During startup, heat input to the unit is lower to slowly raise the temperature of the HRSG.

Importantly, natural gas post-combustion flue gas does not require the same pretreatment as coal post-combustion flue gas. Therefore, amine solvents are able to capture CO_2 as soon as the flue gas contacts the lean solvent, and startup does not have to wait for operation of other emission controls. Furthermore, there are several different process strategies that can be employed to enable capture during cold startup.[792] [793] These include using an additional reserve of lean solvent (solvent without absorbed CO_2), dedicated heat storage for reboiler preheating, and fast starting steam cycle technologies or high-pressure bypass extraction. Each of these three options has been modeled to show that 95 percent capture rates can be achieved during startup. The first option simply uses a reserve of lean solvent during startup so that capture can occur without needing to wait for the stripping column reboiler to heat up. For hot starts, the startup time of the NGCC is faster, and since the reboiler is already warm, the capture plant can begin operating faster. Shutdowns are short, and high capture efficiencies can be maintained.

Considering that startup and shutdown for natural gas combined cycle units is fast, startups are relatively few, and simple process strategies can be employed so that high capture efficiencies can be achieved during startup, the EPA has concluded that startup and shutdown do not adversely impact the achievable CO_2 capture rate.

Considering the preceding information, the EPA has determined that 90 percent capture is achievable over long periods (*i.e.*, 12-month rolling averages) for base load combustion turbines for all relevant flue gas conditions, variable load, and startup and shutdown.

(g) Summary of Evidence Supporting BSER Determination Without EPAct05-Aassisted Projects

As noted above, under the EPA's interpretation of the EPAct05 provisions, the EPA may not rely on capture projects that received assistance under EPAct05 as the sole basis for a determination of adequate demonstration, but the EPA may rely on those projects to support or corroborate other information that supports such a determination. The information described above that supports the EPA's determination that 90 percent CO_2 capture from natural gas-fired combustion turbines is adequately demonstrated, without consideration of the EPAct05-assisted projects, includes (i) the information concerning coal-fired steam generating units listed in VII.C.1.a.i.(B)(9)[794] (other than the information concerning EPAct05-assisted coal-fired unit projects and the information concerning natural gas-fired combustion turbines); (ii) the information that a 90 percent capture standard is achievable at coal-fired steam generating units, also applies to natural gas-fired combined cycle EGUs (*i.e.*, all the information in VIII.F.4.c.iv.(B) (before (1)) and (1) (before (a)); (iii) the information concerning CCS on combined cycle EGUs (*i.e.*, all the information in VIII.F.4.c.iv.(B)(1)(a)); and (iv) the information concerning Net Power (*i.e.*, all the information in VIII.F.4.c.iv.(B)(1)(b)). All this information by itself is sufficient to support the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated. Substantial additional information from EPAct05-assisted projects, as described in section VIII.F.4.c.iv.(B)(1)(e), provides additional support and confirms that 90 percent CO_2 capture from natural gas-fired combustion turbines is adequately demonstrated.

(2) Transport of CO_2

In section VII.C.1.a.i.(C) of this document, the EPA described its rationale for finalizing a determination that CO_2 transport by pipelines as a component of CCS is adequately demonstrated for use of CCS with existing steam generating EGUs. The Agency's rationale for finalizing the same determination—that CO_2 transport by pipelines as a component of CCS is adequately demonstrated for CCS use with new combustion turbine EGUs—is much the same as that described in section VII.C.1.a.i.(C). As discussed in

[792] *https://ieaghg.org/ccs-resources/blog/new-ieaghg-report-2022-08-start-up-and-shutdown-protocol-for-power-stations-with-co2-capture.*

[793] *https://assets.publishing.service.gov.uk/media/5f95432ad3bf7f35f26127d2/start-up-shut-down-times-power-ccus-main-report.pdf.*

[794] Specifically, this includes the information concerning Boundary Dam, coupled with engineering analysis concerning key improvements that can be implemented in future CCS deployments during initial design and construction (*i.e.*, all the information in section VII.C.1.a.i.(B)(1)(a) and the information concerning Boundary Dam in section VII.C.1.a.i.(B)(1)(b)); (ii) the information concerning other coal-fired demonstrations, including the Argus Cogeneration Plant and AES's Warrior Run (*i.e.*, all the information concerning those sources in section VII.C.1.a.i.(B)(1)(a)); (iii) the information concerning industrial applications of CCS (*i.e.*, all the information in section VII.C.1.a.i.(A)(1); and (iv) the information concerning CO_2 capture technology vendor statements (*i.e.*, all the information in VII.C.1.a.i.(B)(3)).

section VII.C.1.a.i.(C) of this preamble, CO_2 pipelines are available and their network is expanding in the U.S., and the safety of existing and new supercritical CO_2 pipelines is comprehensively regulated by PHMSA.[795] A new combustion turbine may also be co-located with a storage site, so that minimal transport of the CO_2 is required.

Pipeline transport of CO_2 captured from newly constructed or reconstructed natural gas-fired combustion turbine EGUs meets the BSER requirements based on the same evidence, and for the same reasons, as does pipeline transport of CO_2 captured from existing coal-fired steam generating EGUs, as described in section VII.C.1.a.i.(C) of this preamble. This is because the CO_2 that is captured from a natural gas-fired turbine, compressed, and delivered into a pipeline is indistinguishable from the CO_2 that is captured from an existing coal-fired steam generating unit. Accordingly, all the evidence and explanation in section VII.C.1.a.i.(C) of this preamble that it is adequately demonstrated, cost-effective, and consistent with the other BSER factors for an existing coal-fired steam generating unit to construct a lateral pipeline from its facility to a sequestration site applies to new natural gas-fired turbines. This includes the history of CO_2 pipeline build-out (VII.C.1.a.i.(C)(1)), the recent examples of new pipelines (VII.C.1.a.i.(C)(1)(b)), EPAct05-assisted CO_2 pipelines for CCS (VII.C.1.a.i.(C)(1)(c)), the network of existing and planned CO_2 trunklines (VII.C.1.a.i.(C)(1)(d)), permitting and rights of way considerations (VII.C.1.a.i.(C)(2)), and considerations of the security of CO_2 transport, including PHMSA requirements (VII.C.1.a.i.(C)(3)).

The only difference between pipeline transport for the coal-fired steam generation and the gas-fired turbines is that the coal-fired units are already in existence and, as a result, the location and length of their pipelines, as needed to transport their CO_2 to nearby sequestration, is already known, whereas new gas-fired turbines are not yet sited. We discuss the implications for new gas-fired turbines in the next section.

(3) Geologic Sequestration of CO_2

In section VII.C.1.a.i.(D) of this document, the EPA described its rationale for finalizing a determination that geologic sequestration (*i.e.*, the long-term containment of a CO_2 stream in subsurface geologic formations) is adequately demonstrated as a component of the use of CCS with existing coal-fired steam generating EGUs. Similar to the previous discussion regarding CO_2 transport, the Agency's rationale for finalizing a determination that geologic sequestration is adequately demonstrated as a component of the use of CCS with new combustion turbine EGUs is the same as described in VII.C.1.a.i.(D) for existing coal-fired steam generating EGUs. The storage/sequestration sites used to store captured CO_2 from existing coal-fired EGUs could also be used to store captured CO_2 from newly constructed or reconstructed combustion turbine EGUs. All of the considerations and challenges associated with developing geologic storage sites for existing sources are also considerations and challenges associated with developing such sites for newly constructed or reconstructed sources.

(a) In General

Geologic sequestration (*i.e.*, the long-term containment of a CO_2 stream in subsurface geologic formations) is well proven. Deep saline formations, which may be evaluated and developed for CO_2 sequestration are broadly available throughout the U.S. Geologic sequestration requires a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. As discussed in section VII.C.1.a.i.(D) of this preamble, there have been numerous instances of geologic sequestration in the U.S. and overseas, and the U.S. has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. This regulatory framework includes the UIC well regulations, which are under the authority of the SDWA, and the GHGRP, under the authority of the CAA.

Geologic settings which may be suitable for geologic sequestration of CO_2 are widespread and available throughout the U.S. Through an availability analysis of sequestration potential in the U.S. based on resources from the DOE, the USGS, and the EPA, the EPA found that there are 43 states with access to, or are within 100 km from, onshore or offshore storage in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs.

All of the evidence and explanation that geological sequestration of CO_2 is adequately demonstrated and meets the other BSER factors that the EPA described with respect to sequestration of CO_2 from existing coal-fired steam generating units in section VII.C.1.a.i.(D) of this preamble apply with respect to CO_2 from new natural gas-fired combustion turbines. Sequestration is broadly available (VII.C.1.a.i.(D)(1)(a)). It is adequately demonstrated, with many examples of projects successfully injecting and containing CO_2 in the subsurface (VII.C.1.a.i.(D)(2)). It provides secure storage, with a detailed set of regulatory requirements to ensure the security of sequestered CO_2, including the UIC well regulations pursuant to SDWA authority, and the GHGRP pursuant to CAA authority (VII.C.1.a.i.(D)(4)). The EPA has the experience to properly regulate and review permits for UIC Class VI injection wells, has made considerable improvements to its permitting process to expedite permitting decisions, and has granted several states primacy to issue permits, and is supporting that state permitting (VII.C.1.a.i.(D)(5)).

(b) New Natural Gas-Fired Combustion Turbines

As discussed in section VII.C.1.a.i.(D)(1), deep saline formations that may be considered for use in geologic sequestration (or storage) are common in the continental United States. In addition, there are numerous unmineable coal seams and depleted oil and gas reserves throughout the country that could potentially be utilized as sequestration sites. The DOE estimates that areas of the U.S. with appropriate geology have a sequestration potential of at least 2,400 billion to over 21,000 billion metric tons of CO_2 in deep saline formations, unmineable coal seams, and oil and gas reservoirs. The EPA's scoping assessment found that at least 37 states have geologic characteristics that are amenable to deep saline sequestration and identified an additional 6 states are within 100 kilometers of potentially amenable deep saline formations in either onshore or offshore locations. In terms of land area, 80 percent of the continental U.S. is within 100 km of deep saline formations.[796] While the EPA's geographic availability analyses focus on deep saline formations, other geologic formations such as unmineable coal seams or depleted oil and gas

[795] PHMSA additionally initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of CO_2 pipelines following investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020. For more information, see: *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[796] For additional information on CO_2 transportation and geologic sequestration availability, please see EPA's final TSD, *GHG Mitigation Measures for Steam Generating Units.*

reservoirs represent potential additional CO_2 storage options. Therefore, we expect that the vast majority of new base load combustion turbine EGUs could be sited within 100 km of a sequestration site.

While the potential for some type of sequestration exists in large swaths of the continental U.S., we recognize that there are a few states that do not have geologic conditions suitable for geologic sequestration within or near their borders. If an area does not have a suitable geologic sequestration site, then a utility or project developer seeking to build a new combustion turbine EGU for base load generation has two options—either (1) the new EGU may be located near the electricity demand and the CO_2 transported via a CO_2 pipeline to a geologic sequestration site, or (2) the new EGU may be located closer to a geologic sequestration site and the electricity delivered to customers through transmission lines. Regarding option 1, as discussed in VII.C.1.a.i(C), the EPA believes that both new and existing EGUs are capable of constructing CO_2 pipelines as needed. With regard to option 2, we expect that this option may be preferred for projects where a CO_2 pipeline of substantial length would be required to reach the sequestration site. However, we note that for new base load combustion turbine EGUs, project developers have flexibility with regard to siting such that they can balance whether to site a new unit closer to a potential geologic sequestration site or closer to a load area depending on their specific needs.

Electricity demand in areas that may not have geologic sequestration sites may be served by gas-fired EGUs that are built in areas with geologic sequestration, and the generated electricity can be delivered through transmission lines to the load areas through ‘‘gas-by-wire.’’ An analogous approach, known as ‘‘coal-by-wire’’ has long been used in the electricity sector for coal-fired EGUs because siting a coal-fired EGU near a coal mine and transmitting the generated electricity long distances to the load area is sometimes less expensive than siting the coal EGU near the load area and shipping the coal long distances. The same principle may apply to new base load combustion turbine EGUs such that it may be more practicable for an project developer to site a new base load combustion turbine EGU in a location in close proximity to a geologic sequestration site and to deliver the electricity generated through transmission lines to the load area rather than siting the new gas-fired combustion turbine EGU near the load area and building a lengthy pipeline to the geologic sequestration site.

Gas-by-wire and coal-by-wire are possible due to the electricity grid's extensive high voltage transmission networks that enable electricity to be transmitted over long distances. See the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units*, which is available in the rulemaking docket for this action. In many of the areas without reasonable access to geologic sequestration, utilities, electric cooperatives, and municipalities have a history of joint ownership of electricity generation outside the region or contracting with electricity generation in outside areas to meet demand. Some of the areas are in Regional Transmission Organizations (RTOs),[797] which engage in planning as well as balancing supply and demand in real time throughout the RTO's territory. Accordingly, generating resources in one part of the RTO can serve load in other parts of the RTO, as well as load outside of the RTO.

In the coal context, there are many examples of where coal-fired power generation in one state has been used to supply electricity in other states. For example, the Prairie State Generating Plant, a 2-unit 1,600 MW coal-fired power plant in Illinois that is currently considering retrofitting with CCS, serves load in eight different states from the Midwest to the mid-Atlantic.[798] The Intermountain Power Project, a coal-fired plant located in Delta, Utah, that is converting to co-fire hydrogen and natural gas, serves customers in both Utah and California.[799] Additionally, historically nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah. Further, Idaho Power, which serves customers in Idaho and eastern Oregon has met demand in part from power generating at coal-fired power plants located in Wyoming and Nevada. This same concept of siting generation in one location to serve demand in another area and using existing transmission infrastructure to do so could similarly be applied to gas-fired combustion turbine power plants, and, in fact, there are examples of gas-fired combustion turbine EGUs serving demand more than 100 km away from where they are sited. For example, Portland General Electric's Carty Generating Station, a 436–MW NGCC unit located in Boardman, Oregon[800] serves demand in Portland, Oregon,[801] which is approximately 270 km away from the source.

In the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units*, we explore in detail the potential for gas-by-wire and the ability of demand in areas without geologic sequestration potential to be served by gas generation located in areas that have access to geologic sequestration. As discussed in the memorandum, the vast majority of the United States is within 100 km of an area with geologic sequestration potential. A review of our scoping assessment indicates that there are limited areas of the country that are not within 100 km of a potential deep saline sequestration formation (although some of these areas may be within 100 km of an unmineable coal seam or depleted oil and gas reservoir that could potentially serve as a sequestration site). In many instances, these areas include areas with low population density, areas that are already served by transmission lines that could deliver gas-by-wire, and/or include areas that have made policy or other decisions not to pursue a resource mix that includes new NGCC due to state renewable portfolio standards or for other reasons.

In many of these areas, utilities, electric cooperatives, and municipalities have a history of obtaining electricity from generation in outside areas to meet demand. Some of the relevant areas are in an RTO or ISO, which operate the transmission system and dispatch generation to balance supply and demand regionwide, as well as engage in regionwide planning and cost allocation to facilitate needed transmission development. Accordingly, generating resources in one part of an RTO/ISO, such as through an NGCC plant, can serve loads in other parts of the RTO/ISO, as well as serving load areas outside of the RTO/ISO. As we consider each of these geographic areas in the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units*, we make key points as to why this final rule does not negatively impact the ability of these regions to access new NGCC generation to the extent that NGCC generation is needed to supply demand and/or those regions

[797] In this discussion, the term RTO indicates both ISOs and RTOs.

[798] *https://prairiestateenergycampus.com/about/ownership/.*

[799] *https://www.ipautah.com/participants-services-area/.*

[800] Portland General Electric, ‘‘Our Power Plants,’’ *https://portlandgeneral.com/about/who-we-are/how-we-generate-energy/our-power-plants.*

[801] See George Plaven, ‘‘PGE power plant rising in E. Oregon,’’ The Columbian (October 10, 2015, 5:55 a.m.), *https://www.columbian.com/news/2015/oct/10/pge-power-plant-rising-in-e-oregon/.* See also Portland General Electric, ‘‘PGE Service Area,’’ *https://portlandgeneral.com/about/info/service-area.*

want to include new NGCC generation in their resource mixes.

(C) Costs

The EPA has evaluated the costs of CCS for new combined cycle units, including the cost of installing and operating CO_2 capture equipment as well as the costs of transport and storage. The EPA has also compared the costs of CCS for new combined cycle units to other control costs, in part derived from other rulemakings that the EPA has determined to be cost-reasonable, and the costs are comparable. Based on these analyses, the EPA considers the costs of CCS for new combined cycle units to be reasonable. Certain elements of the transport and storage costs are similar for new combustion turbines and existing steam generating units. In this section, the EPA outlines these costs and identifies the considerations specific to new combustion turbines. These costs are significantly reduced by the IRC section 45Q tax credit.

(1) Capture Costs

According to the NETL Fossil Energy Baseline Report (October 2022 revision), before accounting for the IRC section 45Q tax credit for sequestered CO_2, using a 90 percent capture amine-based post-combustion CO_2 capture system increases the capital costs of a new combined cycle EGU by 115 percent on a $/kW basis, increases the heat rate by 13 percent, increases incremental operating costs by 35 percent, and derates the unit (*i.e.*, decreases the capacity available to generate useful output) by 11 percent.[802] For a base load combustion turbine, carbon capture increases the LCOE by 62 percent (an increase of 27 $/MWh) and has an estimated cost of $81/ton ($89/metric ton) of onsite CO_2 reduction.[803] The NETL costs are based on the use of a second-generation amine-based capture system without exhaust gas recirculation (EGR) and, as discussed below, do not take into account further cost reductions that can be expected to occur from efficiency improvements as post-combustion capture systems are more widely deployed, as well as potential technological developments.[804]

The flue gas from natural gas-fired combined cycle turbine differs from that of coal-fired EGUs in several ways that impact the cost of CO_2 capture. These include that the CO_2 concentration in the flue gas is approximately one-third of that observed at coal-fired EGUs, the volumetric flow rate on a per MW basis is larger, and the oxygen concentration is approximately 3 times that of a coal-fired EGU. While the higher amount of excess oxygen has the potential to reduce the efficiency of amine-based solvents that are susceptible to oxidation, natural gas post-combustion flue gas does not have other impurities (SO_2, PM, trace metals) that are present and must be managed in coal flue gas. Other important factors include that the lower concentrations of CO_2 reduce the efficiency of the capture process and that the larger volumetric flow rates require a larger CO_2 absorber, which increases the capital cost of the capture process. Exhaust gas recirculation (EGR), also referred to as flue gas recirculation (FGR), is a process that addresses all these issues. EGR diverts some of the combustion turbine exhaust gas back into the inlet stream for the combustion turbine. Doing so increases the CO_2 concentration and decreases the O_2 concentration in the exhaust stream and decreases the flow rate, producing more favorable conditions for CCS. One study found that EGR can decrease the capital costs of a combined cycle EGU with CCS by 6.4 percent, decrease the heat rate by 2.5 percent, decrease the LCOE by 3.4 percent, and decrease the overall CO_2 capture costs by 11 percent relative to a combined cycle EGU without EGR.[805] The EPA notes that the NETL costs on which the EPA bases its cost calculations for combined cycle CCS do not assume the use of EGR, but as discussed below, EGR use is plausible and would reduce those costs.

While the costs considered in the preceding are based on the current costs of CCS, the EPA notes that the costs of capture systems can be expected to decrease over the rest of this decade and continue to decrease afterwards.[806] As part of the plan to reduce the costs of CO_2 capture, the DOE is funding multiple projects to further advance CCS technology from various point sources, including combined cycle turbines, cement manufacturing plants, and iron and steel plants.[807] It should be noted that some of these projects may be EPAct05-assisted. The general aim is to lower the costs of the technologies, and to increase investor confidence in the commercial scale applications, particularly for newer technologies or proven technologies applied under unique circumstances. In particular, OCED's Carbon Capture Demonstration Projects are targeted to accelerate continued power sector carbon capture commercialization through reducing costs and reducing uncertainties to project development. These cost and uncertainty reductions arise from reductions in cost of capital, increases in system scale, standardization and reduction in non-recurring engineering costs, maturation of supply chain ecosystem, and improvements in engineering design and materials over time.[808]

Although current post-combustion CO_2 capture projects have primarily been based on amine capture systems, there are multiple alternate capture technologies in development—many of which are funded through industry research programs—that could yield reductions in capital, operating, and auxiliary power requirements and could reduce the cost of capture significantly or improve performance. More specifically, post combustion carbon capture systems generally fall into one of several categories: solvents, sorbents, membranes, cryogenic, and molten carbonate fuel cells[809] systems. It is

[802] CCS reduced the net output of the NETL F class combined cycle EGU from 726 MW to 645 MW.

[803] Although not our primary approach to assessing costs in this final rule, for consistency with the proposal's assumption capacity factor, these calculations use a service life of 30 years, an interest rate of 7.0 percent, a natural gas price of $3.61/MMBtu, and a capacity factor of 65 percent. These costs do not include CO_2 transport, storage, or monitoring costs.

[804] Recent DOE analysis has compared the NETL costs with more recent FEED study costs and expert interviews and determined they are consistent after accounting for differences in inflation, economic assumptions, and other technology details. *Portfolio Insights: Carbon Capture in the Power Sector,* DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[805] Energy Procedia. (2014). *Impact of exhaust gas recirculation on combustion turbines. Energy and economic analysis of the CO_2 capture from flue gas cf combined cycle power plants. https://www.sciencedirect.com/science/article/pii/S1876610214001234.*

[806] For example, see the article *CCUS Market Outlook 2023: Announced Capacity Soars by 50%,* which states, "New gas power plants with carbon capture, for example, could be cheaper than unabated power in Germany as early as next year when coupled with the carbon price." *https://about.bnef.com/blog/ccus-market-outlook-2023-announced-capacity-soars-by-50/.*

[807] The DOE has also previously funded FEED studies for natural gas-fired combined cycle turbine facilities. These include FEED studies at existing combined cycle turbine facilities at Panda Energy Fund in Texas, Elk Hills Power Plant in Kern County, California, Deer Park Energy Center in Texas, Delta Energy Center in Pittsburg, California, and utilization of a Piperazine Advanced Stripper (PZAS) process for CO_2 capture conducted by The University of Texas at Austin.

[808] *Portfolio Insights: Carbon Capture in the Power Sector* report. DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[809] Molten carbonate fuel cells are configured for emissions capture through a process where the flue gas from an EGU is routed through the molten carbonate fuel cell that concentrates the CO_2 as a side reaction during the electric generation process

expected that as CCS infrastructure increases, technologies from each of these categories will become more economically competitive. For example, advancements in solvents that are potentially direct substitutes for current amine-solvents will reduce auxiliary energy requirements and reduce both operating and capital costs, and thereby, increase the economic competitiveness of CCS.[810] Planned large-scale projects, pilot plants, and research initiatives will also decrease the capital and operating costs of future CCS technologies.

In general, CCS costs have been declining as carbon capture technology advances.[811] While the cost of capture has been largely dependent on the concentration of CO_2 in the gas stream, advancements in varying individual CCS technologies tend to drive down the cost of capture for other CCS technologies. The increase in CCS investment is already driving down the costs of near-future CCS technologies. The Global CCS Institute has tracked publicly available information on previously studied, executed, and proposed CO_2 capture projects.[812] The cost of CO_2 capture from low-to-medium partial pressure sources such as coal-fired power generation has been trending downward over the past decade, and is projected to fall by 50 percent by 2025 compared to 2010. This is driven by the familiar learning-processes that accompany the deployment of any industrial technology. A review of learning rates (the reduction in cost for a doubling of production or capacity) for various energy related technologies similar to carbon capture (flue gas desulfurization, selective catalytic reduction, combined cycle turbines, pulverized coal boilers, LNG production, oxygen production, and hydrogen production via steam methane reforming) demonstrated learning rates of 5 percent to 27 percent for both capital expenditures and operations and maintenance costs.[813] [814] Studies of the cost of capture and compression of CO_2 from power stations completed 10 years ago averaged around $95/metric ton ($2020). Comparable studies completed in 2018/2019 estimated capture and compression costs could fall to approximately $50/metric ton CO_2 by 2025. Current target pricing for announced projects at coal-fired steam generating units is approximately $40/metric ton on average, compared to Boundary Dam whose actual costs were reported to be $105/metric ton, noting that these estimates do not include the impact of the 45Q tax credit as enhanced by the IRA. Additionally, IEA suggests this trend will continue in the future as technology advancements ‘‘spill over’’ into other projects to reduce costs.[815] Similarly, EIA incorporates a minimum 20 percent reduction in carbon capture and sequestration costs by 2035 in their Annual Energy Outlook 2023 modeling in part to account for the impact of spillover and international learning.[816] The Annual Technology Baseline published by NREL with input from NETL projects a 10 percent reduction in capital expenditures from 2021 through 2032 in the ‘‘Conservative Technology Innovation Scenario’’ for natural gas carbon capture retrofit projects, under the assumption that only learning processes lead to future cost reductions and that there are no additional improvements from investments in targeted technology research and development.[817] In a recent case study of the cost and performance of carbon capture retrofits on existing natural gas combined cycle units, based on discussions with external technology providers, engineering consultants, asset developers, and applicants for DOE awards, DOE used a 25 percent capital cost reduction estimate to illustrate the potential future capital costs of an Nth-of-a-Kind facility, as well as ‘‘conservatively model[ing]’’ operating expense reductions at 1 percent, for a combined overall decrease in the levelized cost of energy of about 10 percent for the Nth-of-a-Kind facility compared to a First-of-a-Kind facility.[818] DOE further found this illustrative cost reduction estimate from learning through doing to be consistent with other studies that use hybrid engineering-economic and experience-curve approaches to estimate potential decreases in the levelized cost of energy of 10–11 percent for Nth-of-a-Kind plants compared with First-of-a-Kind plants.[819] [820] Policies in the IIJA and IRA are further increasing investment in CCS technology that can accelerate the pace of innovation and deployment.

(2) CO_2 Transport and Sequestration Costs

NETL's ‘‘Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies’’ provides an estimation of transport costs based on the CO_2 Transport Cost Model.[821] The CO_2 Transport Cost Model estimates costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operations and maintenance costs.

NETL's Quality Guidelines also provide an estimate of sequestration costs. These costs reflect the cost of site screening and evaluation, permitting and construction costs, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection. Permitting and construction costs also reflect the regulatory requirements of the UIC Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations. NETL calculates these sequestration costs on the basis of generic plant locations in the Midwest, Texas, North Dakota, and Montana, as described in the NETL energy system studies.[822]

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in the fuel cell. FuelCell Energy, Inc. (2018). *SureSource Capture. https://www.fuelcellenergy.com/recovery-2/suresource-capture/.*

[810] DOE. *Carbon Capture, Transport, & Storage. Supply Chain Deep Dive Assessment.* February 24, 2022. *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf.*

[811] International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions—A new era for CCUS. https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus.* The same is true for CCS on coal-fired EGUs.

[812] Technology Readiness and Costs of CCS (2021). Global CCS Institute. *https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf.*

[813] *https://www.sciencedirect.com/science/article/pii/S1750583607000163.*

[814] As an additional example for cost reductions from learning processes via deployment achieved in other complex power generation projects, the most recent sustained deployment of 19 nuclear reactors in South Korea from 1989 through 2008 resulted in a 13 percent reduction in capital costs. *https://www.sciencedirect.com/science/article/pii/S0301421516300106.*

[815] International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions—CCUS technology innovation. https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus.*

[816] Energy Information Administration (EIA) (2023). *Assumptions to the Annual Energy Outlook 2023: Electricity Market Module. https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.*

[817] National Renewable Energy Laboratory (NREL) (2023). *Annual Technology Baseline 2023. https://atb.nrel.gov/electricity/2023/fossil_energy_technologies.*

[818] *Portfolio Insights: Carbon Capture in the Power Sector.* DOE. 2024. *https://www.energy.gov/oced/portfolio-strategy.*

[819] *https://www.frontiersin.org/articles/10.3389/fenrg.2022.987166/full.*

[820] *https://www.sciencedirect.com/science/article/pii/S1750583607000163.*

[821] Grant, T., *et al.* ‘‘Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies.’’ National Energy Technology Laboratory. 2019. *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[822] National Energy Technology Laboratory (NETL), ‘‘FE/NETL CO2 Saline Storage Cost Model (2017),’’ U.S. Department of Energy, DOE/NETL–2018–1871, 30 September 2017. *https://netl.doe.gov/energy-analysis/details?id=2403.*

There are two primary cost drivers for a CO_2 sequestration project: the rate of injection of the CO_2 into the reservoir and the areal extent of the CO_2 plume in the reservoir. The rate of injection depends, in part, on the thickness of the reservoir and its permeability. Thick, permeable reservoirs provide for better injection and fewer injection wells. The areal extent of the CO_2 plume depends on the sequestration capacity of the reservoir. Thick, porous reservoirs with a good sequestration coefficient will present a small areal extent for the CO_2 plume and have lower testing and monitoring costs. NETL's Quality Guidelines model costs for a given cumulative storage potential.[823]

In addition, provisions in the IIJA and IRA are expected to significantly increase the CO_2 pipeline infrastructure and development of sequestration sites, which, in turn, are expected to result in further cost reductions for the application of CCS at a new combined cycle EGUs. The IIJA establishes a new Carbon Dioxide Transportation Infrastructure Finance and Innovation program to provide direct loans, loan guarantees, and grants to CO_2 infrastructure projects, such as pipelines, rail transport, ships and barges.[824] The IIJA also establishes a new Regional Direct Air Capture Hubs program which includes funds to support four large-scale, regional direct air capture hubs and more broadly support projects that could be developed into a regional or inter-regional network to facilitate sequestration or utilization.[825] DOE is additionally implementing IIJA section 40305 (Carbon Storage Validation and Testing) through its CarbonSAFE initiative, which aims to further development of geographically widespread, commercial-scale, safe storage.[826] The IRA increases and extends the IRC section 45Q tax credit, discussed next.

(3) IRC Section 45Q Tax Credit

For the reasons explained in section VII.C.1.a.ii of this preamble, in determining the cost of CCS, the EPA is taking into account the tax credit provided under IRC section 45Q, as revised by the IRA. The tax credit is available at \$85/metric ton (\$77/ton) and offsets a significant portion of the capture, transport, and sequestration costs noted above.

(4) Total Costs of CCS

In a typical NSPS analysis, the EPA amortizes costs over the expected operating life of the affected facility and assumes constant revenue and expenses over that period of time. For a new combustion turbine, the expected operating life is 30 years. The EPA has adjusted that analysis in this rule to account for the fact that the IRC section 45Q tax credit is available for only the 12 years after operation is commenced. Since the duration of the tax credit is less than the expected life of a new base load combustion turbine, the EPA conducted the costing analysis by recognizing that the substantial revenue available for sequestering CO_2 during the first 12 years of operation is expected to result in higher capacity factors for that period, and the potential higher operating costs during the subsequent 18 years when the 45Q tax credit is not available is likely to result in lower capacity factors (see final TSD, *Greenhouse Gas Mitigation Measures, Carbon Capture and Storage for Combustion Turbines* for more discussion).[827] [828]

Specifically, the EPA's cost analysis assumes that the combined cycle turbine operates at a capacity of 80 percent over the initial 12-year period. This capacity level is generally consistent with the IPM model projections of 87 percent (and, in fact, somewhat more conservative). The 80 percent capacity factor assumption is also less than the 85 percent capacity factor assumption in the NETL analysis.[829] But notably, the higher capacity factors in the IPM analysis and in the NETL analysis suggest that higher capacity factors may be reasonable and as figure 8 in the final TSD, *Greenhouse Gas Mitigation Measures, Carbon Capture and Storage for Combustion Turbines* demonstrates, would result in even lower costs. The analysis further assumes that the turbine operates at a capacity of 31 percent during the remaining 18-year period. As explained in the final TSD, *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines,* to avoid impacting the compliance costs due to changes in the overall capacity factors with the base case, the EPA kept the overall 30-year capacity factor at the historical average of 51 percent. The EPA evaluated several operational scenarios (as described in the TSD). The scenario with an initial 12-year capacity factor of 80 percent and a subsequent 18-year capacity factor of 31 percent (for a 30-year capacity factor of 51 percent) represents the primary policy case. It should be noted that at a 31 percent capacity factor, the combustion turbine would be subcategorized as an intermediate load combustion turbine, and therefore would be subject to a less stringent standard of performance that is based on efficient operation, not on the use of CCS.

This costing approach results in lower compliance costs than assuming a constant capacity factor for the 30-year useful life of the turbine because of increased revenue from generation during the initial 12-year period, increased revenue from the IRC section 45Q tax credits during that period, and lower costs during the last 18 years when the tax credit is not available. As noted, this is a reasonable approach because the economic incentive provided by the tax credit is so significant on a \$/ton basis that the EPA expects sources to dispatch at higher levels while the tax credit is in effect.

The EPA calculated two sets of CCS costs: the first assumes that the turbine continues to operate the capture system during the last 18 years, and the second assumes that the turbine does not operate the capture system during the last 18 years.[830] Assuming continued operation of the capture equipment, the compliance costs are \$15/MWh and \$46/ton (\$51/metric ton) for a 6,100 MMBtu/h H-Class turbine, which has a net output of approximately 990 MW; and \$19/MWh and \$57/ton (\$63/metric ton) for a 4,600 MMBtu/h F-Class turbine, which has a net output of

[823] Department of Energy. Regional Direct Air Capture Hubs. (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[824] DOE. Carbon Dioxide Transportation Infrastructure. *https://www.energy.gov/lpo/carbon-dioxide-transportation-infrastructure.*

[825] Department of Energy. "Regional Direct Air Capture Hubs." (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[826] For more information, see the NETL announcement. *https://www.netl.doe.gov/node/12405.*

[827] In the proposal, the EPA used a constant 65 percent capacity factor, representative of the initial capacity factor of recently constructed combined cycle turbines, and effective 30-year 45Q tax credit of \$41/ton. For this final rule, the EPA considers the approach of using a higher capacity factor for the first 12 years and a lower one for the last 18 years to reflect more accurately actual operating conditions, and therefore to be a more realistic basis for calculating CCS costs.

[828] The EPA's cost approach for CCS for existing coal-fired units also assumed that those units would increase their capacity during the 12-year period when the 45Q tax credit was available. See preamble section VII.C.1.a.ii, and *Greenhouse Gas Mitigation Measures for Steam Generating Units* TSD section 4.7.5. Because coal-fired power plants are existing plants, the EPA calculated CCS costs by assuming a 12-year amortization period for the CCS equipment, and the EPA did not need to make any assumptions about the operation of the coal-fired unit after the 12-year period.

[829] Compliance costs would be lower if higher capacity factors were used during the first 12 years of operation.

[830] The CCS and CO_2 TS&M costs are amortized over the period the equipment is operated—30 years or 12 years.

approximately 700 MW.[831] [832] If the capture system is not operated while the combustion turbine is subcategorized as an intermediate load combustion turbine, the compliance costs are reduced to $8/MWh and $43/ton ($47/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $12/MWh and $60/ton ($66/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. All of these costs are comparable to the cost metrics that, based on prior rules, the EPA finds to be reasonable in this rulemaking.[833] For a more detailed discussion of costs, see the TSD—*GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* section 2.3, Figure 12a.

The EPA considers these CCS cost estimates to be conservatively high because they do not take into account cost improvements from the potential use of exhaust gas recirculation, which, according to one study, could lower LCOE by 3.4 percent, as described in preamble section VIII.F.4.c.iv.(C)(1). Nor do they consider the potential for additional efficiency improvements for combined cycle units[834] or CCS technological advances, as discussed in preamble section VIII.F.4.c.iv.(B)(1)(b), VIII.F.4.c.iv.(C)(1), and RTC section 3.1. The EPA considers that at least some of these cost improvements are likely. Accordingly, the EPA also calculated the CCS costs based on an assumed 5 percent reduction in costs, in order to approximate these likely improvements, as follows: Assuming continued operation of the capture equipment, the compliance costs are $13/MWh and $40/ton ($44/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $18/MWh and $54/ton ($59/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. If the capture system is not operated while the combustion turbine is subcategorized as in intermediate load combustion turbine, the compliance costs are reduced to $8/MWh and $39/ton ($43/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $11/MWh and $56/ton ($61/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine.

In addition, the EPA considers all those costs to be conservative (in favor of higher costs) because they assume that the combustion turbine operator will not receive any revenues from captured CO_2 after the 12-year period for the tax credit. In fact, it is plausible that there will be sources of revenue, potentially including from the sale of the CO_2 for utilization and credits to meet state or corporate clean energy goals, as discussed in RTC section 2.2.4.3.

It should be noted that natural gas-fired combustion turbines with CCS may well generate at higher capacity factors after the expiration of the 45Q tax credit than the EPA's above-described BSER cost analysis assumes. In fact, the EPA's IPM model projects that the natural gas combined cycle generation that is projected to install CCS in the illustrative final rule scenario operates at an average 73 percent capacity factor, due to existing state regulatory requirements, during the 2045 model year, which is after the expiration of the 45Q tax credit. In addition, as discussed in RTC section 2.2.4.3, it is plausible that following the 12-year period of the tax credit, by the 2040s, cost improvements in CCS operations, more widespread adoption of CO_2 emission limitation requirements in the electricity sector, and greater demand for CO_2 for beneficial uses will support continued operation of fossil fuel-fired generation with CCS. Accordingly, the EPA also calculated CCS costs assuming that new F-Class and H-Class combustion turbines with CCS generate at a constant capacity factor of at least 60 percent, and up to 80 percent, during their 30-year useful life. In this calculation, the EPA amortized the costs of CCS over the 30-year useful life of the turbine. The EPA includes these costs in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* section 2.3, Figure 8.[835] At the lower levels of capacity, costs are higher than described above (which assumed 80 percent capacity during the first 12 years), but even at those lower levels, the costs are broadly consistent with the cost-reasonable metrics based on prior rules, particularly when those costs are reduced by an additional 5 percent to account for improved efficiency and other factors, as noted above. Nonetheless, consistent with the EPA's commitment to review, and if appropriate, revise the emission guidelines for coal-fired steam generating units as discussed in section VII.F, the EPA also intends to evaluate, by 2041, the continued cost-reasonableness of CCS for natural gas-fired combustion turbines in light of these potential significant developments, and will consider at that time whether a future regulatory action may be appropriate.

(5) Comparison to Other Costs of Controls

The costs for CCS applied to a representative new base load stationary combustion turbine EGU are generally lower than the costs of other controls in EPA rules for fossil fuel-fired electric generating units, as well as the costs of other controls for greenhouse gases, as described in section VII.C.1.a.ii(D), which supports the EPA's view that the CCS costs are reasonable.

(D) Non-Air Quality Health and Environmental Impact and Energy Requirements

In this section of the preamble, the EPA considers the non-air quality health and environmental impacts of CCS for new combined cycle turbines and concludes there are limited consequences related to non-air quality health and environmental impact and energy requirements. The EPA first discusses energy requirements, and then considers non-GHG emissions impacts and water use impacts, resulting from the capture, transport, and sequestration of CO_2.

With respect to energy requirements, including a 90 percent or greater carbon capture system in the design of a new combined cycle turbine will increase the unit's parasitic/auxiliary energy demand and reduce its net power output. A utility that wants to construct a combined cycle turbine to provide 500 MWe-net of power could build a

[831] The output of the H-Class model combined cycle EGU without CCS is 992 MW. The auxiliary load of CCS reduces the net out to 883 MW. The output of the F-Class model combined cycle EGU without CCS is 726 MW. The auxiliary load of CCS reduces the net out to 645 MW.

[832] As we explain in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* sections 2.3–2.5, the 6,100 MMBtu/h H-Class combustion turbine is the median size of recently constructed combined cycle facilities and the 4,600 MMBtu/h F-Class combustion turbine approximates the size of a number of recently constructed combined cycle facilities as well. CCS costs for smaller sources are higher but are not prohibitive. *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines* TSD, section 2.3, Figures 12a and 13. As noted in RTC section 3.1, we expect costs to decrease due to learning by doing and technological development. In addition, since the incremental generating costs of larger more efficient combined cycle turbines are lower relative to smaller combined cycle turbines, it is more likely that larger more efficient combined cycle turbine will operate as base load combustion turbines.

[833] A DOE analysis of a representative NGCC plant using CCS in the ERCOT market indicates that operating at high operating capacity could be profitable today with the IRC 45Q tax credits. *Portfolio Insights: Carbon Capture in the Power Sector.* DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[834] These additional efficiency improvements are noted in the final TSD, *Efficient Generation: Combustion Turbine Electric Generating Units.*

[835] The compliance costs assume the same capacity factors in the base and policy case, that is, without CCS and with CCS. If combined cycle turbine with CCS were to operate at higher capacity factors in the policy case, compliance costs would be reduced.

500 MWe-net plant knowing that it will be de-rated by 11 percent (to a 444 MWe-net plant) with the installation and operation of CCS. In the alternative, the project developer could build a larger 563 MWe-net combined cycle turbine knowing that, with the installation of the carbon capture system, the unit will still be able to provide 500 MWe-net of power to the grid. Although the use of CCS imposes additional energy demands on the affected units, those units are able to accommodate those demands by scaling larger, as needed.

Regardless of whether a unit is scaled larger, the installation and operation of CCS itself does not impact the unit's potential-to-emit any criteria air pollutants. In other words, a new base load stationary combustion turbine EGU constructed using highly efficient generation (the first component of the BSER) would not see an increase in emissions of criteria air pollutants as a direct result of installing and using 90 percent or greater CO_2 capture CCS to meet the second phase standard of performance.[836]

Scaling a unit larger to provide heat and power to the CO_2 capture equipment would have the potential to increase non-GHG air emissions. However, most pollutants would be mitigated or controlled by equipment needed to meet other CAA requirements. In general, the emission rates and flue gas concentrations of most non-GHG pollutants from the combustion of natural gas in stationary combustion turbines are relatively low compared to the combustion of oil or coal in boilers. As such, it is not necessary to use an FGD to pretreat the flue gas prior to CO_2 removal in the CO_2 scrubber column. The sulfur content of natural gas is low relative to oil or coal and resulting SO_2 emissions are therefore also relatively low. Similarly, PM emissions from combustion of natural gas in a combustion turbine are relatively low. Furthermore, the high combustion efficiency of combustion turbines results in relatively low HAP emissions. Additionally, combustion turbines at major sources of HAP are subject to the stationary combustion turbine NESHAP, which includes limits for formaldehyde emissions for new sources that may require installation of an oxidation catalyst (87 FR 13183; March 9, 2022). Regarding NO_X emissions, in most cases, the combustion turbines in new combined cycle units will be equipped with low-NO_X burners to control flame temperature and reduce NO_X formation. Additionally, new combined cycle units are typically subject to major NSR requirements for NO_X emissions, which may require the installation of SCR to comply with a control technology determination by the permitting authority. See section XI.A of this preamble for additional details regarding the NSR program. Although NO_X concentrations may be controlled by SCR, for some amine solvents NO_X in the post-combustion flue gas can react in the CO_2 absorber to form nitrosamines. A conventional multistage water wash or acid wash and a mist eliminator at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.*, nitrosamine) emissions.[837] [838] Acetaldehyde and formaldehyde can form through oxidation of the solvent, however, this can be mitigated by selecting compatible materials to limit catalytic oxidation and interstage cooling in the absorber to limit thermal oxidation.

The use of water for cooling presents an additional issue. Due to their relatively high efficiency, combined cycle EGUs have relatively small cooling requirements compared to other base load EGUs. According to NETL, a combined cycle EGU without CCS requires 190 gallons of cooling water per MWh of electricity. CCS increases the cooling water requirements due both to the decreased efficiency and the cooling requirements for the CCS process to 290 gallons per MWh, an increase of about 50 percent. However, because combined cycle turbines require limited amounts of cooling water, the absolute amount of increase in cooling water required due to use of CCS is relatively small compared to the amount of water used by a coal-fired EGU. A coal-fired EGU without CCS requires 450 gallons or more per MWh and the industry has demonstrated an ability to secure these quantities of water and the EPA has determined that the increased water requirements for CCS can be addressed. In addition, many combined cycle EGUs currently use dry cooling technologies and the use of dry or hybrid cooling technologies for the CO_2 capture process would reduce the need for additional cooling water. Therefore, the EPA is finalizing a determination that the challenges of additional cooling requirements from CCS are limited and do not disqualify CCS from being the BSER.

Stakeholders have shared with the EPA concerns about the safety of CCS projects and that historically disadvantaged and overburdened communities may bear a disproportionate environmental burden associated with CCS projects.[839] The EPA takes these concerns seriously, agrees that any impacts to historically disadvantaged and overburdened communities are important to consider, and has done so as part of its analysis discussed at section XII.E. For the reasons noted above, the EPA does not expect CCS projects to result in uncontrolled or substantial increases in emissions of non-GHG air pollutants from new combustion turbines. Additionally, a robust regulatory framework exists to reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. These projects will likely be subject to major NSR requirements for their emissions of criteria pollutants, and therefore the sources would be required to (1) control their emissions of attainment pollutants by applying BACT and demonstrate the emissions will not cause or contribute to a NAAQS violation, and (2) control their emissions of nonattainment pollutants by applying LAER and fully offset the emissions by securing emission reductions from other sources in the area. Also, as mentioned in section VII.C.1, carbon capture systems that are themselves a major source of HAP should evaluate the applicability of CAA section 112(g) and conduct a case-by-case MACT analysis if required, to establish MACT for any listed HAP, including listed nitrosamines, formaldehyde, and acetaldehyde. But, as also discussed in section VII.C.1, a conventional multistage water or acid wash and mist eliminator (demister) at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.*, nitrosamine) emissions. Additionally, as noted in

[836] While the absolute onsite mass emissions would not increase from the second component of the BSER, the emissions rate on a lb/MWh-net basis would increase by 13 percent.

[837] Sharma, S., Azzi, M., "A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies," *Fuel,* 121, 178 (2014).

[838] Mertens, J., *et al.,* "Understanding ethanolamine (MEA) and ammonia emissions from amine-based post combustion carbon capture: Lessons learned from field tests," *Int'l J. of GHG Control,* 13, 72 (2013).

[839] In outreach with potentially vulnerable communities, residents have voiced two primary concerns. First, there is the concern that their communities have experienced historically disproportionate burdens from the environmental impacts of energy production, and second, that as the sector evolves to use new technologies such as CCS, they may continue to face disproportionate burden. This is discussed further in section XII.E of this preamble.

section VII.C.1.a.i.(C) of this preamble, PHMSA oversight of supercritical CO_2 pipeline safety protects against environmental release during transport and UIC Class VI regulations under the SDWA, in tandem with GHGRP requirements, ensure the protection of USDWs and the security of geologic sequestration.

The EPA is committed to working with its fellow agencies to foster meaningful engagement with communities and protect communities from pollution. This can be facilitated through the existing detailed regulatory framework for CCS projects and further supported through robust and meaningful public engagement early in the technological deployment process.

The EPA also expects that the meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders, including community members who might be adversely impacted by non-GHG pollutants, will have an opportunity to raise this concern with states and permitting authorities. Additionally, state permitting authorities, and project developers are, in general, required to provide public notice and comment on permits for such projects. This provides additional opportunities for affected stakeholders to engage in that process, and it is the EPA's expectation that the responsible entities consider these concerns and take full advantage of existing protections. Moreover, the EPA through its regional offices is committed to thoroughly review permits associated with CO_2 capture.

(E) Impacts on the Energy Sector

The EPA does not believe that determining CCS to be BSER for base load combustion turbines will cause reliability concerns, for several independent reasons. First, the EPA is finalizing a determination that the costs of CCS are reasonable and comparable to other control requirements the EPA has required the electric power industry to adopt without significant effects on reliability. Second, base load combined cycle turbines are only one of many options that companies have to build new generation. The EPA expects there to be considerable interest in building intermediate load and low load combustion turbines to meet demand for dispatchable generation. Indeed, the portion of the combustion turbine fleet that is operating at base load is declining as shown in the EPA's reference case modeling (Power Sector Platform 2023 using IPM reference case, see section IV.F of the preamble). In 2023, combined cycle turbines are only expected to represent 14 percent of all new generating capacity built in the U.S. and only a portion of that is natural gas combined cycle capacity.[840] Several companies have recently announced plans to move away from new combined cycle turbine projects in favor of more non-base load combustion turbines, renewables, and battery storage. For example, Xcel recently announced plans to build new renewable power generation instead of the combined cycle turbine it had initially proposed to replace the retiring Sherco coal-fired plant.[841] Finally, while CCS is adequately demonstrated and cost-reasonable, this final rulemaking allows companies that want to build a base load combined cycle turbine another compliance option to meet its requirements: building a unit that co-fires low-GHG hydrogen in the appropriate amount to meet the standard of performance. In fact, companies are currently pursuing both of these options—units with CCS as well as units that will co-fire low-GHG hydrogen are both in various stages of development. For these reasons, determining CCS to be the BSER for base load units will not cause reliability concerns.

(F) Extent of Reductions in CO_2 Emissions

Designating CCS as a component of the BSER for certain base load combustion turbine EGUs prevents large amounts of CO_2 emissions. For example, a new base load combined cycle EGU without CCS could be expected to emit 45 million tons of CO_2 over its 30-year operating life, or 1.5 million tons of CO_2 per year. Use of CCS would avoid the release of nearly 41 million tons of CO_2 over the operating life of the combined cycle EGU, or 1.37 million tons per year. However, due to the auxiliary/parasitic energy requirements of the carbon capture system, capturing 90 percent of the CO_2 does not result in a corresponding 90 percent reduction in CO_2 emissions. According to the NETL baseline report, adding a 90 percent CO_2 capture system increases the EGU's gross heat rate by 7 percent and the unit's net heat rate by 13 percent. Since more fuel would be consumed in the CCS case, the gross and net emissions rates are reduced by 89.3 percent and 88.7 percent respectively. These amounts of CO_2 emissions and reductions are larger than for any other industrial source, except for coal-fired steam generating units.

(G) Promotion of the Development and Implementation of Technology

The EPA also considered whether determining CCS to be a component of the BSER for new base load combustion turbines will advance the technological development of CCS and concluded that this factor further corroborates our BSER determination. A standard of performance based on highly efficient generation in combination with the use of CCS—combined with the availability of IRC section 45Q tax credits and investments in supporting CCS infrastructure from the IIJA—should result in more widespread adoption of CCS. In addition, while solvent-based CO_2 capture has been adequately demonstrated at the commercial scale, a CCS-based standard of performance may incentivize the development and use of better-performing solvents or other components of the capture equipment.

Furthermore, the experience gained by utilizing CCS with stationary combustion turbine EGUs, with their lower CO_2 flue gas concentration relative to other industrial sources such as coal-fired EGUs, will advance capture technology with other lower CO_2 concentration sources. The EIA 2023 Annual Energy Outlook projects that almost 862 billion kWh of electricity will be generated from natural gas-fired sources in 2040.[842] Much of that generation is projected to come from existing combined cycle EGUs and further development of carbon capture technologies could facilitate increased retrofitting of those EGUs.

(H) Summary of BSER Determination

As discussed, the EPA is finalizing a determination that the second component of the BSER for base load stationary combustion turbines is the utilization of CCS at 90 percent capture. The EPA has determined that 90 percent CCS meets the criteria for BSER for new base load combustion turbines. It is an adequately demonstrated technology that can be implemented a reasonable cost. Importantly, use of CCS at 90 percent capture results in significant reductions of CO_2 as compared to a base load combustion turbine without CCS. In addition, the EPA has considered non-air quality and energy impacts. Considering all these factors together, with particular emphasis on the importance of significantly reducing carbon pollution from these heavily utilized sources, the EPA concludes that

[840] *https://www.eia.gov/todayinenergy/detail.php?id=55419.*

[841] *https://cubminnesota.org/xcel-is-no-longer-pursuing-gas-power-plant-proposes-more-renewable-power/.*

[842] Does not include 114 billion kilowatt hours from natural gas-fired CHP projected in AEO 2023.

CCS at 90 percent capture is BSER for new base load combustion turbines. In addition, selecting CCS at 90 percent capture further promotes the development and implementation of this critical carbon pollution reduction technology, which confirms the appropriateness of determining it to be the BSER.

The BSER for base load combustion turbines contains two components and the EPA is promulgating standards of performance to be implemented in two phases with each phase reflecting the degree of emission reduction achievable through the application of each component of the BSER. The first component of the BSER is most efficient generation—an affected new base load combustion turbine must be constructed (or reconstructed) to meet a phase 1 emission standard that reflects the emission rate of the best performing combustion turbine systems. The phase 1 standard of performance for base load combustion turbines is in effect immediately once the source begins operation. The second component of the BSER, as just discussed, is use of CCS at a 90 percent capture rate. The phase 2 standard of performance for base load combustion turbines reflects the implementation of 90 capture CCS on a highly efficient combined cycle combustion turbine system. The compliance date begins January 1, 2032.

(I) January 2032 Compliance Date

The EPA proposed a compliance date beginning January 1, 2035, for new and reconstructed base load stationary combustion turbines subject to the phase 2 standard of performance based on CCS as the BSER. Some commenters were supportive of the proposed compliance date and some urged the EPA to set an earlier compliance date; the EPA also received comments on the proposed rule that stated that the proposed compliance date was not achievable and referenced longer project timelines for CO_2 capture. The EPA has considered the comments and information available and is finalizing a compliance date of January 1, 2032, for the phase 2 standard of performance for base-load stationary combustion turbines. The EPA is also finalizing a mechanism for a compliance date extension of up to 1 year in cases where a source faces a delay in the installation and startup of controls that are beyond the control of the EGU owner or operator, as detailed in section VIII.N of this preamble.

In total, the January 1, 2032, compliance date allows for more than 7 years for installation of CCS after issuance of this rule for sources that have recently commenced construction. This is consistent with the extended project schedule in the Sargent & Lundy report. This is also greater than the approximately 6 years from start to finish for Boundary Dam Unit 3 and Petra Nova.

As discussed in section VII.C.1.a.i(E), the timing for installation of CCS on existing coal-fired steam generating units is based on the baseline project schedule for the capture plant developed by Sargent and Lundy (S&L)[843] and a review of the available information for installation of CO_2 pipelines and sequestration sites.[844] The representative timeline for CCS for coal-fired steam generating units is detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket, and the anticipated timeline for development of a CCS project for application at a new or reconstructed base load stationary combustion turbine would be similar. The explanations the EPA provided in section VII.C.1.a.i(E) regarding the timeline for long-term coal-fired steam generating units generally apply to new combustion turbines as well. The EPA expects that the owners or operators of affected combustion turbines will be able to complete the design, planning, permitting, engineering, and construction steps for the carbon capture and transport and storage systems in a similar amount of time as projects for coal-fired EGUs.

While those considerations apply in general, the EPA notes that the timeline for the installation of CCS on coal-fired steam generating units accounted for the state plan development process. Because there are not state plans required for new combustion turbines, new sources can commit to beginning substantial work earlier (*e.g.,* FEED studies, right-of-way acquisition), immediately after the completion of feasibility work. However, the EPA also recognizes that other elements of a state plan (*e.g.,* RULOF), by which a source under specific circumstances could have a later compliance date, are not available to new sources. Therefore, while the timeline for CCS on coal-fired steam generating units is based on the baseline S&L capture plant schedule (about 6.25 years), the EPA bases the timeline for CCS on new combustion turbines on the extended S&L capture plant schedule (7 years).

As discussed, base load stationary combustion turbines that commence construction or reconstruction on or after May 23, 2023, are subject to standards of performance that are implemented initially in two phases. New stationary combustion turbines that are designed and constructed for the purpose of operating in the base load subcategory (*i.e.,* at a 12-operating month capacity factor of greater than 40 percent) that hypothetically commenced construction on May 23, 2023, could, according to the schedule allowing, conservatively, up to 7 years to develop a CCS project, have a system constructed and on-line by May 23, 2030. However, the EPA is finalizing a compliance date of January 1, 2032, because some base load combined cycle stationary combustion projects that commenced construction between May 23, 2023, and the date of this final rule, may not have included CCS in the original design and planning for the new EGU and, therefore, would be unlikely to be able to have an operational CCS system available by May 23, 2030.

Further, the EPA notes that a delayed compliance date (of January 1, 2035) was proposed for the phase 2 standards of performance due to overlapping demands on the capacity to design, construct, and operate carbon capture systems as well as pipeline systems that would potentially be needed to support CCS projects for existing steam generating units and other industrial sources. As discussed in section VII.C.1.a.i(E), in this action the EPA is finalizing a compliance date of January 1, 2032 for long term coal-fired steam generating EGUs to meet a standard of performance based on 90 percent capture CCS. This compliance date for long-term coal-fired steam generating EGUs places fewer demands on the capacity to design, construct, and operate carbon capture systems and the associated infrastructure for those sources. Therefore, the EPA does not believe that there is a need to extend the compliance date for phase 2 standards for base load combustion turbine EGUs by 5 years beyond that for existing coal-fired steam generating EGUs, as proposed.

Considering these factors, the EPA is therefore finalizing the compliance date of January 1, 2032 for base load combustion turbine EGUs to meet the phase 2 standard of performance. This is the same compliance date applicable to existing long term coal-fired steam generating EGUs that are subject to a standard of performance based on 90 percent capture CCS. The EPA assumes the timelines for development of the various components of CCS for an existing coal-fired steam generating

[843] CO_2 Capture Project Schedule and Operations Memo, Sargent & Lundy (2024).

[844] Transport and Storage Timeline Summary, ICF (2024).

EGU, as discussed in section VII.C.1.a.i(E), are very similar for those components for a CCS system serving a new or reconstructed base load combustion turbine EGU.

Some commenters argued that because the power sector will require some amount of time before CCS and associated infrastructure may be installed on a widespread basis, CCS cannot be considered adequately demonstrated. This argument is similar to the argument, discussed in section V.C.2.b, that in order to be adequately demonstrated, a technology must be in widespread commercial use. Both arguments are incorrect. Under CAA section 111, for a control technology to qualify as the BSER, the EPA must demonstrate that it is adequately demonstrated for affected sources. The EPA must also show that the industry can deploy the technology at scale in the compliance timeframe. That the EPA has provided lead time in order to ensure adequate time for industry to deploy the technology at scale shows that the EPA is meeting its statutory obligation, not the inverse. Indeed, it is not at all unusual for the EPA to provide lead time for industry to deploy new technology. The EPA's approach is in line with the statutory text and caselaw encouraging technology-forcing standard-setting cabined by the EPA's obligation to ensure that its standards are reasonable and achievable.

CCS is clearly adequately demonstrated, and ripe for wider implementation. Nevertheless, the EPA acknowledged in the proposed rule, and reaffirms now, that the power sector will require some amount of lead time before individual plants can install CCS as necessary. Deploying CCS requires the building of capture facilities, pipelines to transport captured CO_2 to sequestration sites, and the development of sequestration sites. This is true for both existing coal-fired steam generating EGUs, some of which would be required to retrofit with CCS under the emission guidelines included in this final rulemaking, and new gas-fired combustion turbine EGUs, which must incorporate CCS into their construction planning.

In this final rulemaking, the EPA is setting a compliance deadline of January 1, 2032 for the CCS-based standard for new base load combustion turbines. The EPA determined, examining the evidence and exercising its appropriate discretion to do so, that this is a reasonable amount of time to allow for CCS buildout at the plant level. As the EPA explained at proposal, D.C. Circuit caselaw supports this approach. There, the EPA cited *Portland Cement* v. *Ruckelshaus*, for the proposition that "D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the 'adequately demonstrated' criterion—even if the controls require some amount of 'lead time,' which the court has defined as 'the time in which the technology will have to be available.' " (footnote omitted). Nothing in the comments alters the EPA's view of the relevant legal requirements related to adequate demonstration or lead time.

d. BSER for Base Load Subcategory—Third Component

The EPA proposed a third component of the BSER of 96 percent (by volume) hydrogen co-firing in 2038 for owners/operators of base load combustion turbines that elected to comply with the low-GHG hydrogen co-firing pathway. As discussed in the next section, the EPA is not finalizing the proposed BSER pathway of low-GHG hydrogen co-firing at this time. Therefore, the Agency is not finalizing a third component of the BSER for base load combustion turbines.

5. Technologies Proposed by the EPA But Ultimately Not Determined To Be the BSER

The EPA is not finalizing its proposed BSER pathway of low-GHG hydrogen co-firing for new and reconstructed base load and intermediate load combustion turbines as part of this action. In light of public comments and additional analysis, uncertainties regarding projected costs prevent the EPA from determining that low-GHG hydrogen is a component of the BSER at this time.

The next section provides a summary of the proposed requirements for low-GHG hydrogen followed by, in section VIII.F.5.b, an explanation for why the Agency is not finalizing its proposed determination that low-GHG hydrogen co-firing is BSER. In section VIII.F.6, the EPA discusses considerations for the potential use of hydrogen. In section VIII.F.6.a, the Agency explains why it is not limiting the hydrogen that may be co-fired in a new or reconstructed combustion turbine to only low-GHG hydrogen. In section VIII.F.6.b, the Agency discusses its decision to not include a definition of low-GHG hydrogen.

a. Proposed Low-GHG Hydrogen Co-Firing BSER

The EPA proposed that new and reconstructed intermediate load combustion turbines were subject to a second component of the BSER that consisted of co-firing 30 percent (by volume) low-GHG hydrogen by 2032. The EPA also proposed that new and reconstructed base load combustion turbines could elect either (i) a second component of BSER that consisted of installing CCS by 2035, or (ii) a second and third component of BSER that consisted of co-firing 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent (by volume) low-GHG hydrogen by 2038.

The EPA solicited comment on whether the Agency should finalize both the CCS and low-GHG hydrogen co-firing pathways as separate subcategories with separate standards of performance and on whether the EPA should finalize one pathway with the option of meeting the standard of performance using either system of emission reduction (88 FR 33277, May 23, 2023). The EPA also solicited comment on the option of finalizing a single standard of performance based on the application of CCS for the base load subcategory (88 FR 33283, May 23, 2023).

b. Explanation for Not Finalizing Low-GHG Hydrogen Co-Firing as a BSER

The EPA is not finalizing a low-GHG hydrogen co-firing component of the BSER at this time. The EPA proposed that co-firing low-GHG hydrogen qualified as a BSER pathway because the components of the system met specific criteria, namely that the capability of combustion turbines to co-fire hydrogen was adequately demonstrated and there was a reasonable expectation that the necessary quantities of low-GHG hydrogen would be nationally available by 2032 and 2038 at reasonable cost. Due to concerns raised by commenters, the EPA conducted additional analysis of key components of the low-GHG hydrogen best system and the Agency's proposed determination that low-GHG hydrogen co-firing qualified as the BSER. This additional analysis, discussed further below, indicated that the currently estimated cost of low-GHG hydrogen in 2030 is higher than anticipated at proposal. These higher cost estimates were key factors in the EPA's decision to revise its 2030 cost estimate for delivered low-GHG hydrogen.

While the EPA is not finalizing a BSER determination with regard to co-firing with low-GHG hydrogen as part of this rulemaking and is therefore not making any determination about whether such a practice is adequately demonstrated, the Agency notes that there are multiple models of combustion turbines available from major manufacturers that have successfully demonstrated the ability to combust hydrogen. Manufacturers have stated that they expect to have additional models of combustion turbines available that will be capable of firing 100 percent hydrogen while limiting emissions of other pollutants (*e.g.*, NO_X). The EPA further discusses considerations around the technical feasibility of hydrogen co-firing in new and reconstructed combustion turbines, and what they mean for the potential use of hydrogen co-firing as a compliance strategy, in section VIII.F.6 of this preamble.

While the EPA believes that hydrogen co-firing is technically feasible based on combustion turbine technology, information about how the low-GHG hydrogen production industry will develop in the future is not sufficiently certain for the EPA to be able to determine that adequate quantities will be available. That is, there remain, at the time of this final rulemaking, uncertainties pertaining to how the future nationwide availability of low-GHG hydrogen will develop. Relatedly, estimates of its future costs are more uncertain than anticipated at proposal. For low-GHG hydrogen to meet the BSER criteria as proposed, the EPA would have to be able to determine that significant quantities of low-GHG hydrogen will be available at reasonable costs such that affected sources in the power sector nationwide could rely on it for use by 2032 and 2038. While some analyses [845] show that this will likely be the case, the full set of information necessary to support such a determination is not available at this time. However, the EPA believes this may change as the low-GHG hydrogen industry continues to develop. The Agency plans to monitor the development of the industry; if appropriate, the EPA will reevaluate its findings and establish standards of performance that achieve additional emission reductions. Furthermore, as noted above, the EPA considers the co-firing of hydrogen to be technically feasible in multiple models of available combustion turbines.

As noted above, the EPA has revised its cost analysis of low-GHG hydrogen and determined that, due to the present uncertainty, estimated future hydrogen costs are higher than at proposal. The higher estimated cost of low-GHG hydrogen relative to proposal is the key factor in the EPA's decision to not finalize low-GHG hydrogen co-firing as a BSER pathway for new and reconstructed base load and intermediate load combustion turbines at this time.

In the proposal, the EPA modeled low-GHG hydrogen as a fuel available at a fixed delivered [846] price of $1/kg (or $7.40/MMBtu) in the baseline. This cost decreased to $0.50/kg (or $3.70/MMBtu) in the Integrated Proposal case when the second phase of the new combustion turbine standard began in 2032. This fuel was assumed to be ''clean'' and eligible for the highest subsidy under the IRC section 45V hydrogen production tax credit and would comply with the proposed requirement to use low-GHG hydrogen (88 FR 33314, May 23, 2023). The EPA's revised modeling of the power sector for the final rule used a price of $1.15/kg for delivered low-GHG hydrogen in both the final baseline and policy cases. For additional discussion of the EPA's revised modeling of the power sector and increased cost estimate for low-GHG hydrogen, see the final RIA included in the docket for this rulemaking.

The U.S. Department of Energy's 2022 report, *Pathways to Commercial Liftoff: Clean Hydrogen*, informed the EPA's revised low-GHG hydrogen cost analysis. According to the DOE report, the cost to produce, transport, store, and deliver low-GHG or ''clean'' hydrogen is expected to be between $0.70/kg and $1.15/kg by 2030 with the IRA's $3/kg maximum IRC section 45V production tax credit included.[847] The report also points out that the power sector is competing with other industrial sectors—such as transportation, ammonia and chemical production, oil refining, and steel manufacturing—in terms of potential downstream applications of clean hydrogen for the purpose of reducing GHG emissions. The DOE report also estimates that $0.40/kg to $0.50/kg is the price the power sector would be willing to pay for clean hydrogen.

Some analyses of future hydrogen costs provide estimates that are higher than those of the DOE. For example, public commenters estimated the cost of delivered ''clean'' hydrogen to be less than $3/kg by 2030 before declining to $2/kg by 2035. These estimates of delivered hydrogen costs include the IRC section 45V hydrogen production tax credits contained in the IRA, but they do not reflect regulations proposed by the U.S. Department of the Treasury pertaining to clean hydrogen production tax and energy credits, which proposed certain eligibility parameters (88 FR 89220, December 26, 2023). Until Treasury's regulations on the IRC section 45V hydrogen production tax credit are final, some analysts only estimate future production costs of hydrogen, not delivered costs, and do not include any projected potential impacts of the IRA incentives. For example, both McKinsey and BloombergNEF project the unsubsidized production cost of clean hydrogen to be approximately $2/kg by 2030, which could lead to negative to zero prices for some subsidized hydrogen after considering transportation and storage.[848] [849] One of the highest estimates for the unsubsidized production cost of clean hydrogen is from the Rhodium Group, which estimates the price to be from $3.39/kg to $4.92/kg in 2030.[850] Again, it should be noted these estimates do not include additional costs for transportation and storage. The increased cost projections for low-GHG hydrogen production are partly due to higher costs for capital equipment, such as electrolyzers. The DOE published a Program Record [851] detailing higher costs than previously estimated by levering data from the regional clean hydrogen hubs and other literature. Costs increases are predominantly driven by inflation, supply chain cost increases, and higher estimated installation costs. However, there is a significant range in electrolyzer costs; some companies cite costs that are significantly lower ($750-$900/kW installed cost) [852] than that published in the Program Record.

[845] Electric Power Research Institute (EPRI). (November 3, 2023). Impact of IRA's 45V Clean Hydrogen Production Tax Credit. White paper. *https://www.epri.com/research/products/000000003002028407*.

[846] The delivered price includes the cost to produce, transport, and store hydrogen.

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

[848] Heid, B.; Sator, A.; Waardenburg, M.; and Wilthaner, M. (25 Oct 2022). Five charts on hydrogen's role in a net-zero future. McKinsey & Company. *https://www.mckinsey.com/capabilities/sustainability/our-insights/five-charts-on-hydrogens-role-in-a-net-zero-future*.

[849] Schelling, K. (9 Aug 2023). Green Hydrogen to Undercut Gray Sibling by End of Decade. BloombergNEF. *https://about.bnef.com/blog/green-hydrogen-to-undercut-gray-sibling-by-end-of-decade/*.

[850] Larsen, J.; King, B.; Kolus, H.; Dasari, N.; Bower, G.; and Jones, W. (12 Aug 2022). A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act. Rhodium Group. *https://rhg.com/research/climate-clean-energy-inflation-reduction-act/*.

[851] U.S. Department of Energy (DOE). (February 22, 2024). *Summary of Electrolyzer Cost Data Synthesized from Applications to the DOE Clean Hydrogen Hubs Program*. DOE Hydrogen Program, Office of Clean Energy Demonstrations Program Record. *https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/24002-summary-electrolyzer-cost-data.pdf*.

[852] Martin, P. (December 18, 2023). What gives Bill Gates-backed start-up Electric Hydrogen the edge over other electrolyzer makers? Hydrogen

6. Considerations for the Potential Use of Hydrogen

The ability of combustion turbines to co-fire hydrogen can effectively reduce stack GHG emissions. Hydrogen also offers unique solutions for decarbonization because of its potential to provide dispatchable, clean energy with long-term storage and seasonal capabilities. For example, hydrogen is an energy carrier that can provide long-term storage of low-GHG energy that can be co-fired in combustion turbines and used to balance load with the increasing volumes of variable generation. These services support the reliability of the power system while facilitating the integration of variable zero-emitting energy resources and supporting decarbonization of the electric grid. One technology with the potential to reduce curtailment is energy storage, and some power producers envision a role for hydrogen to supplement natural gas as a fuel to support the balancing and reliability of an increasingly decarbonized electric grid.

Hydrogen is a zero-GHG emitting fuel when combusted, so that co-firing it in a combustion turbine in place of natural gas reduces GHG emissions at the stack. For this reason, certain owners/operators of combustion turbines in the power sector may elect to co-fire hydrogen in the coming years to reduce onsite GHG emissions.[853] Co-firing low-emitting fuels—sometimes referred to as clean fuels—is a traditional type of emissions control. However, the EPA recognizes that even though the *combustion* of hydrogen is zero-GHG emitting, its *production* can entail a range of GHG emissions, from low to high, depending on the method. These differences in GHG emissions from the different methods of hydrogen production are well-recognized in the energy sector (88 FR 33306, May 23, 2023), and, in fact, hydrogen is generally characterized by its production method and the attendant level of GHG emissions.

While the focus of this rule is the reduction of stack GHG emissions from combustion turbines, the EPA also recognizes that, to ensure overall GHG benefits, it is important any hydrogen used in the power sector be low-GHG hydrogen. Thus, even though the EPA is not finalizing the use of low-GHG hydrogen as a component of the BSER for base load or intermediate load combustion turbines, it maintains that the type of hydrogen used (*i.e.*, the method by which the hydrogen was produced) should be a primary consideration for any source that decides to co-fire hydrogen. Again, the Agency reiterates its concern that sources in the power sector that choose to co-fire hydrogen to reduce their GHG emission rate should co-fire only low-GHG hydrogen to achieve overall GHG reductions and important climate benefits.

In the proposal, the EPA solicited comment on whether it is necessary to require low-GHG hydrogen. Similarly, the EPA also solicited comment as to whether the low-GHG hydrogen requirement could be treated as severable from the remainder of the standard such that the standard could function without this requirement. The EPA also solicited comment on a host of recordkeeping and reporting topics. These pertained to the complexities of tracking the sources of quantities of produced low-GHG hydrogen and the public interest in such data.

a. Explanation for Not Requiring Hydrogen Used for Compliance To Be Low-GHG Hydrogen

The EPA proposed that the type of hydrogen co-fired must be limited to low-GHG hydrogen, and not include other types of hydrogen.[854] This requirement was proposed to prevent the anomalous outcome of a GHG control strategy contributing to an increase in overall GHG emissions; the provision that only low-GHG hydrogen could be used for compliance mirrored the EPA's proposal that low-GHG hydrogen, in particular, could qualify as a component of the BSER. For the reasons explained below, the EPA is not finalizing a requirement that any hydrogen that sources choose to co-fire must be low-GHG hydrogen. However, the Agency continues to stress, notwithstanding the lack of requirement under this rule, the importance of ensuring that any hydrogen used in combustion turbines is low-GHG hydrogen. The EPA's choice to not finalize a low-GHG requirement at this time is based in large part on knowledge of current and future efforts that will reinforce the availability and role of low-GHG hydrogen in the national economy and, more specifically, in the power sector. As discussed further below, this decision is against the backdrop of ongoing developments in the public and private sectors, Treasury's regulations implementing a tax credit for the production of clean hydrogen, multiple Federal government grant and assistance programs, and the EPA's investigation into methods to control emissions of air pollutants from hydrogen production.

The EPA's decision to not require that any hydrogen used for compliance be low-GHG hydrogen was based primarily on the current market and policy developments regarding hydrogen production at this particular point in time, including the clean hydrogen production tax credits. There are currently multiple private and public efforts to develop, *inter alia,* greenhouse gas accounting practices, verification protocols, reporting conventions, and other elements that will help determine how low-GHG hydrogen is measured, tracked, and verified over the next several years. For example, Treasury is expected to finalize parameters for evaluating overall emissions associated with hydrogen production pathways as it prepares to implement IRC section 45V.[855] The overall objective of Treasury's parameters is to recognize that different methods of hydrogen production generate different amounts of GHG emissions while encouraging lower-emitting production methods through the multi-tier hydrogen production tax credit (IRC section 45V) (see 88 FR 89220, December 26, 2023). In light of these nascent but fast-moving efforts, the EPA does not believe it is reasonable or helpful to prescribe its own definitions, protocols, and requirements for low-GHG hydrogen at this point in time.

Furthermore, the Agency anticipates that combustion turbines will, despite not being required to do so, use low-GHG hydrogen (to the extent they are co-firing hydrogen as a compliance strategy). Depending on market development in the coming decade, it is reasonable to expect that any hydrogen used in the power sector would generally be low-GHG hydrogen, even without a specific BSER pathway or low-GHG-only requirement included in this final NSPS. For example, several utilities with dedicated access to affordable low-GHG hydrogen are actively developing co-firing projects with the goal of reducing their GHG

Insight. *https://www.hydrogeninsight.com/electrolysers/what-gives-bill-gates-backed-start-up-electric-hydrogen-the-edge-over-other-electrolyser-makers-/2-1-1572694.*

[853] In June 2022, the U.S. Department of Energy (DOE) Loans Program Office issued a $504.4 million loan guarantee to finance the Advanced Clean Energy Storage (ACES) project in Delta, Utah. ACES expects to utilize a 220 MW bank of electrolyzers and curtailed renewable energy to produce clean hydrogen that will be stored in salt caverns. The hydrogen will fuel an 840 MW combined cycle combustion turbine at the Intermountain Power Project facility. *https://www.energy.gov/lpo/advanced-clean-energy-storage.*

[854] 88 FR 33240, 33315 (May 23, 2023).

[855] U.S. Department of the Treasury. (October 5, 2022). Treasury Seeks Public Input on Implementing the Inflation Reduction Act's Clean Energy Tax Incentives. Press release. *https://home.treasury.gov/news/press-releases/jy0993.*

emissions. The infrastructure funding and tax incentives included in the IIJA and the IRA are also driving the development of the low-GHG hydrogen supply chain. These rapid changes in the hydrogen marketplace not only counsel against the EPA's locking in its own requirements at this time; they also provide confidence that greater quantities of low-GHG hydrogen will be available moving forward, even if the precise timing and quantity cannot currently be accurately forecast. The EPA also provides information further below about its intentions to open a non-regulatory docket to engage stakeholders on potential future rulemakings for thermochemical-based hydrogen production facilities to address issues pertaining to GHG, criteria, and HAP emissions.

i. Hydrogen Production and Associated GHGs

Hydrogen is used in industrial processes; in recent years, applications of hydrogen co-firing have also expanded to include stationary combustion turbines used to generate electricity. Several commenters responded to the proposal by stating that to fully evaluate the potential GHG emission reductions from co-firing low-GHG hydrogen in a combustion turbine EGU, it is important to consider the different processes for producing hydrogen and the GHG emissions associated with each process. The EPA agrees that the method of hydrogen production is critical to consider when assessing whether hydrogen co-firing actually reduces overall GHG emissions. As stated previously, the varying levels of CO_2 emissions associated with different hydrogen production processes are well-recognized, and stakeholders routinely refer to hydrogen on the basis of the different production processes and their different GHG profiles.

ii. Technological and Market Transformation of Low-GHG Hydrogen Resources

In the proposal, the EPA highlighted ongoing efforts—independent of any BSER pathway, requirement, or performance standard—of combustion turbine manufacturers and industry stakeholders to research, develop, and deploy hydrogen co-firing technologies (88 FR 33307, May 23, 2023). Their co-firing demonstrations are producing results, such as increasing the percentages (by volume) of hydrogen that a turbine can combust while answering questions regarding safety, performance, reliability, durability, and the emission of other pollutants (*e.g.*, NO_X). Such efforts by industry to invest in the development of hydrogen co-firing, and specifically in projects designed to co-fire low-GHG hydrogen, in particular, give the EPA confidence that any hydrogen that sources do choose to co-fire for compliance under this rule will be low-GHG hydrogen. As these efforts progress, a sharper understanding of costs will come into focus while significant Federal funding—through grants, financial assistance programs, and tax incentives included in the IIJA and the IRA discussed below—is intended to support the continued development of a nationwide clean hydrogen supply chain.

For the most part, companies that have announced that they are exploring the use of hydrogen co-firing have stated that they intend to use low-GHG hydrogen in the future as greater quantities of the fuel become available at lower, stabilized prices. Many utilities and merchant generators own and are developing low-GHG electricity generating sources as well as combustion turbines, with the intent to produce low-GHG hydrogen for sale and to use a portion of it to fuel their stationary combustion turbines.[856] [857] This emerging trend lends support to the view that, while acknowledging the uncertainty of the ultimate timing of implementation, there is growing interest in hydrogen co-firing in the power sector and stakeholders are developing these resources with the intent to increase access to low-GHG hydrogen as they increase hydrogen utilization in their co-firing applications. Additional information provided by commenters and analysis by the EPA identified several new combustion turbine projects planning to co-fire low-GHG hydrogen, even though these low-GHG methods of hydrogen production are not currently readily available on a nationwide basis.[858] [859] [860]

iii. Infrastructure Funding and Tax Incentives Included in the IIJA and IRA

In both the 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 over the coming decades. For example, the IIJA included the H2Hubs program, the Clean Hydrogen Manufacturing and Recycling Program, the Clean Hydrogen Electrolysis Program, and a non-regulatory Clean Hydrogen Production Standard (CHPS).[861] In the IRA, Congress enacted or expanded tax credits to encourage the production and use of low-GHG hydrogen.[862] In addition, as discussed in the proposal, IRA section 60107 added new CAA section 135, or the Low Emission Electricity Program (LEEP). This provision provides $1 million for the EPA to assess the GHG emissions reductions from changes in domestic electricity generation and use anticipated to occur annually through fiscal year 2031; and further provides $18 million for the EPA to promulgate additional CAA rules to ensure GHG emissions reductions that go beyond the reductions expected in that assessment. CAA section 135(a)(5)–(6).

Given the incentives provided in both the IRA and IIJA for low-GHG hydrogen production and the current trajectory of hydrogen use in the power sector, by 2032, the start date for compliance with the proposed second phase of the NSPS, low-GHG hydrogen may be more widely available and possibly the most common source of hydrogen available for electricity production. It is also possible that the cost of delivered low-GHG hydrogen will continue to decline toward the DOE's Hydrogen Shot target. These expectations are based on a combination of economies of scale as low-GHG production methods expand, the increasing availability of low-cost input electricity—largely powered by zero- or low-emitting energy sources—

[856] Mitsubishi Power. (2020). *Intermountain Power Agency Orders MHPS JAC Gas Turbine Technology for Renewable-Hydrogen Energy Hub. https://power.mhi.com/regions/amer/news/200310.html*.

[857] Intermountain Power Agency (2022). *https://www.ipautah.com/ipp-renewed/*.

[858] Los Angeles Department of Water & Power (2023). *Initial Study: Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project. https://ceqanet.opr.ca.gov/2023050366*.

[859] *https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf*.

[860] Hering, G. (2021). First major US hydrogen-burning power plant nears completion in Ohio. *S&P Global Market Intelligence. https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081221-first-major-us-hydrogen-burning-power-plant-nears-completion-in-ohio*.

[861] U.S. Department of Energy (DOE). (September 22, 2022). Clean Hydrogen Production Standard. Hydrogen and Fuel Cell Technologies Office. *https://www.energy.gov/eere/fuelcells/articles/clean-hydrogen-production-standard*.

[862] These tax credits include IRC section 45V (tax credit for production of hydrogen through low- or zero-emitting processes), IRC section 48 (tax credit for investment in energy storage property, including hydrogen production), IRC section 45Q (tax credit for CO_2 sequestration from industrial processes, including hydrogen production); and the use of hydrogen in transportation applications, IRC section 45Z (clean fuel production tax credit), IRC section 40B (sustainable aviation fuel credit).

and learning by doing as more combustion turbine projects are developed. The EPA recognizes that the pace and scale of government programs and private research suggest that the Agency will gain significant experience and knowledge on this topic in the future.

iv. EPA Non-Regulatory Docket and Stakeholder Engagement on Potential Regulatory Approaches for Emissions From Thermochemical Hydrogen Production

In addition to the ongoing industry development of and Congressional support for low-GHG hydrogen, the EPA is also taking steps consistent with the importance of mitigating GHG emissions associated with hydrogen production. On September 15, 2023, the EPA received a petition from the Environmental Defense Fund (EDF) along with 13 other health, environmental, and community groups, to regulate fossil and other thermochemical methods of hydrogen production given the current emissions from these facilities and the anticipated growth in the sector spurred by IRA incentives. The petition notes that facilities producing hydrogen for sale produced about 10 MMT of hydrogen and emitted more than 40 MMT of CO_2e in 2020.[863] Regulatory safeguards are advocated by petitioners to help ensure that the anticipated growth in this sector does not result in an unbounded increase in emissions of GHGs, criteria, and hazardous air pollutants (HAP). The petition requests that the EPA list hydrogen production facilities as significant sources of pollution under CAA sections 111 and 112, and that the EPA develop both standards of performance for new and modified hydrogen production facilities as well as emission guidelines for existing facilities. The development of emission standards for HAP, including but not limited to methanol, was also requested by petitioners. Petitioners assert that emissions of CO_2, NO_X, and PM should be addressed under the EPA's section 111 authorities, and HAP should be addressed by EPA regulations under section 112.[864] The EPA is reviewing the petition. As a predicate to potential future rulemakings, the Agency is developing a set of framing questions and opening a non-regulatory docket to solicit public comment on potential approaches for regulation of GHGs and criteria pollutants under CAA section 111 and an exploration of the appropriateness of regulating HAP emissions under CAA section 112 and on potential section 114 reporting requirements to address this growing industry.

b. Definition of Low-GHG Hydrogen

The EPA proposed to define low-GHG hydrogen as hydrogen produced with emissions of less than 0.45 kg CO_2e/kg H_2, from well-to-gate, which aligned with the highest of the four tiers of tax credits available for hydrogen production, IRC section 45V(b)(2)(D). At that GHG emission rate or less, hydrogen producers are eligible for a tax credit of $3/kg. With these provisions, Congress indicated its judgement as to what GHG levels could be attained by the lowest-GHG hydrogen production, and its intention to incentivize production of that type of hydrogen. Congress's views informed the EPA's proposal to define low-GHG hydrogen for purposes of making the BSER for this CAA section 111 rulemaking consistent with IRC section 45V(b)(2)(D).

The EPA solicited comment broadly on its proposed definition for low-GHG hydrogen, and on alternative approaches, to help develop reporting and recordkeeping requirements that would have ensured that co-firing low-GHG hydrogen minimized GHG emissions, and that combustion turbines subject to this standard utilized only low-GHG hydrogen. The EPA also solicited comment on whether it was necessary to provide a definition of low-GHG hydrogen in this final rule.

The EPA is not finalizing a definition of low-GHG hydrogen in this action. Because the Agency is not finalizing co-firing with low-GHG hydrogen as a component of the BSER for certain combustion turbines and is not finalizing a requirement that any hydrogen co-fired for compliance by low-GHG hydrogen, there is no reason to finalize a definition of low-GHG hydrogen at this time.

7. Other Options for BSER

The EPA considered several other systems of emission reduction as candidates for the BSER for combustion turbines but is not determining them to be the BSER. They include partial capture CCS, CHP and the hybrid power plant, as discussed below.

a. Partial Capture CCS

Partial capture for CCS was not determined to be BSER because the emission reductions are lower and the costs would, in general, be higher. As discussed in section IV, individual natural gas-fired combined cycle combustion turbines are the second highest-emitting individual plants in the nation, and the natural gas-fired power plant sector is higher-emitting than all other sectors. CCS at 90 percent capture removes very high absolute amounts of emissions. Partial capture CCS would fail to capture large quantities of emissions. With respect to costs, designs for 90 percent capture in general take greater advantage of economy of scale. Eligibility for the IRC section 45Q tax credit for existing EGUs requires design capture rates equivalent to 75 percent of a baseline emission rate by mass. Sources with partial capture rates that do not meet that requirement would not be eligible for the tax credit and as a result, for them, the CCS requirement would be too expensive to qualify for as the BSER. Even assuming partial capture rates meet that definition, lower capture rates would receive fewer returns from the IRC section 45Q tax credit (since these are tied to the amount of carbon sequestered, and all else equal lower capture rates would result in lower amounts of sequestered carbon) and costs would thereby be higher.

b. Combined Heat and Power (CHP)

CHP, also known as cogeneration, is the simultaneous production of electricity and/or mechanical energy and useful thermal output from a single fuel. CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP has lower-emission rates and can be more economic than separate electric and thermal generation. However, a critical requirement for a CHP facility is that it primarily generates thermal output and generates electricity as a byproduct and must therefore be physically close to a thermal host that can consistently accept the useful thermal output. It can be particularly difficult to locate a thermal host with sufficiently large thermal demands such that the useful thermal output would impact the emissions rate. The refining, chemical manufacturing, pulp and paper, food processing, and district energy systems tend to have large thermal demands. However, the thermal demand at these facilities is generally only sufficient to support a smaller EGU, approximately a maximum of several hundred MW. This

[863] Petition for Rulemaking to List and Establish National Emission Standards for Hydrogen Production Facilities under the Clean Air Act Sections 111 and 112. The petition can be accessed at *https://www.edf.org/sites/default/files/2023-09/Petition%20for%20Rulemaking%20-%20Hydrogen%20Production%20Facilities%20-%20CAA%20111%20and%20112%20-%20EDF%20et%20al.pdf.*

[864] *Id.*

would limit the geographically available locations where new generation could be constructed in addition to limiting its size. Furthermore, even if a sufficiently large thermal host were in close proximity, the owner/operator of the EGU would be required to rely on the continued operation of the thermal host for the life of the EGU. If the thermal host were to shut down, the EGU could be unable to comply with the standard of performance. This reality would likely result in difficulty in securing funding for the construction of the EGU and could also lead the thermal host to demand discount pricing for the delivered useful thermal output. For these reasons, the EPA did not propose CHP as the BSER.

c. Hybrid Power Plant

Hybrid power plants combine two or more forms of energy input into a single facility with an integrated mix of complementary generation methods. While there are multiple types of hybrid power plants, the most relevant type for this proposal is the integration of solar energy (*e.g.,* concentrating solar thermal) with a fossil fuel-fired EGU. Both coal-fired and combined cycle turbine EGUs have operated using the integration of concentrating solar thermal energy for use in boiler feed water heating, preheating makeup water, and/or producing steam for use in the steam turbine or to power the boiler feed pumps.

One of the benefits of integrating solar thermal with a fossil fuel-fired EGU is the lower capital and operation and maintenance (O&M) costs of the solar thermal technology. This is due to the ability to use equipment (*e.g.,* HRSG, steam turbine, condenser, *etc.*) already included at the fossil fuel-fired EGU. Another advantage is the improved electrical generation efficiency of the non-emitting generation. For example, solar thermal often produces steam at relatively low temperatures and pressures, and the conversion of the thermal energy in the steam to electricity is relatively low efficiency. In a hybrid power plant, the lower quality steam is heated to higher temperatures and pressures in the boiler (or HRSG) prior to expansion in the steam turbine, where it produces electricity. Upgrading the relatively low-grade steam produced by the solar thermal facility in the boiler improves the relative conversion efficiencies of the solar thermal to electricity process. The primary incremental costs of the non-emitting generation in a hybrid power plant are the costs of the mirrors, additional piping, and a steam turbine that is 10 to 20 percent larger than that in a comparable fossil-only EGU to accommodate the additional steam load during sunny hours. A drawback of integrating solar thermal is that the larger steam turbine will operate at part loads and reduced efficiency when no steam is provided from the solar thermal panels (*i.e.,* the night and cloudy weather). This limits the amount of solar thermal that can be integrated into the steam cycle at a fossil fuel-fired EGU.

In the 2018 Annual Energy Outlook,[865] the levelized cost of concentrated solar power (CSP) without transmission costs or tax credits is $161/MWh. Integrating solar thermal into a fossil fuel-fired EGU reduces the capital cost and O&M expenses of the CSP portion by 25 and 67 percent compared to a stand-alone CSP EGU respectively.[866] This results in an effective LCOE for the integrated CSP of $104/MWh. Assuming the integrated CSP is sized to provide 10 percent of the maximum steam turbine output and the relative capacity factors of a combined cycle turbine and the CSP (those capacity factors are 65 and 25 percent, respectively) the overall annual generation due to the concentrating solar thermal would be 3 percent of the hybrid EGU output. This would result in a 3 percent reduction in the overall CO_2 emissions and a 1 percent increase in the LCOE, without accounting for any reduction in the steam turbine efficiency. However, these costs do not account for potential reductions in the steam turbine efficiency due to being oversized relative to a non-hybrid EGU. A 2011 technical report by the National Renewable Energy Laboratory (NREL) cited analyses indicating that solar augmentation of fossil power stations is not cost-effective, although likely less expensive and containing less project risk than a stand-alone solar thermal plant. Similarly, while commenters stated that solar augmentation has been successfully integrated at coal-fired plants to improve overall unit efficiency, commenters did not provide any new information on costs or indicate that such augmentation is cost-effective.

In addition, solar thermal facilities require locations with abundant sunshine and significant land area in order to collect the thermal energy. Existing concentrated solar power projects in the U.S. are primarily located in California, Arizona, and Nevada with smaller projects in Florida, Hawaii, Utah, and Colorado. NREL's 2011 technical report on the solar-augment potential of fossil-fired power plants examined regions of the U.S. with ''good solar resource as defined by their direct normal insolation (DNI)'' and identified sixteen states as meeting that criterion: Alabama, Arizona, California, Colorado, Florida, Georgia, Louisiana, Mississippi, Nevada, New Mexico, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, and Utah. The technical report explained that annual average DNI has a significant effect on the performance of a solar-augmented fossil plant, with higher average DNI translating into the ability of a hybrid power plant to produce more steam for augmenting the plant. The technical report used a points-based system and assigned the most points for high solar resource values. An examination of a NREL-generated DNI map of the U.S. reveals that states with the highest DNI values are located in the southwestern U.S., with only portions of Arizona, California, Nevada, New Mexico, and Texas (plus Hawaii) having solar resources that would have been assigned the highest points by the NREL technical report (7 kWh/m2/day or greater).

Commenters supported not incorporating hybrid power plants as part of the BSER, and the EPA is not including hybrid power plants as part of the BSER because of gaps in the EPA's knowledge about costs, and concerns about the cost-effectiveness of the technology, as noted above.

G. Standards of Performance

Once the EPA has determined that a particular system or technology represents BSER, the CAA authorizes the Administrator to establish standards of performance for new units that reflect the degree of emission limitation achievable through the application of that BSER. As noted above, the EPA is finalizing a two-phase set of standards of performance, which reflect a two-component BSER, for base load combustion turbines. Under this approach, for the first phase of the standards, which applies as of the effective date the final rule, the BSER is highly efficient generation and best operating and maintenance practices. During this phase, owners/operators of EGUs will be subject to a numeric standard of performance that is representative of the performance of the best performing EGUs in the subcategory. For the second phase of the standards, beginning in 2035, the BSER for base load turbines includes 90

[865] EIA, Annual Energy Outlook 2018, February 6, 2018. *https://www.eia.gov/outlooks/aeo/.*

[866] B. Alqahtani and D. Patiño-Echeverri, Duke University, Nicholas School of the Environment, ''Integrated Solar Combined Cycle Power Plants: Paving the Way for Thermal Solar,'' Applied Energy 169:927–936 (2016).

percent capture CCS. The affected EGUs will be subject to an emissions rate that reflects continued use of highly efficient generation and best operating and maintenance practices, coupled with CCS. In addition, the EPA is finalizing a single component BSER, applicable from May 23, 2023, for low and intermediate load combustion turbines.

1. Phase-1 Standards

The first component of the BSER is the use of highly efficient combined cycle technology for base load EGUs in combination with the best operating and maintenance practices, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices for intermediate load EGUs, and the use of lower-emitting fuels for low load EGUs.

The EPA proposed that for base load combustion turbines, the first-component BSER supports a standard of 770 lb CO_2/MWh-gross for large natural gas-fired EGUs, *i.e.*, those with a base load rating heat input greater than 2,000 MMBtu/h; 900 lb CO_2/MWh-gross for small natural gas-fired EGUs, *i.e.*, those with a base load rating of 250 MMBtu/h; and between 900 and 770 lb CO_2/MWh-gross, based on the base load rating of the EGU, for natural gas-fired EGUs with base load ratings between 250 MMBtu/h and 2,000 MMBtu/h.[867] The EPA proposed that the most efficient available simple cycle technology—which qualifies as the BSER for intermediate load combustion turbines—supports a standard of 1,150 lb CO_2/MWh-gross for natural gas-fired EGUs. For new and reconstructed low load combustion turbines, the EPA proposed to find that the use of lower-emitting fuels—which qualifies as the BSER—supports a standard that ranges from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu depending on the fuel burned. The EPA proposed these standards to apply at all times and compliance to be determined on a 12-operating month rolling average basis.

The EPA proposed that these standards of performance are achievable specifically for natural gas-fired base load and intermediate load combustion turbine EGUs. However, combustion turbine EGUs burn a variety of fuels, including fuel oil during natural gas curtailments. Owners/operators of combustion turbines burning fuels other than natural gas would not necessarily be able to comply with the proposed standards for base load and intermediate load natural gas-fired combustion turbines using highly efficient generation. Therefore, the Agency proposed that owners/operators of combustion turbines burning fuels other than natural gas may elect to use the ratio of the heat input-based emissions rate of the specific fuel(s) burned to the heat input-based emissions rate of natural gas to determine a source-specific standard of performance for the operating period. For example, the NSPS emissions rate for a large base load combustion turbine burning 100 percent distillate oil during the 12-operating month period would be 1,070 lb CO_2/MWh-gross.[868]

Some commenters stated that the proposed base load emissions standard based on highly efficient generation is not adequately demonstrated, and that site conditions and certain operating parameters are outside of the control of the owner/operator. These commenters explained that the emissions rate of a combustion turbine is dependent on external and site-specific factors, rather than the design efficiency. Factors such as warmer climates, elevation, water conservation measures (*e.g.*, the use of dry cooling), and automatic generation control negatively impacted efficiency. They emphasized that operating units at partial loads would be necessary for maintaining grid reliability, especially as more renewables are incorporated, and the proposed limit is only achievable under ideal operating conditions. Commenters noted that the emission standards should account for start and stop cycles, back-up fuel use, degradation, and compliance tolerance. Commenters stated that the lack of flexibility would force units to operate at nameplate capacity, even when it was unnecessary and could result in increased emissions. In addition, some commenters stated that duct burners could be an alternative to simple cycle turbines for peaking generation, even though they were less efficient than combined cycle turbines without duct burners. They recommended the Agency consider excluding emissions and heat input from duct burners from the emissions standard. Furthermore, commenters noted multiple units that the EPA used in the analysis to support the proposed base load standards were permitted near or above 800 lb CO_2/MWh. Commenters stated that the original equipment manufacturer would not be able to provide a warranty that the proposed 12-month rolling emissions rate is achievable due to the varying operating conditions. Commenters recommended the EPA raise the emissions standard to 850 or 900 lb CO_2/MWh-gross for large base load combustion turbines. In addition, commenters suggested that the EPA incorporate scaling for smaller units to 1,100 lb CO_2/MWh-gross, and the beginning of the sliding scale should be at least 2,500 MMBtu/h.

a. Base Load Phase-1 Emission Standards

Considering the public comments, the EPA re-evaluated the phase-1 standard of performance for base load combustion turbines. To determine the impact of duty cycle and temperature, the EPA binned hourly data by load and season. This allowed the Agency to isolate the impact of ambient temperature and duty cycle separately. The EPA evaluated the impact of ambient temperature by comparing the average emissions for all hours between 70 to 80 percent load during different seasons. For the combined cycle turbines evaluated, the difference between the summer and winter average emission rates was minimal, typically in the single digits and less than a 1 percent difference in emission rates. Since the seasonal temperature differences are much larger than regional variations, the EPA determined that regional ambient temperature has minimal impact on the emissions rate of combined cycle EGUs. Owners/operators of combined cycle EGUs are either using inlet cooling effectively to manage the efficiency losses of the combustion turbine engine or increased generation from the Rankine cycle portion (*i.e.*, HRSG and steam turbine) of the combined cycle turbine is offsetting efficiency losses in the combustion turbine engine.[869] In addition, the variation in emissions rate by load (described below) is much larger than temperature and therefore the operating load is a more important factor than ambient temperature impacting CO_2 emission rates.

Based on the emissions data submitted to the EPA, combined cycle

[867] As proposed, a new small natural gas-fired base load EGU would determine the facility emissions rate by taking the difference in the base load rating and 250 MMBtu/h, multiplying that number by 0.0743 lb CO_2/(MW * MMBtu), and subtracting that number from 900 lb CO_2/MWh-gross. The emissions rate for a natural gas-fired base load combustion turbine with a base load rating of 1,000 MMBtu/h is 900 lb CO_2/MWh-gross minus 750 MMBtu/h (1,000 MMBtu/h–250 MMBtu/h) times 0.0743 lb CO_2/(MW * MMBtu), which results in an emissions rate of 844 lb CO_2/MWh-gross.

[868] The heat input-based emission rates of natural gas and distillate oil are 117 and 163 lb CO_2/MMBtu, respectively. The ratio of the heat input-based emission rates (1.39) is multiplied by the natural gas-fired standard of performance (770 lb CO_2/MWh) to get the applicable emissions rate (1,070 lb CO_2/MWh).

[869] As the efficiency of the combustion turbine engine is reduced at higher ambient temperatures relatively more heat is in the exhaust entering the HRSG. This can increase the output from the steam turbine.

CO_2 emission are lowest at between approximately 80 to 90 percent load. Emission rates are relatively stable at higher loads and down to approximately 70 percent load—typically 1 or 2 percent higher than the lowest emissions rate. Emissions can increase dramatically at lower loads and could impact the ability of an owner/operator to comply with the base load standard. The EPA considered two approaches to address potential compliance issues for owners/operators of base load combustion turbines operating at lower duty cycles. The first approach was to calculate emission rates using only hourly data when the combined cycle turbine was operating at an hourly load of 70 percent or higher. However, this has minimal impact on the calculated base load emissions rate. This is because of 2 reasons. First, the majority of operating hours for base load combustion turbines are at 70 percent load or higher. In addition, the 12-operating month averages are determined by the overall sum of the CO_2 emissions divided by the overall output during the 12-operating month period and not the average of the individual hourly rates. The impact of this approach is that low load hours have smaller impacts on the 12-operating month average relative to high load hours. Therefore, the EPA determined that using only higher load hours to determine the base load emission rates would not address potential issues for owners/operators of base load combustion turbines operating at relative low duty cycles (*i.e.,* low hourly capacity factors).

The second approach the EPA considered, and is finalizing, is estimating the emissions rate of combined cycle turbines at the lower end of the base load threshold—where more hours of low load operation could potentially be included in the 12-operating month average—and establishing a standard of performance that is achievable at lower percent of potential electric sales for the base load subcategory. To determine what emission rates are currently achieved by existing high-efficiency combined cycle EGUs, the EPA reviewed 12-operating month generation and CO_2 emissions data from 2015 through 2023 for all combined cycle turbines that submitted continuous emissions monitoring system (CEMS) data to the EPA's emissions collection and monitoring plan system (ECMPS). The data were sorted by the lowest maximum 12-operating month emissions rate for each unit to identify long-term emission rates on a lb CO_2/MWh-gross basis that have been demonstrated by the existing combined cycle EGU fleets. Since an NSPS is a never-to-exceed standard, the EPA proposed and is finalizing a conclusion that use of long-term data are more appropriate than shorter term data in determining an achievable standard. These long-term averages account for degradation and variable operating conditions, and the EGUs should be able to maintain their current emission rates, as long as the units are properly maintained. While annual emission rates indicate a particular standard is achievable for certain EGUs in the short term, they are not necessarily representative of emission rates that can be maintained over an extended period using highly efficient generating technology in combination with best operating and maintenance practices.

To determine the 12-operating month average emissions rate that is achievable by application of the BSER, the EPA proposed and is finalizing an approach to calculating 12-month CO_2 emission rates by dividing the sum of the CO_2 emissions by the sum of the gross electrical energy output over the same period. The EPA did this separately for combined cycle EGUs and simple cycle EGUs to determine the emissions rate for the base load and intermediate load subcategories, respectively. Commenters generally supported the 12-month rolling average for emission standard compliance.

The average maximum 12-operating month base load emissions rate for large combined cycle turbines that began operation since 2015 is 810 lb CO_2/MWh-gross. The range of the maximum 12-operating month emissions rate for individual units is 720 to 920 lb CO_2/MWh-gross. The lowest emissions rate was achieved by an individual unit at the Okeechobee Clean Energy Center. This facility is a large 3-on-1 combined cycle EGU that commenced operation in 2019 and uses a recirculating cooling tower for the steam cycle. Each turbine is rated at 380 MW and the three HRSGs feed a single steam turbine of 550 MW. The EPA did not propose to use the emissions rate of this EGU to determine the standard of performance for multiple reasons. The Okeechobee Clean Energy Center uses a 3-on-1 multi-shaft configuration but, many combined cycle EGUs use a 1-on-1 configuration. Combined cycle EGUs using a 1-on-1 configuration can be designed such that both the combustion turbine and steam turbine are arranged on one shaft and drive the same generator. This configuration has potential capital cost and maintenance costs savings and a smaller plant footprint that can be particularly important for combustion turbines enclosed in a building. In addition, a single shaft configuration has higher net efficiencies when operated at part load than a multi-shaft configuration. Basing the standard of performance strictly on the performance of multi-shaft combined cycle EGUs could limit the ability of owners/operators to construct new combined cycle EGUs in space-constrained areas (typically urban areas [870]) and combined cycle EGUs with the best performance when operated as intermediate load EGUs.[871] Either of these outcomes could result in greater overall emissions from the power sector. An advantage of multi-shaft configurations is that the turbine engine can be installed initially and run as a simple cycle EGU, with the HRSG and steam turbines added at a later date, all of which allows for more flexibility for the regulated community. In addition, a single large steam turbine in a 2–1 or 3–1 configuration can generate electricity more efficiently than multiple smaller steam turbines, increasing the overall efficiency of comparably sized combined cycle EGUs. According to Gas Turbine World 2021, multi-shaft combined cycle EGUs have design efficiencies that are 0.7 percent higher than single shaft combined cycle EGUs using the same turbine engine.[872]

The efficiency of the Rankine cycle (*i.e.,* HRSG plus the steam turbine) is determined in part by the ability to cool the working fluid (*e.g.,* steam) after it has been expanded through the turbine. All else equal, the lower the temperature that can be achieved, the more efficient the Rankine cycle. The Okeechobee Clean Energy Center used a recirculating cooling system, which can achieve lower temperatures than EGUs using dry cooling systems and therefore would be more efficient and have a lower emissions rate. However dry cooling systems have lower water requirements and therefore could be the preferred technology in arid regions or

[870] Generating electricity closer to electricity demand can reduce stress on the electric grid, reducing line losses and freeing up transmission capacity to support additional generation from variable renewable sources. Further, combined cycle EGUs located in urban areas could be designed as CHP EGUs, which have potential environmental and economic benefits.

[871] Power sector modeling projects that combined cycle EGUs will operate at lower capacity factors in the future. Combined cycle EGUs with lower base load efficiencies but higher part load efficiencies could have lower overall emission rates.

[872] According to the data in Gas Turbine World 2021, while there is a design efficiency advantage of going from a 1-on-1 configuration to a 2-on-1 configuration (assuming the same turbine engine), there is no efficiency advantage of 3-on-1 configurations compared to 2-on-1 configurations.

in areas where water requirements could have significant ecological impacts. Therefore, the EPA proposed and is finalizing that the efficient generation standard for base load EGUs should account for the use of cooling technologies with reduced water requirements.

Finally, the Okeechobee Clean Energy Center operates primarily at high duty cycles where efficiency is the highest and since it is a relatively new facility efficiency degradation might not be accounted for in the emissions analysis. Therefore, the EPA is not determining that the performance of the Okeechobee Clean Energy Facility is appropriate for a nationwide standard.

The proposed emissions rate of 770 lb CO_2/MWh-gross has been demonstrated by approximately 15 percent of recently constructed large combined cycle EGUs. As noted in the proposal, these combustion turbines include combined cycle EGUs using 1-on-1 configurations, dry cooling, and combustion turbines on the lower end of the large base load subcategory. In addition, this emissions rate has been demonstrated by using combustion turbines from multiple manufacturers and from one facility that commenced operation in 2011—demonstrating the long-term achievability of the proposed emissions standard. However, as noted by commenters the majority of recently constructed combined cycle turbines are not achieving an emissions rate of 770 lb CO_2/MWh-gross and combustion turbine manufacturers might not be willing to guarantee this emissions level in operating making it challenging to build a new combined cycle EGU.

To account for differences in the performance of the best performing combustion turbines and design options that result in less efficient operation, the EPA normalized the reported emission rates for combined cycle EGUs.[873] Specifically, for the reported emissions rates of combined cycle turbines with cooling towers was increased by 1.0 percent to account for potential new units using dry cooling. Similarly, the emissions rate of 2–1 and 3–1 combined cycle turbines were increased by 1.4 percent to account for potential new units using a 1–1 configuration. In addition, for the best performing combined cycle turbines, the EPA plotted the 12-operating month emissions rate against the 12-operating month heat input-based capacity factor. Based on this data, the EPA used the trend in increasing emission rates at lower 12-operating month capacity factors to estimate the emissions rate at capacity factors at which an individual facility has never operated. This approach allowed the EPA to estimate the emissions rate at a 40 percent 12-operating month capacity factor for the best performing combined cycle turbines. This allows the estimation of the emissions rate at the lower end of the base load subcategory using higher capacity factor data.[874] The EPA did not correct the achievable emissions rate for combined cycle turbines where the relationship indicated emission rates declined at lower 12-operating month capacity factors.

As noted in the proposal, one of the best performing large combined cycle EGUs that has maintained a 12-operating-month base load emissions rate of 770 lb CO_2/MWh-gross is the Dresden plant, located in Ohio.[875] This 2-on-1 combined cycle facility uses a recirculating cooling tower. The turbine engines are rated at 2,250 MMBtu/h, which demonstrates that the standard of performance for large base load combustion turbines is achievable at a heat input rating of 2,000 MMBtu/h. As noted, a 2-on-1 configuration and a cooling tower are more efficient than a 1-on-1 configuration and dry cooling. Normalizing for these factors and accounting for operation at a 12-operating month capacity factor of 40 percent increases the achievable demonstrated emissions rate to 800 lb CO_2/MWh-gross. However, the Dresden Energy Facility does not use the most efficient combined cycle design currently available. Multiple more efficient designs have been developed since the Dresden Energy Facility commenced operation a decade ago that more than offset these efficiency losses. Therefore, the EPA has determined that the Dresden combined cycle EGU demonstrates that an emissions rate of 800 lb CO_2/MWh-gross is achievable for all new large combined cycle EGUs with an acceptable compliance margin. Therefore, the EPA is finalizing a phase 1 standard of performance of 800 lb CO_2/MWh-gross for large base load combustion turbines (*i.e.*, those with a base load rating heat input greater than 2,000 MMBtu/h) based on the BSER of highly efficient combined cycle technology.

With respect to small combined cycle combustion turbines, the best performing unit identified by the EPA is the Holland Energy Park facility in Holland, Michigan, which commenced operation in 2017 and uses a 2-on-1 configuration and a cooling tower.[876] The 50 MW turbine engines have individual heat input ratings of 590 MMBtu/h and serve a single 45 MW steam turbine. The facility has maintained a 12-operating month, 99 percent confidence emissions rate of 870 lb CO_2/MWh-gross. The emissions standard for a base load combustion turbine of this size is 880 lb CO_2/MWh-gross. The normalized emissions rate accounting for the use of recirculating cooling towers, a 2–1 configuration, and operation at a 40 percent capacity factor is 900 lb CO_2/MWh-gross. While this is higher than the final emissions standard in this rule, there are efficient generation technologies that are not being used at the Holland Energy Park. For example, a commercially available HRSG that uses supercritical CO_2 instead of steam as the working fluid is available. This HRSG would be significantly more efficient than the HRSG that uses dual pressure steam, which is common for small combined cycle EGUs.[877] When these efficiency improvements are accounted for, a similar combined cycle EGU would be able to maintain an emissions rate of 880 lb CO_2/MWh-gross. In addition, the normalization approach assumes a worst-case scenario. Hybrid cooling technologies are available and offer performance similar to that of wet cooling towers. This long-term data accounts for degradation and variable operating conditions and demonstrates that a base load combustion turbine EGU with a turbine rated at 590 MMBtu/h should be able to maintain an emissions rate of 880 lb CO_2/MWh-gross.[878] Therefore, estimating that

[873] A similar normalization approach was used by the EPA in previous EGU GHG NSPS rulemakings to benchmark the performance of coal-fired EGUs when determining an achievable efficiency-based standard of performance.

[874] The most efficient combined cycle turbines tend to operate strictly as base load combustion turbines, well above the base load subcategorization threshold.

[875] The Dresden Energy Facility is listed as being located in Muskingum County, Ohio, as being owned by the Appalachian Power Company, as having commenced commercial operation in late 2011. The facility ID (ORISPL) is 55350 1A and 1B.

[876] The Holland Park Energy Center is a CHP system that uses hot water in the cooling system for a snow melt system that uses a warm water piping system to heat the downtown sidewalks to clear the snow during the winter. Since this useful thermal output is low temperature, it likely only results in a small reduction of the electrical efficiency of the EGU. If the useful thermal output were accounted for, the emissions rate of the Holland Energy Park would be lower. The facility ID (ORISPL) is 59093 10 and 11.

[877] If the combustion turbine engine exhaust temperature is 500 °C or greater, a HRSG using 3 pressure steam without a reheat cycle could potentially provide an even greater increase in efficiency (relative to a HRSG using 2 pressure steam without a reheat cycle).

[878] To estimate an achievable emissions rate for an efficient combined cycle EGU at 250 MMBtu/h

Continued

emission rates will be slightly higher for smaller combustion turbines, the EPA is finalizing a phase 1 standard of performance of 900 lb CO_2/MWh-gross for small base load combustion turbines (*i.e.*, those with a base load rating of 250 MMBtu/h) based on the BSER of highly efficient combined cycle technology.

b. Intermediate Load Emission Standards

For the intermediate load standards of performance, some commenters stated that an emissions standard of 1,150 lb CO_2/MWh-gross is only achievable for simple cycle except under ideal operating conditions. Since the emissions standard is not achievable in practice, these commenters stated that the majority of new simple cycle turbines would be prevented from operating as variable or intermediate load units. Similar to comments on the base load emissions standard, commenters stated the standard of performance should account for ambient conditions, operation at part load, automatic generation control, and variable loads. If the intermediate load standard is not achievable in practice, it could result in the operation of less efficient generation in other operating modes and an increase in overall GHG emissions. They also explained this could force simple cycle turbines to always operate at nameplate capacity, even when it was not necessary, which would also lead to increased emissions. These commenters requested that the EPA raise the variable and intermediate load emissions standard to 1,250 to 1,300 lb CO_2/MWh-gross.

Considering the public comments, the EPA re-evaluated the standard of performance for intermediate load combustion turbines using the same approach as for combined cycle turbines, except using the performance of simple cycle EGUs. The average maximum 12-operating operating month intermediate load emissions rate for simple cycle turbines that began operation since 2015 is 1,210 lb CO_2/MWh-gross. The range of the maximum 12-operating month emissions rate for individual units is 1,080 to 1,470 lb CO_2/MWh-gross. The lowest emissions rate was achieved by an individual unit at the Scattergood Generating Station. This facility includes 2 large aeroderivative simple cycle turbines (General Electric LMS 100) that commenced operation in 2015. Each turbine is rated at approximately 100 MW and use water injection to reduce NO_X emissions. The EPA did not propose and is not finalizing to use the emissions rate of this EGU to determine the standard of performance for multiple reasons. Simple cycle turbine efficiency tends to increase with size and the simple cycle turbines at the Scattergood Facility are the largest aeroderivative turbines available. Establishing a standard of performance based on emission rates that only large aeroderivative turbines could achieve would limit the ability to develop new firm combustion turbine based generating capacity in smaller than 100 MW increments. This could result in the local electric grid operating in a less overall efficient manner, increasing overall GHG emissions. In addition, the largest available aeroderivative simple cycle turbines can use either water injection or dry low NO_X combustion to reduce emissions of NO_X. For this particular design, the use of water injection has higher design efficiencies than the dry low NO_X option. Water injection has similar ecological impacts as water used for cooling towers, the EPA has determined in this case it is important to preserve the option for new intermediate load combustion turbines to use dry low NO_X combustion.

The proposed emissions rate of 1,150 lb CO_2/MWh-gross was achieved by 20 percent of recently constructed intermediate load simple cycle turbines. However, only two-thirds of LMS 100 simple cycle turbines installed to date have maintained an intermediate load emissions rate of 1,150 lb CO_2/MWh-gross. In addition, only one-third of the Siemens STG–A65 simple cycle turbines and only 10 percent of General Electric LM6000 simple cycle combustion turbine have maintained this emissions rate. Both of these are common aeroderivative turbines and since they do require an intercooler have potential space consideration advantages compared to the LMS100. Finalizing the proposed emissions standard could restrict new intermediate load simple cycle turbine to the use of intercooling, limiting application to locations that can support a cooling tower. An intermediate load emissions rate of 1,170 lb CO_2/MWh-gross has been achieved by three-quarters of both the LMS100 and STG–A65 installations and 20 percent of LM6000 installations. In addition, this emissions rate has been demonstrated by a frame simple turbine. The EPA notes that the more efficient versions of the combustion turbines—water injection in the case of the LMS 100 and DLN in the case of the STG–A65—have higher design efficiencies and higher compliance levels than the version with the alternate NO_X control technology. This standard of performance has been demonstrated by 40 percent of recently installed intermediate load simple cycle turbines and the Agency has determined that with proper maintenance is achievable with combustion turbines from multiple manufacturers, with and without intercooling, and is finalizing a standard of 1,170 lb CO_2/MWh-gross for intermediate load combustion turbines. The EPA considered, but rejected, finalizing an emissions standard of 1,190 lb CO_2/MWh-gross. This standard of performance has been achieved by essentially all LMS 100 and SGT–A65 intermediate load simple cycle turbines and 70 percent of recently installed intermediate load simple cycle turbines but would not require the most efficient available versions of new intermediate load simple cycle turbines and does not represent the BSER.

2. Phase-2 Standards

The EPA proposed that 90 percent CCS (as part of the CCS pathway) qualifies as the second component of the BSER for base load combustion turbines. For the base load combustion turbines, the EPA reduced the emissions rate by 89 percent to determine the CCS based phase-2 standards.[879] The CCS percent reduction is based on a CCS system capturing 90 percent of the emitting CO_2 being operational anytime the combustion turbine is operating. Similar to the phase-1 emission standards, the EPA proposed and is finalizing a decision that standard of performance for base load combustion turbines be adjusted based on the uncontrolled emission rates of the fuels relative to natural gas. For 100 percent distillate oil-fired combustion turbines, the emission rates would be 120 lb CO_2/MWh-gross.

The EPA solicited comment on the range of reduction in emission rate of 75 to 90 percent. In addition, the EPA solicited comment on whether carbon capture equipment has lower availability/reliability than the combustion turbine or the CCS equipment takes longer to startup than the combustion turbine itself there would be periods of operation where the CO_2 emissions would not be controlled by the carbon capture equipment. For the same reasons as for coal-fired EGUs, the EPA has determined 90 percent CCS

the EPA assumed a linear relationship for combined cycle efficiency with turbine engines with base load ratings of less than 2,000 MMBtu/h.

[879] The 89 percent reduction from CCS accounts for the increased auxiliary load of a 90 percent post combustion amine-based capture system. Due to rounding, the proposed numeric standards of performance do not necessarily match the standards that would be determined by applying the percent reduction to the phase-1 standards.

has been demonstrated and appropriate for base load combustion turbines, see section VII.C.

H. Reconstructed Stationary Combustion Turbines

All the major manufacturers of combustion turbines sell upgrade packages that increase both the output and efficiency of existing combustion turbines. An owner/operator of a reconstructed combustion turbine would be able to use one of these upgrade packages to comply with the intermediate load emission standards in this final rule. Some examples of these upgrades include GE's Advanced Gas Path, Siemens' Hot Start on the Fly, and Solar Turbines' Gas Compressor Restaging. The Advanced Gas Path option includes retrofitting existing turbine components with improved materials to increase durability, air sealing, and overall efficiency.[880] Hot Start on the Fly upgrades include implementing new software to allow for the gas and steam turbine to start-up simultaneously, which greatly improves start times, and in some cases could do so by up to 20 minutes.[881] Compressor restaging involves analyzing the current operation of an existing combustion turbine and adjusting its gas compressor characteristics including transmission, injection, and gathering, to operate in the most efficient manner given the other operating conditions of the turbine.[882] In addition, steam injection is a retrofittable technology that is estimated to be available for a total cost of all the equipment needed for steam injection of $250/kW.[883] Due to the differences in materials used and necessary additional infrastructure, a steam injection system can be up to 60 percent smaller than a similar HRSG, which is valuable for retrofit purposes.[884]

For owners/operators of base load combustion turbines, however, HRSG have been added to multiple existing simple cycle turbines to convert to combined cycle technology. There have been multiple examples of this kind of conversion from simple cycle to combined cycle. One such example is Unit 12 at Riverton Power Plant in Riverton, Kansas, which was originally built in 2007 as a 143 MW simple cycle combustion turbine. In 2013, an HRSG and additional equipment was added to convert Unit 12 to a combined cycle combustion turbine.[885] Another is Energy Center Dover, located in Dover, Delaware, which in addition to a coal-fired steam turbine, originally had two 44 MW simple cycle combustion turbines. Also in 2013, the unit added an HRSG to one of the existing simple cycle combustion turbines, connected the existing steam generator to it, and retired the remaining coal-related equipment to convert that combustion turbine to a combined cycle one.[886] Some other examples include the Los Esteros Critical Energy Facility in San Jose, California, which converted from a four-turbine simple cycle peaking facility to a combined-cycle one in 2013, and the Tracy Combined Cycle Power Plant.[887] The Tracy facility, located in Tracy, California, was built in 2003 with two simple cycle combustion turbines and in 2012 was converted to combined cycle with the addition of a steam turbine.[888]

In the previous sections, the EPA explained the background of and requirements for new and reconstructed stationary combustion turbines and evaluated various control technology configurations to determine the BSER. Because the BSER is the same for new and reconstructed stationary combustion turbines, the Agency used the same emissions analysis for both new and reconstructed stationary combustion turbines. For each of the subcategories, the EPA proposed and is finalizing a conclusion that the BSER results in the same standard of performance for new stationary combustion turbines and reconstructed stationary combustion turbines. For CCS, consistent with the NETL Combined Cycle CCS Retrofit Report, the EPA approximated the cost to add CCS to a reconstructed combustion turbine by increasing the capital costs of the carbon capture equipment by 9 percent relative to the costs of adding CCS to a newly constructed combustion turbine and decreasing the net efficiency by 0.3 percent.[889] Using the same costing assumptions for newly constructed combined cycle turbines, the compliance costs for reconstructed combined cycle turbines are approximately 10 percent higher than for comparable newly constructed combined cycle turbine. Assuming continued operation of the capture equipment, the compliance costs are $17/MWh and $51/ton ($56/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $21/MWh and $63/ton ($69/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. If the capture system is not operated while the combustion turbine is subcategorized as in intermediate load combustion turbine, the compliance costs are reduced to $10/MWh and $50/ton ($55/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $13/MWh and $67/ton ($73/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine.

A reconstructed stationary combustion turbine is not required to meet the standards if doing so is deemed to be "technologically and economically" infeasible.[890] This provision requires a case-by-case reconstruction determination in the light of considerations of economic and technological feasibility. However, this case-by-case determination considers the identified BSER, as well as technologies the EPA considered, but rejected, as BSER for a nationwide rule. One or more of these technologies could be technically feasible and of reasonable cost, depending on site-specific considerations and if so, would likely result in sufficient GHG reductions to comply with the applicable reconstructed standards. Finally, in some cases, equipment upgrades, and best operating practices would result in sufficient reductions to achieve the reconstructed standards.

I. Modified Stationary Combustion Turbines

CAA section 111(a)(4) defines a "modification" as "any physical change in, or change in the method of operation of, a stationary source" that either "increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted." Certain types of physical or operational changes are exempt from consideration as a modification. Those are described in 40 CFR 60.2, 60.14(e).

In the 2015 NSPS, the EPA did not finalize standards of performance for stationary combustion turbines that conduct modifications; instead, the EPA concluded that it was prudent to delay

[880] *https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/advanced-gas-path-brochure.pdf.*

[881] *https://www.siemens-energy.com/global/en/home/stories/trianel-power-plant-upgrades.html.*

[882] *https://s7d2.scene7.com/is/content/Caterpillar/CM20191213-93d46-8e41d.*

[883] "GTI" (2019). Innovative Steam Technologies. *https://otsg.com/industries/powergen/gti/.*

[884] Ibid.

[885] *https://www.nsenergybusiness.com/news/newsempire-district-starts-riverton-plants-combined-cycle-expansion-231013/.*

[886] *https://news.delaware.gov/2013/07/26/repowered-nrg-energy-center-dover-unveiled-gov-markell-congressional-delegation-dnrec-sec-omara-other-officials-join-with-nrg-to-announce-cleaner-natural-gas-facility/.*

[887] *https://www.calpine.com/los-esteros-critical-energy-facility.*

[888] *https://www.middleriverpower.com/#portfolio.*

[889] "Cost and Performance of Retrofitting NGCC Units for Caron Capture—Revision 3." DOE/NETL–2023/3845. March 17, 2023.

[890] 40 CFR 60.15(b)(2).

issuing standards until the Agency could gather more information (80 FR 64515; October 23, 2015). There were several reasons for this determination: few sources had undertaken NSPS modifications in the past, the EPA had little information concerning them, and available information indicated that few owners/operators of existing combustion turbines would undertake NSPS modifications in the future; and since the Agency eliminated proposed subcategories for small EGUs in the 2015 NSPS, questions were raised as to whether smaller existing combustion turbines that undertake a modification could meet the final performance standard of 1,000 lb CO_2/MWh-gross.

It continues to be the case that the EPA is aware of no evidence indicating that owners/operators of combustion turbines intend to undertake actions that could qualify as NSPS modifications in the future. The EPA did not propose or solicit comment on standards of performance for modifications of combustion turbines and is not establishing any in this final rule.

J. Startup, Shutdown, and Malfunction

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the D.C. Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that the SSM exemption violates the requirement under section 302(k) of the CAA that some CAA section 112 standard apply continuously. The EPA has determined the reasoning in the court's decision in *Sierra Club* v. *EPA* applies equally to CAA section 111 because the definition of emission or standard in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS. Consistent with *Sierra Club* v. *EPA,* the EPA is finalizing standards in this rule that apply at all times. The NSPS general provisions in 40 CFR 60.11(c) currently exclude opacity requirements during periods of startup, shutdown, and malfunction and the provision in 40 CFR 60.8(c) contains an exemption from non-opacity standards. These general provision requirements would automatically apply to the standards set in an NSPS, unless the regulation specifically overrides these general provisions. The NSPS subpart TTTT (40 CFR part 60, subpart TTTT) does not contain an opacity standard, thus, the requirements at 40 CFR 60.11(c) are not applicable. The NSPS subpart TTTT also overrides 40 CFR 60.8(c) in table 3 and requires that sources comply with the standard(s) at all times. In reviewing NSPS subpart TTTT and proposing the new NSPS subpart TTTTa, the EPA proposed to retain in subpart TTTTa the requirements that sources comply with the standard(s) at all times in table 3 of the new subpart TTTTa to override the general provisions for SSM exemption related provisions. The EPA proposed and is finalizing that all standards in subpart TTTTa apply at all times.

In developing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained in this section of the preamble, is not establishing alternate standards for those periods. The EPA analysis of achievable standards of performance used CEMS data that includes all period of operation. Since periods of startup, shutdown, and malfunction were not excluded from the analysis, the EPA is not establishing alternate standard for those periods of operation.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment. (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in caselaw requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through "the application of the best system of emission reduction" that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting standards of performance, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a "normal or usual manner" and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting "achievable" standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).

K. Testing and Monitoring Requirements

Because the NSPS reflects the application of the best system of emission reduction under conditions of proper operation and maintenance, in doing the NSPS review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the NSPS. This section includes a discussion on the current testing and monitoring requirements of the NSPS and any additions the EPA is including in 40 CFR part 60, subpart TTTTa.

1. General Requirements

The EPA proposed to allow three approaches for determining CO_2 emissions: a CO_2 CEMS and stack gas flow monitor; hourly heat input, fuel characteristics, and F factors [891] for EGUs firing oil or gas; or Tier 3 calculations using fuel use and carbon content. The first two approaches are in use for measuring CO_2 by units affected by the Acid Rain program (40 CFR part 75), to which most, if not all, of the EGUs affected by NSPS subpart TTTT are already subject, while the last approach is in use for stationary fuel combustion sources reporting to the GHGRP (40 CFR part 98, subpart C).

The EPA believes continuing the use of approaches already in use by other programs represents a cost-effective means of obtaining quality assured data requisite for determining carbon dioxide mass emissions. MPS reporting software required by this subpart for reporting emissions to the EPA expects hourly or daily CO_2 emission values and has thousands of electronic checks to validate data using the Acid Rain program requirements (40 CFR part 75). ECMPS does not currently accommodate or validate data under GHGRP's Tier 3 approach. Because most, if not all, of the EGUs that will be affected by this final rule are already affected by Acid Rain program monitoring requirements, the cost and burden for EGU owners or operators are already accounted for by other rulemakings. Therefore, this aspect of the final rule is designed to have minimal, if any, cost or burden associated with CO_2 testing and monitoring. In addition, there are no changes to measurement and testing requirements for determining electrical output, both gross and net, as well as

[891] An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel.

thermal output, to existing requirements.

However, the EPA requested comment on whether continuous CO_2 CEMS and stack gas flow measurements should be the sole means of compliance for this rule. Such a switch would increase costs for those EGU owners or operators who are currently relying on the oil- or gas-fired calculation-based approaches. By way of reference, the annualized cost associated with adoption and use of continuous CO_2 and flow measurements where none now exist is estimated to be about $52,000. To the extent that the rule were to mandate continuous CO_2 and stack gas flow measurements in accordance with what is currently allowed as one option and that an EGU lacked this instrumentation, its owner or operator would need to incur this annual cost to obtain such information and to keep the instrumentation calibrated. Commenters encouraged the EPA to maintain the flexibility for EGUs to use hourly heat input measurements, fuel characteristics, and F factors as is allowed under the Acid Rain program. Commenters argued that in addition to the incremental costs, some facilities have space constraints that could make the addition of stack gas flow monitors difficult or impractical. In this final rule, the EPA allows the use of hourly heat input, fuel characteristics, and F factors as an alternative to CO_2 CEMS and stack gas flow monitors for EGUs that burn oil or gas.

One commenter argued that the part 75 data requirements, which are required for several emission trading programs including the Acid Rain program, are punitive and that the data are biased high. Other commenters argued that the part 75 CO_2 data are biased low. EPA disagrees that the data requirements are punitive. Most, if not all, of the EGUs subject to this subpart are already reporting the data under the Acid Rain program. Oil- and gas-fired EGUs that are not subject to the Acid Rain program but are subject to a Cross-State Air Pollution Rule program are already reporting most of the necessary data elements (*e.g.*, hourly heat input and F factors) for SO_2 and/or NO_X emissions. The additional data and effort necessary to calculate CO_2 emissions is minor. The EPA also disagrees that the data are biased significantly high or low. Each CO_2 CEMS and stack gas flow monitor must undergo regular quality assurance and quality control activities including periodic relative accuracy test audits where the EGU's monitoring system is compared to an independent monitoring system. In a May 2022 study conducted by the EPA, the average difference between the EGU's monitoring system and the independent monitoring system was approximately 2 percent for CO_2 concentration and slightly greater than 2 percent for stack gas flow.

2. Requirements for Sources Implementing CCS

The CCS process is also subject to monitoring and reporting requirements under the EPA's GHGRP (40 CFR part 98). The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the U.S. The ''suppliers of carbon dioxide'' source category of the GHGRP (GHGRP subpart PP) requires those affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied. Facilities that inject a CO_2 stream underground for long-term containment in subsurface geologic formations report quantities of CO_2 sequestered under the ''geologic sequestration of carbon dioxide'' source category of the GHGRP (GHGRP subpart RR). In April 2024, to complement GHGRP subpart RR, the EPA finalized the ''geologic sequestration of carbon dioxide with enhanced oil recovery (EOR) using ISO 27916'' source category of the GHGRP (GHGRP subpart VV) to provide an alternative method of reporting geologic sequestration in association with EOR.[892 893 894]

CCS as the BSER, as detailed in section VIII.F.4.c.iv of this preamble, is determined to be adequately demonstrated based solely on geologic sequestration that is not associated with EOR. However, EGUs also have the compliance option to send CO_2 to EOR facilities that report under GHGRP subpart RR or GHGRP subpart VV. The EPA is requiring that any affected unit that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the captured CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility that reports in accordance with GHGRP subpart RR or GHGRP subpart VV. This does not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC program under the Safe Drinking Water Act.

The EPA also notes that compliance with the standard is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic sequestration site are not part of that calculation, though the EPA anticipates that the quantity of CO_2 sequestered will be substantially similar to the quantity captured. However, to verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, the Agency is leveraging regulatory reporting requirements under the GHGRP. The EPA also emphasizes that this final rule does not involve regulation of downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. The requirement that the emitting EGU transfer the captured CO_2 to an entity subject to the GHGRP requirements is thus exclusively an element of enforcement of the EGU standard. This avoids duplicative monitoring, reporting, and verification requirements between this rule and the GHGRP, while also ensuring that the facility injecting and sequestering the CO_2 (which may not necessarily be the EGU) maintains responsibility for these requirements. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of this final rule.

L. Recordkeeping and Reporting Requirements

The current rule (subpart TTTT of 40 CFR part 60) requires EGU owners or operators to prepare reports in accordance with the Acid Rain Program's ECMPS. Such reports are to be submitted quarterly. The EPA believes all EGU owners and operators have extensive experience in using the ECMPS and use of a familiar system ensures quick and effective rollout of the program in this final rule. Because all EGUs are expected to be covered by and included in the ECMPS, minimal, if any, costs for reporting are expected for

[892] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[893] International Standards Organization (ISO) standard designated as CSA Group (CSA)/American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (referred to as ''CSA/ANSI ISO 27916:2019'').

[894] As described in 87 FR 36920 (June 21, 2022), both subpart RR and subpart VV (CSA/ANSI ISO 27916:2019) require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. Primary differences relate to the terms in their respective mass balance equations, how each defines leakage, and when facilities may discontinue reporting.

this final rule. In the unlikely event that a specific EGU is not already covered by and included in the ECMPS, the estimated annual per unit cost would be about $8,500.

The current rule's recordkeeping requirements at 40 CFR part 60.5560 rely on a combination of general provision requirements (see 40 CFR 60.7(b) and (f)), requirements at subpart F of 40 CFR part 75, and an explicit list of items, including data and calculations; the EPA is retaining those existing subpart TTTT of 40 CFR part 60 requirements in the new NSPS subpart TTTTa of 40 CFR part 60. The annual cost of those recordkeeping requirements will be the same amount as is required for subpart TTTT of 40 CFR part 60 recordkeeping. As the recordkeeping in subpart TTTT of 40 CFR part 60 will be replaced by similar recordkeeping in subpart TTTTa of 40 CFR part 60, this annual cost for recordkeeping will be maintained.

M. Compliance Dates

Owners/operators of affected sources that commenced construction or reconstruction after May 23, 2023, must meet the requirements of 40 CFR part 60, subpart TTTTa, upon startup of the new or reconstructed affected facility or the effective date of the final rule, whichever is later. This compliance schedule is consistent with the requirements in section 111 of the CAA.

N. Compliance Date Extension

Several industry commenters noted the potential for delay in installation and utilization of emission controls—especially CCS—due to supply chain constraints, permitting challenges, environmental assessments, or delays in development of necessary infrastructure, among other reasons. Commenters requested that the EPA include a mechanism to extend the compliance date for affected EGUs that are installing emission controls. These commenters explained that an extension mechanism could provide greater regulatory certainty for owners and operators.

After considering these comments, the EPA believes that it is reasonable to provide a consistent and transparent means of allowing a limited extension of the Phase 2 compliance deadline where an affected new or reconstructed base load stationary combustion EGU has demonstrated such an extension is needed for installation and utilization of controls. This mechanism is intended to address unavoidable delays in implementation—not to provide more time to assess the NSPS compliance strategy for the affected EGU.

As indicated, the EPA is finalizing a provision that will allow the owner/operators of new or reconstructed base load stationary combustion turbine EGUs to request a limited Phase 2 compliance extension based on a case-by-case demonstration of necessity. Under these provisions, the owner or operator of an affected source may apply for a Phase 2 compliance date extension of up to 1 year to comply with the applicable emissions control requirements, which if approved by the EPA, would require compliance with Phase 2 standards of performance no later than January 1, 2033. This mechanism is only available for situations in which an affected source encounters a delay in installation or startup of a control technology that makes it impossible to commence compliance with Phase 2 standards of performance by January 1, 2032 (*i.e.*, the Phase 2 compliance date specified in section VIII.F.4 of this preamble).

The EPA will grant a request for a Phase 2 compliance extension of up to 1 year only where a source demonstrates that it has taken all steps possible to install and start up the necessary controls and still cannot comply with the Phase 2 standards of performance by the January 1, 2032 compliance date due to circumstances entirely beyond its control. Any request for a Phase 2 compliance extension must be received by the EPA at least 180 days before the January 1, 2032 Phase 2 compliance date. The owner/operator of the requesting source must provide documentation of the circumstances that precipitated the delay (or an anticipated delay) and demonstrate that those circumstances are entirely beyond the control of the owner/operator and that the owner/operator has no ability to remedy the delay. These circumstances may include, but are not limited to, delays related to permitting, delays in delivery or construction of parts necessary for installation or implementation of the control technology, or development of necessary infrastructure (*e.g.*, CO_2 pipelines).

The request must include documentation that demonstrates that the necessary controls cannot be installed or started up by the January 1, 2032 Phase 2 compliance date. This may include information and documentation obtained from a control technology vendor or engineering firm demonstrating that the necessary controls cannot be installed or started up by the applicable Phase 2 compliance date, documentation of any permit delays, or documentation of delays in construction or permitting of infrastructure (*e.g.*, CO_2 pipelines) that is necessary for implementation of the control technology. The owner/operator of an affected new stationary combustion turbine EGU remains subject to the January 1, 2032 Phase 2 compliance date unless and until the Administrator grants a compliance extension.

As discussed in sections VII.C.1.a.i.(E) and VII.C.2.b.i(C), the EPA has determined compliance timelines for these new sources that are consistent with achieving emission reductions as expeditiously as practicable given the time it takes to install and startup the BSER technologies for compliance with the Phase 2 standards of performance. The Phase 2 compliance dates are designed to accommodate the process steps and timeframes that the EPA reasonably anticipates will apply to affected EGUs. This extension mechanism acknowledges that circumstances entirely outside the control of the owners or operators of affected EGUs may extend the timeframe for installation or startup of control technologies beyond the timeframe that the EPA has determined is reasonable as a general matter. Thus, so long as this extension mechanism is limited to circumstances that cannot be reasonably controlled or remedied by the owners or operators of the affected EGUs and that make it impossible to achieve compliance with Phase 2 standards of performance by the January 1, 2032 compliance date, its use is consistent with achieving compliance as expeditiously as practicable.

The EPA believes that a 1-year extension on top of the lead time already provided by the 2032 compliance date should be sufficient to address any compliance delays and to allow all base load units to timely install CSS. New or reconstructed base load stationary combustion turbines that are granted a 1-year Phase 2 compliance date extension and still are not able to install or startup the control technologies necessary to meet the Phase 2 standard of performance by the extended Phase 2 compliance date of January 1, 2033 may adjust their operation to the intermediate load subcategory (*i.e.*, 12-operating-month capacity factor between 20–40 percent). Such sources must then comply with applicable standards of performance for the intermediate load stationary combustion turbine subcategory until the necessary controls are installed and operational such that the source can comply with the Phase 2 standard of performance.

IX. Requirements for New, Modified, and Reconstructed Fossil Fuel-Fired Steam Generating Units

A. 2018 NSPS Proposal Withdrawal

1. Background

As discussed in section V.B, the EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015 (''2015 NSPS'').[895] The 2015 NSPS finalized partial CCS as the BSER and finalized standards of performance to limit emissions of GHG manifested as CO_2 from newly constructed, modified, and reconstructed fossil fuel-fired EGUs (*i.e.*, utility boilers and integrated gasification combined cycle (IGCC) units). In the same document, the Agency also finalized CO_2 emission standards for newly constructed and reconstructed stationary combustion turbine EGUs. 80 FR 64510 (October 23, 2015). These final standards were codified in 40 CFR part 60, subpart TTTT.

On December 20, 2018, the EPA published a proposal to revise certain parts of the 2015 Rule, titled ''Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.'' 83 FR 65424 (December 20, 2018) (''2018 Proposal''). In Fall 2020, after reviewing comments on the 2018 Proposal, the EPA developed a draft final rule and sent that package to the Office of Management and Budget (OMB) for interagency review under Executive Order 12866 (''2020 OMB Review Package''). The 2020 OMB Review Package, if finalized, would have amended the BSER for new coal-fired EGUs and required a pollutant-specific significant contribution finding (SCF) prior to regulating a source category. The review of the BSER portion of the package was delayed [896] and the pollutant-specific SCF portion of the 2020 OMB Review Package was finalized on January 13, 2021 in a final rule, titled ''Pollutant-Specific Contribution Finding for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories.'' 86 FR 2542 (January 13, 2021) (''SCF Rule''). However, the D.C. Circuit vacated the SCF Rule on April 5, 2021.[897] The BSER analysis and that portion of the 2018 Proposal have not been finalized and are being withdrawn in this final action. The 2018 Proposal stated that the Agency was proposing to find that partial CCS is not the BSER on grounds that it is too costly and that the 2015 Rule did not show that the technology had sufficient geographic scope to qualify as the BSER for newly constructed coal-fired EGUs. The EPA instead proposed that the BSER for newly constructed coal-fired EGUs would be the most efficient available steam cycle (*i.e.*, supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with the best operating practices instead of partial CCS. In addition, for newly constructed coal-fired EGUs firing moisture-rich fuels (*i.e.*, lignite), the BSER would also include pre-combustion fuel drying using waste heat from the process. The 2018 Proposal also would have revised the standards of performance for reconstructed EGUs, the maximally stringent standards for coal-fired EGUs undergoing large modifications (*i.e.*, modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent), and for base load and non-base load operating conditions that reflected the Agency's revised BSER determination. The 2018 Proposal did not revise the BSER for any other sources as determined in the 2015 Rule. It also included minor amendments to the applicability criteria for combined heat and power (CHP) and non-fossil EGUs and other miscellaneous technical changes in the regulatory requirements.

2. Withdrawal of the 2018 Proposal

In this action, under CAA section 111(b), the Agency is withdrawing the 2018 Proposal and the proposed determination that the BSER for coal-fired steam generating units should be highly efficient generation technology combined with best operating practices. The EPA no longer believes there is a basis for finding that highly efficient generation technology combined with best operating practices are the BSER for coal-fired steam generating units. As described at length in this preamble, CCS technology is adequately demonstrated for coal-fired steam generating units and so it is not appropriate to impose the less effective emission control of highly efficient generation combined with best operating practices for new sources in this source category. Moreover, the EPA is presently considering whether to revise the 2015 Rule to take into account improvements in CCS technology and the existing tax credits under the IRA. For a more in-depth, technical discussion of the rationale underlying this action, please refer to the technical memorandum in the docket titled, *2018 Proposal Withdrawal*.

B. Additional Amendments

The EPA proposed and is finalizing multiple less significant amendments. These amendments are either strictly editorial and will not change any of the requirements of 40 CFR part 60, subpart TTTT, or will add additional compliance flexibility. The amendments are also incorporated into the final subpart TTTTa. For additional information on these amendments, see the redline strikeout version of the rule showing the amendments in the docket for this action.

First, the EPA proposed and is finalizing editorial amendments to define acronyms the first time they are used in the regulatory text. Second, the EPA proposed and is finalizing adding International System of Units (SI) equivalent for owners/operators of stationary combustion turbines complying with a heat input-based standard. Third, the EPA proposed and is finalizing correcting errors in the current 40 CFR part 60, subpart TTTT, regulatory text referring to part 63 instead of part 60. Fourth, as a practical matter owners/operators of stationary combustion turbines subject to the heat input-based standard of performance need to maintain records of electric sales to demonstrate that they are not subject to the output-based standard of performance. Therefore, the EPA proposed and is finalizing adding a specific requirement that owner/operators maintain records of electric sales to demonstrate they did not sell electricity above the threshold that would trigger the output-based standard. Next, the EPA proposed and is finalizing updating the ANSI, ASME, and ASTM International (ASTM) test methods to include more recent versions of the test methods. Finally, the EPA proposed and is finalizing adding additional compliance flexibilities for EGUs either serving a common electric generator or using a common stack.

C. Eight-year Review of NSPS for Fossil Fuel-Fired Steam Generating Units

1. Modifications

In the 2015 NSPS, the EPA issued final standards for a steam generating

[895] 80 FR 64510 (October 23, 2015).

[896] As part of the interagency review process, an error in the partial CCS costing report that the EPA used to update the costs of partial CCS between the 2018 Proposal and 2020 OMB Review Package was identified. The error included in the original 2020 OMB Review Package had the impact of increasing the cost of partial CCS. The corrected report resulted in partial CCS costs that were similar to those included in the 2018 Proposal.

[897] *State of California* v. *EPA* (D.C. Cir. 21–1035), Document No. 1893155 (April 5, 2021).

unit that implements a ''large modification,'' defined as a physical change, or change in the method of operation, that results in an increase in hourly CO_2 emissions of more than 10 percent when compared to the source's highest hourly emissions in the previous 5 years. Such a modified steam generating unit is required to meet a unit-specific CO_2 emission limit determined by that unit's best demonstrated historical performance (in the years from 2002 to the time of the modification). The 2015 NSPS did not include standards for a steam generating unit that implements a ''small modification,'' defined as a change that results in an increase in hourly CO_2 emissions of less than or equal to 10 percent when compared to the source's highest hourly emissions in the previous 5 years.[898]

In the 2015 NSPS, the EPA explained its basis for promulgating this rule as follows. The EPA has historically been notified of only a limited number of NSPS modifications involving fossil fuel-fired steam generating units and therefore predicted that very few of these units would trigger the modification provisions and be subject to the proposed standards. Given the limited information that we have about past modifications, the Agency has concluded that it lacks sufficient information to establish standards of performance for all types of modifications at steam generating units at this time. Instead, the EPA has determined that it is appropriate to establish standards of performance at this time for larger modifications, such as major facility upgrades involving, for example, the refurbishing or replacement of steam turbines and other equipment upgrades that result in substantial increases in a unit's hourly CO_2 emissions rate. The Agency has determined, based on its review of public comments and other publicly available information, that it has adequate information regarding the types of modifications that could result in large increases in hourly CO_2 emissions, as well as on the types of measures available to control emissions from sources that undergo such modifications, and on the costs and effectiveness of such control measures, upon which to establish standards of performance for modifications with large emissions increases at this time.[899] The EPA did not reopen any aspect of these determinations concerning modifications in the 2015 NSPS, except, as noted below, for the BSER and associated requirements for large modifications.

Because the EPA has not promulgated a NSPS for small modifications, any existing steam generating unit that undertakes a change that increases its hourly CO_2 emissions rate by 10 percent or less will continue to be treated as an existing source that is subject to the CAA section 111(d) requirements being finalized today.

With respect to large modifications, the EPA explained in the 2015 NSPS that they are rare, but there is record evidence indicating that they may occur.[900] Because the EPA is finalizing requirements for existing coal-fired steam generating units that are, on their face, more stringent than the requirements for large modifications, the EPA believes it is appropriate to review and revise the latter requirements to minimize the anomalous incentive that an existing source could have to undertake a large modification for the purpose of avoiding the more stringent requirements that it would be subject to if it remained an existing source. Accordingly, the EPA proposed and is finalizing amending the BSER for large modifications for coal-fired steam generating units to mirror the BSER for the subcategory of long-term coal-fired steam generating units that is, the use of CCS with 90 percent capture of CO_2. The EPA believes that it is reasonable to assume that any existing source that invests in a physical change or change in the method of operation that would qualify as a large modification expects to continue to operate past 2039. Accordingly, the EPA has determined that CCS with 90 percent capture qualifies as the BSER for such a source for the same reasons that it qualifies as the BSER for existing sources that plan to operate past December 31, 2039. The EPA discusses these reasons in section VII.C.1.a of this preamble. The EPA has determined that CCS with 90 percent capture qualifies as the BSER for large modifications, and not the controls determined to be the BSER in the 2015 NSPS, due to the recent reductions in the cost of CCS.

By the same token, the EPA is finalizing that the degree of emission limitation associated with CCS with 90 percent capture is an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis), the same as finalized for existing sources with CCS with 90 percent capture. See section VII.C.3.a of this preamble. Based on this degree of emission limitation, the EPA proposed and is finalizing that the standard of performance for steam generating units that undertake large modifications after May 23, 2023, is a unit-specific emission limit determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification). The EPA proposed and is finalizing that an owner/operator of a modified steam generating unit comply with the emissions rate upon startup of the modified affected facility or the effective date of the final rule, whichever is later. The EPA proposed and is finalizing the same testing, monitoring, and reporting requirements as are currently in 40 CFR part 60, subpart TTTT.

The EPA did not propose, and is not finalizing, any review or revision of the 2015 standard for large modifications of oil- or gas-fired steam generating units because the we are not aware of any existing oil- or gas-fired steam generating EGUs that have undertaken such modifications or have plans to do so, and, unlike an existing coal-fired steam generating EGUs, existing oil- or gas-fired steam units have no incentive to undertake such a modification to avoid the requirements we are including in this final rule for existing oil- or gas-fired steam generating units.

2. New Construction and Reconstruction

The EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015. In the proposal, the EPA proposed that it did not need to review the 2015 NSPS because at that time, the EPA did not have information indicating that any such units will be constructed or reconstructed. However, the EPA has recently become aware that a new coal-fired power plant is under consideration in Alaska. In November 2023, DOE announced a $9 million cooperative agreement for the Alaska Railbelt Carbon Capture and Storage (ARCCS) project, to be led by researchers at the University of Alaska Fairbanks. The ARCCS project would study the viability of a carbon storage complex in Southcentral Alaska, likely at the mostly-depleted Beluga River gas field west of Anchorage'' in the Cook Inlet Basin, which could store captured CO_2. According to reports, the privately owned Flatlands Energy Corp. is considering constructing a 400 MW coal- and biomass-fired power plant in the Susitna River valley region, which, if built, would be one of the sources of captured CO_2.[901]

[898] 80 FR 64514 (October 23, 2015).

[899] *Id.* at 64597–98.

[900] *Id.* at 64598.

[901] DOE Funding Opportunity Announcement, ''DOE Invests More Than $444 Million for CarbonSAFE Project,'' (November 15, 2023), *https://netl.doe.gov/node/13090*; University of Alaska

In light of this development, the EPA is not finalizing its proposal not to review the 2015 NSPS. Instead, the EPA will continue to consider whether to review the 2015 NSPS and will monitor the development of this potential new construction project in Alaska as well as any other potential projects to newly construct or reconstruct a coal-fired power plant. If the EPA does decide to review the 2015 NSPS, it would propose to revise them for coal-fired steam generating units.

D. Projects Under Development

During the 2015 NSPS rulemaking, the EPA identified the Plant Washington project in Georgia and the Holcomb 2 project in Kansas as EGU "projects under development" based on representations by developers that the projects had commenced construction prior to the proposal of the 2015 NSPS and, thus, would not be new sources subject to the final NSPS (80 FR 64542–43; October 23, 2015). The EPA did not set a performance standard at the time but committed to doing so if new information about the projects became available. These projects were never constructed and are no longer expected to be constructed.

The Plant Washington project was to be an 850 MW supercritical coal-fired EGU. The Environmental Protection Division (EPD) of the Georgia Department of Natural Resources issued air and water permits for the project in 2010 and issued amended permits in 2014.[902 903 904] In 2016, developers filed a request with the EPD to extend the construction commencement deadline specified in the amended permit, but the director of the EPD denied the request, effectively canceling the approval of the construction permit and revoking the plant's amended air quality permit.[905]

The Holcomb 2 project was intended to be a single 895 MW coal-fired EGU and received permits in 2009 (after earlier proposals sought approval for development of more than one unit). In 2020, after developers announced they would no longer pursue the Holcomb 2 expansion project, the air permits were allowed to expire, effectively canceling the project.

For these reasons, the EPA proposed and is finalizing a decision to remove these projects under the applicability exclusions in subpart TTTT.

X. State Plans for Emission Guidelines for Existing Fossil Fuel-Fired EGUs

A. Overview

This section provides information related to state plan development, including methodologies for establishing presumptively approvable standards of performance for affected EGUs, flexibilities for complying with standards of performance, and components that must be included in state plans as well as the process for submission. This section also addresses significant comments on and any changes to the proposed emission guidelines regarding state plans that the EPA is finalizing in this action.

State plan submissions under these emission guidelines are governed by the requirements of 40 CFR part 60, subpart Ba (subpart Ba).[906] The EPA finalized revisions to certain aspects of 40 CFR part 60, subpart Ba, in November 2023, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* (final subpart Ba).[907] Unless expressly amended or superseded in these emission guidelines, the provisions of subpart Ba apply. This section explicitly addresses any instances where the EPA is adding to, superseding, or otherwise varying the requirements of subpart Ba for the purposes of these particular emission guidelines.

As noted in the preamble of the proposed action, under the Tribal Authority Rule (TAR) adopted by the EPA, Tribes may seek authority to implement a plan under CAA section 111(d) in a manner similar to that of a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to that of a state for purposes of developing a Tribal Implementation Plan (TIP) implementing the emission guidelines. If a Tribe obtains approval and submits a TIP, the EPA will generally use similar criteria and follow similar procedures as those described for state plans when evaluating the TIP submission and will approve the TIP if appropriate. The EPA is committed to working with eligible Tribes to help them seek authorization and develop plans if they choose. Tribes that choose to develop plans will generally have the same flexibilities available to states in this process.

In section X.B of this document, the EPA describes the foundational requirement that state plans achieve an equivalent level of emission reduction to the degree of emission limitation achievable through application of the BSER as determined by the EPA. Section X.C describes the presumptive methodology for calculating the standards of performance for affected EGUs based on subcategory assignment, as well as requirements related to invoking RULOF to apply a less stringent standard of performance than results from the EPA's presumptive methodology. Section X.C also describes requirements for increments of progress for affected EGUs in certain subcategories and for establishing milestones and reporting obligations for affected EGUs that plan to permanently cease operations, as well as testing and monitoring requirements. In section X.D, the EPA describes how states are permitted to include flexibilities such as emission trading and averaging as compliance measures for affected EGUs in their state plans. Finally, section X.E describes what must be included in state plans, including plan components specific to these emission guidelines and requirements for conducting meaningful engagement, as well as the timing of state plan submission and EPA review of state plans and plan revisions.

In this section of the preamble, the term "affected EGU" means any existing fossil fuel-fired steam generating unit that meets the applicability criteria described in section VII.B of this preamble. Affected EGUs are covered by the emission guidelines being finalized in this action under 40 CFR part 60 subpart UUUUb.

Fairbanks, Institute of Northern Engineering, "Cook Inlet Region Low Carbon Power Generation With Carbon Capture, Transport, and Storage Feasibility Study," *https://ine.uaf.edu/media/391133/cook-inlet-low-carbon-power-feasibility-study-uaf-pcorfinal.pdf*; Herz, Nathaniel, "Could a new Alaska coal power plant be climate friendly? An $11 million study aims to find out," Northern Journal (December 29, 2923), republished in Anchorage Daily News, *https://www.adn.com/business-economy/energy/2023/12/29/could-a-new-alaska-coal-power-plant-be-climate-friendly-an-11-million-study-aims-to-find-out/*.

[902] *https://www.gpb.org/news/2010/07/26/judge-rejects-coal-plant-permits*.

[903] *https://www.southernenvironment.org/press-release/court-rules-ga-failed-to-set-safe-limits-on-pollutants-from-coal-plant/*.

[904] *https://permitsearch.gaepd.org/permit.aspx?id=PDF-OP-22139*.

[905] *https://www.southernenvironment.org/wp-content/uploads/legacy/words_docs/EPD_Plant_Washington_Denial_Letter.pdf*.

[906] 40 CFR 60.20a–60.29a.

[907] 88 FR 80480 (November 17, 2023). At the time of promulgation of these emission guidelines, the November 2023 updates to the CAA section 111(d) implementing regulations are subject to litigation in the D.C. Circuit Court of Appeals. *West Virginia* v. *EPA*, D.C. Circuit No. 24–1009. The outcome of that litigation will not affect any of the distinct requirements being finalized in these emission guidelines, which are not directly dependent on those procedural requirements. Moreover, regardless of the outcome of that litigation, the necessary regulatory framework will exist for states to develop and submit state plans that include standards of performance for affected EGUs pursuant to these emission guidelines and prior implementing regulations.

B. Requirement for State Plans To Maintain Stringency of the EPA's BSER Determination

As explained in section V.C of this preamble, CAA section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include standards of performance for existing sources. Under CAA section 111(a)(1), 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 . . . the Administrator determines has been adequately demonstrated." That is, the EPA has the responsibility to determine the BSER for a given category or subcategory of sources and to determine the degree of emission limitation achievable through application of the BSER to affected sources.[908] The level of emission reductions required of existing sources under CAA section 111 is reflected in the EPA's presumptive standards of performance,[909] which achieve emission reductions under these emission guidelines through requiring cleaner performance by affected sources.

States use the EPA's presumptive standards of performance to establish requirements for affected sources in their state plans. In general, the standards of performance that states establish for affected sources must be no less stringent than the presumptive standards of performance in the applicable emission guidelines.[910] Thus, in order for the EPA to find a state plan "satisfactory," that plan must address each affected EGU within the state and must achieve at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance, after accounting for any application of RULOF.[911] That is, while states have the discretion to establish the applicable standards of performance for affected EGUs in their state plans, the structure and purpose of CAA section 111 and the EPA's regulations require that those plans achieve an equivalent level of emission reductions as applying the EPA's presumptive standards of performance to each of those sources (again, after accounting for any application of RULOF). Section X.C of this preamble addresses how states maintain the level of emission reduction when establishing standards of performance, and section X.D of this preamble addresses how states maintain the level of emission reduction when incorporating compliance flexibilities.

Additionally, consistent with the understanding that the purpose of CAA section 111 is for affected sources to reduce their emissions through cleaner operation, the Agency is also clarifying that emissions reductions from sources *not* affected by the final emission guidelines may not be counted towards compliance with either a source-specific or aggregate standard of performance. In other words, state plans may not account for emission reductions at non-affected fossil fuel-fired EGUs, emission reductions due to the operation or installation of other electricity-generating resources not subject to these emission guidelines for the purposes of demonstrating compliance with affected EGUs' standards of performance.

C. Establishing Standards of Performance

This section addresses several topics related to standards of performance in state plans. First, this section describes affected EGUs' eligibility for the subcategories in the final emission guidelines and how to calculate presumptive standards of performance, including calculating unit-specific baseline emission performance. Second, it summarizes compliance date information as well as how states can provide for a compliance date extension mechanism in their state plans. Third, this section describes how states may consider RULOF to apply a less stringent standard of performance or a longer compliance schedule to a particular affected EGU. Fourth, it explains how states must establish certain increments of progress for affected EGUs installing control technology to comply with standards of performance, as well as milestones and reporting obligations for affected EGUs demonstrating that they plan to permanently cease operations. And, finally, this section describes emission testing and monitoring requirements.

Affected EGUs that meet the applicability requirements discussed in section VII.B must be addressed in the state plan. For each affected EGU within the state, the state plan must include a standard of performance and compliance schedule. That is, each individual unit must have its own, source-specific standard of performance and compliance schedule. Coal-fired affected EGUs must have increments of progress in the state plan and, if they plan to permanently cease operation and to rely on such cessation of operation for purposes of these emission guidelines, an enforceable commitment and reporting obligations and milestones. State plans must also specify the test methods and procedure for determining compliance with the standards of performance.

While a presumptive methodology for standards of performance and other requirements were proposed for existing combustion turbine EGUs, the EPA is not finalizing emission guidelines for such EGUs at this time; therefore, the following discussion will not address the proposed combustion turbine EGU requirements or comments pertaining to these proposed requirements. In addition, the EPA is not finalizing the imminent- and near-term coal-fired subcategories for coal-fired steam generating units; therefore, the following discussion will not address these proposed subcategories or comments pertaining to these proposed subcategories. Similarly, the EPA is not finalizing emission guidelines for states and territories in non-contiguous areas, and is therefore not finalizing the proposed subcategories for non-continental oil-fired steam generating units or associated requirements nor addressing comments pertaining to these subcategories in this section.

1. Application of Presumptive Standards

This section of the preamble describes the EPA's approach to providing presumptive standards of performance for each of the subcategories of affected EGUs under these emission guidelines, including establishing baseline emission performance. As explained in section X.B of this preamble, CAA section 111(a)(1) requires that standards of performance reflect the degree of emission limitation achievable through application of the BSER, as determined by the EPA. For each subcategory of affected EGUs, the EPA has determined a BSER and degree of emission limitation and is providing, in these emission guidelines, a methodology for

[908] *See, e.g., West Virginia* v. *EPA,* 597 U.S. 697, 720 (2022) ("In devising emissions limits for power plants, EPA first 'determines' the 'best system of emission reduction' that—taking into account cost, health, and other factors—it finds 'has been adequately demonstrated.' The Agency then quantifies 'the degree of emission limitation achievable' if that best system were applied to the covered source.") (internal citations omitted).

[909] See 40 CFR 60.22a(b)(5).

[910] 40 CFR 60.24a(c).

[911] As explained in section X.C.2 of this preamble, states may invoke RULOF to apply a less stringent standard of performance to a particular affected EGU when the state demonstrates that the EGU cannot reasonably achieve the degree of emission limitation determined by the EPA. In this case, the state plan may not necessarily achieve the same stringency as each source achieving the EPA's presumptive standards of performance because affected EGUs for which RULOF has been invoked would have standards of performance less stringent than the EPA's presumptive standards.

establishing presumptively approvable standards of performance (also referred to as "presumptive standards of performance" or "presumptive standards"). Appropriate use of these methodologies will result in standards of performance that achieve the requisite degree of emission limitation and therefore meet the statutory requirements of section 111(a)(1) and the corresponding regulatory requirement that standards of performance must generally be no less stringent that the corresponding emission guidelines.[912] 40 CFR 60.24a(c).

Thus, a state, when establishing standards of performance for affected EGUs in its plan, must identify each affected EGU in the state and specify into which subcategory each affected EGU falls. The state would then use the corresponding methodology for the given subcategory to establish the presumptively approvable standard of performance for each affected EGU.

As discussed in section X.C.2 of this preamble, states may apply less stringent standards of performance to particular affected EGUs in certain circumstances based on consideration of RULOF. States also have the authority to deviate from the methodology provided in these emission guidelines for presumptively approvable standards in order to apply a more stringent standard of performance (*e.g.*, a state decides that an affected EGU in the medium-term coal-fired subcategory should comply with a standard of performance corresponding to co-firing 50 percent natural gas instead of 40 percent). Application of a standard of performance that is more stringent than provided by the EPA's presumptive methodology does not require application of the RULOF provisions.[913]

a. Establishing Baseline Emission Performance for Presumptive Standards

For each subcategory, the methodology to calculate a standard of performance entails establishing a baseline of CO_2 emissions and corresponding electricity generation or heat input for an affected EGU and then applying the degree of emission limitation achievable through the application of the BSER (as established in section VII.C of this preamble). The methodology for establishing baseline emission performance for an affected EGU will result in a value that is unique to each affected EGU. To establish baseline emission performance for an affected EGU in all the subcategories except the low load natural gas- and oil-fired subcategories, the EPA is finalizing a determination that a state will use the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**. For affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, the EPA is finalizing a determination that a state will use the CO_2 mass emissions and corresponding heat input for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**. This period is based on the NSR program's definition of "baseline actual emissions" for existing electric steam generating units. See 40 CFR 52.21(b)(48)(i). Eight quarters of 40 CFR part 75 data corresponds to a 2-year period, but the EPA is finalizing this continuous 8-quarter period as it corresponds to quarterly reporting according to 40 CFR part 75. Functionally, the EPA expects states to utilize the most representative continuous 8-quarter period of data from the 5-year period immediately preceding the date the final rule is published in the **Federal Register**. For the 8 quarters of data, a state would divide the total CO_2 emissions (in the form of pounds) over that continuous time period by either the total gross electricity generation (in the form of MWh) or, for affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, the total heat input (in the form of MMBtu) over that same time period to calculate baseline CO_2 emission performance in either lb of CO_2 per MWh or lb of CO_2 per MMBtu. As an example, a state establishing baseline emission performance for an affected EGU in the medium-term coal-fired subcategory in the year 2023 would start by evaluating the CO_2 emissions and electricity generation data for the affected EGU for 2018 through 2022 and choose a continuous 8-quarter period that it deems to be the most appropriate representation of the operation of that affected EGU. While the EPA will evaluate the choice of baseline periods chosen by states when reviewing state plan submissions, the EPA intends to defer to a state's reasonable exercise of discretion as to which 8-quarter period is representative.

The EPA is finalizing the use of 8 quarters during the 5-year period prior to the date the final rule is published in the **Federal Register** as the relevant period for the baseline methodology for several reasons. First, each affected EGU has unique operational characteristics that affect the emission performance of the EGU (load, geographic location, hours of operation, coal rank, unit size, *etc.*), and the EPA believes each affected EGU's emission performance baseline should be representative of the source-specific conditions of the affected EGU and how it has typically operated. Additionally, allowing a state to choose (likely in consultation with the owners or operators of affected EGUs) the 8-quarter period for assessing baseline performance can avoid situations in which a prolonged period of atypical operating conditions would otherwise skew the emissions baseline. Relatedly, the EPA believes that, by using total mass CO_2 emissions and total electric generation or heat input for an affected EGU over an 8-quarter period, any relatively short-term variability of data due to seasonal operations or periods of startup and shutdown, or other anomalous conditions, will be averaged into the calculated level of baseline emission performance. The baseline-setting approach also aligns with the reporting and compliance requirements in the final emission guidelines. Using total mass CO_2 emissions and total electric generation or heat input provides a simple and streamlined approach for calculating baseline emission performance without the need to sort and filter non-representative data; any minor amount of non-representative data will be subsumed and accounted for through implicit averaging over the course of the 8-quarter period. Moreover, by not sorting or filtering the data, this approach reduces the need for discretion in assessing whether the data is appropriate to use. Commenters generally supported the proposed methodology for setting a baseline, particularly saying that they prefer not to have to sort or filter any data.

The EPA believes that using this baseline-setting approach as the basis for establishing presumptively approvable standards of performance will provide certainty for states, as well as transparency and a streamlined process for state plan development. While this approach is specifically designed to be flexible enough to

[912] Should a state decide to establish a standard of performance for an affected EGU using a methodology other than that provided by the EPA in these emission guidelines, the state would have to demonstrate that the resulting standard of performance achieves equivalent emission reductions as application of the EPA's presumptive standard of performance.

[913] 88 FR 80529–31 (November 17, 2023).

accommodate unit-specific circumstances, states retain the ability to deviate from this methodology. The EPA believes that the instances in which a state may need to use an alternate baseline-setting methodology will be limited to anticipated changes in operation, (*i.e.*, circumstances in which historical emission performance is not representative of future emission performance). States that wish to vary the baseline calculation for an affected EGU based on anticipated changes in operation of that EGU, when those changes result in a less stringent standard of performance, must use the RULOF mechanism, which is designed to address such contingencies.

Comment: Commenters sought clarification as to whether the methodology referred to the previous 5 calendar years or the 5-year period ending on the most recent quarter reported under 40 CFR part 75 prior to publication of the final emission guidelines.

Response: The EPA clarifies that the methodology refers to the 5-year period ending on the most recent quarter reported under 40 CFR part 75 prior to publication of the final emission guidelines in the **Federal Register**.

b. Presumptive Standards for Fossil Fuel-Fired Steam Generating Units

As described in section VII of this preamble, the EPA is finalizing separate subcategories of existing fossil fuel-fired steam generating units based on fuel type (*i.e.*, coal-fired, natural gas-fired, or oil-fired). Fuel type is based on the status of the source on January 1, 2030, and annual fuel use reporting is required after that date as a part of compliance. The EPA is further creating a subcategory for coal-fired steam generating units operating in the medium term, and further subcategorizing natural gas- and oil-fired steam generating units by load level.

Consistent with CAA section 111(d)(1)'s requirement that state plans provide for the implementation and enforcement of standards of performance, for affected EGUs in the medium-term subcategory, states must include sources' enforceable commitments to cease operating before January 1, 2039, in their plans. The state plan must specify the calendar date by which the affected EGU plans to cease operation; to be included in a state plan, a commitment to cease operations by such a date must be enforceable by the state, whether through state rule, agreed order, permit, or other legal instrument.[914] Upon EPA approval of the state plan, that commitment will become federally- and citizen-enforceable.

For affected oil- and natural gas-fired steam generating units, subcategories are defined by load level and the type of fuel fired. There are three subcategories for natural gas- and oil-fired steam generating units (base load, intermediate load, and low load). Because subcategory applicability is determined retrospectively, as opposed to prospectively, and because the standards of performance for oil- and natural gas-fired affected EGUs are based on BSERs that do not require add-on controls, it is not necessary to require these sources to take enforceable utilization commitments limiting them to just one subcategory in order to implement and enforce their standards. For steam generating units that meet the definition of natural gas- or oil-fired, and that either retain the capability to fire coal after the date this final rule is published in the **Federal Register**, that fired any coal during the 5-year period prior to that date, or that will fire any coal after that date and before January 1, 2030, the plan must include a requirement to remove the capability to fire coal before January 1, 2030.

The EPA is finalizing a requirement that compliance be demonstrated annually. For affected EGUs in all subcategories except the low load natural gas- and oil-fired subcategory, an affected EGU must demonstrate compliance based on the lb CO_2/MWh emission rate derived by dividing the total reported CO_2 mass emissions by the total reported electric generation during the compliance period (corresponding to 1 calendar year), which is consistent with the expression of the degree of emission limitation for each subcategory in sections VII.C.3 and VII.D.3. For affected EGUs in the low load natural gas- and oil-fired subcategory, an affected EGU must demonstrate compliance based on the lb CO_2/MMBtu emission rate derived by dividing the total reported CO_2 mass emissions by the total reported heat input during the compliance period (again, corresponding to 1 calendar year), consistent with the expression of the degree of emission limitation for the subcategory in section VII.D.3.[915] In other words, for units with a compliance date of January 1, 2030, the first compliance period will be January 1, 2030, through December 31, 2030. For units with a compliance date of January 1, 2032, the first compliance period will be January 1, 2032, through December 31, 2032. The compliance demonstration must occur by March 1 of the following year (*i.e.*, for the 2030 compliance period, by March 1, 2031).

In addition, the EPA is finalizing a requirement that standards of performance must be established as either a rate or, for affected EGUs in certain subcategories, a mass of emissions. If a state chooses to allow mass-based compliance for certain affected EGUs it must first calculate the rate-based emission limitation that corresponds to the presumptive standard of performance, and then explain how it translated that rate-based emission limitation into the mass that constitutes an affected EGU's standard of performance. See section X.D of this preamble for more information on demonstrating compliance where states are incorporating compliance flexibilities.

i. Long-Term Coal-Fired Steam Generating Units

This section describes the EPA's methodology for establishing presumptively approvable standards of performance for long-term coal-fired steam generating units. Affected coal-fired steam generating units that do not meet the specifications of the medium-term coal-fired EGU subcategory are necessarily long-term units, and have a BSER of CCS with 90 percent capture and a degree of emission limitation of 90 percent capture of the mass of CO_2 in the flue gas (*i.e.*, the mass of CO_2 after the boiler but before the capture equipment) over an extended period of time and an 88.4 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*i.e.*, an annual calendar-year basis). The EPA is finalizing a determination that where states use the methodology described here to establish standards of performance for affected EGUs in this subcategory, those established standards will be presumptively approvable when included in a state plan submission.

Establishing a standard of performance for an affected coal-fired EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described in section X.C.1.a of this preamble); and applying the degree of emission limitation, based on the application of the BSER, to that level of baseline emission performance. Implementation of CCS with a capture rate of 90 precent translates to a degree

[914] 40 CFR 60.26a.

[915] If the state plan incorporates compliance flexibilities like emission averaging and trading, an affected EGU must demonstrate compliance consistent with the expression of the respective flexibility. See section X.D of this preamble for more information.

of emission limitation comprising of an 88.4 percent reduction in CO_2 emission rate compared to the baseline level of emission performance. Using the complement of 88.4 percent (*i.e.,* 11.6 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance. For example, if a long-term coal-fired EGU's level of baseline emission performance is 2,000 lbs CO_2 per MWh, it will have a presumptively approvable standard of performance of 232 lbs CO_2 per MWh (2,000 lbs CO_2 per MWh multiplied by 0.116).

The EPA is also finalizing a requirement that affected coal-fired EGUs in the long-term subcategory comply with federally enforceable increments of progress, which are described in section X.C.3 of this preamble.

ii. Medium-Term Coal-Fired Steam Generating Units

This section describes the EPA's methodology for establishing presumptively approvable standards of performance for medium-term coal-fired steam generating units. Affected coal-fired steam generating units that plan to commit to permanently cease operations before January 1, 2039, have a BSER of 40 percent natural gas co-firing on a heat input basis. The EPA is finalizing a determination that where states use the methodology described here to establish standards of performance for an affected EGU in this subcategory, those established standards of performance would be presumptively approvable when included in a state plan submission.

Establishing a standard of performance for an affected EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described in section X.C.1.a); and applying the degree of emission limitation, based on the application of the BSER, to that level of baseline emission performance. Implementation of natural gas co-firing at a level of 40 percent of total annual heat input translates to a level of stringency of a 16 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*i.e.,* an annual calendar-year basis) compared to the baseline level of emission performance. Using the complement of 16 percent (*i.e.,* 84 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance for the affected EGU. For example, if a medium-term coal-fired EGU's level of baseline emission performance is 2,000 lbs CO_2 per MWh, it will have a presumptively approvable standard of performance of 1,680 CO_2 lbs per MWh (2,000 lbs CO_2 per MWh multiplied by 0.84).

For medium-term coal-fired steam generating units that have an amount of co-firing that is reflected in the baseline operation, the EPA is finalizing a requirement that states account for such preexisting co-firing in adjusting the degree of emission limitation. If, for example, an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to a 12 percent reduction in CO_2 emission rate on a lb CO_2/MWh-gross basis compared to the baseline level of emission performance (*i.e.,* an additional 30 percent of natural gas by heat input) to reflect the preexisting level of natural gas co-firing. This results in a standard of performance based on the degree of emission limitation achieving an additional 30 percent co-firing beyond the 10 percent that is accounted for in the baseline. The EPA believes this approach is a more straightforward mathematical adjustment than adjusting the baseline to appropriately reflect a preexisting level of co-firing.

The standard of performance for the medium-term coal-fired subcategory is based on the degree of emission limitation that is achievable through application of the BSER to the affected EGUs in the subcategory and consists exclusively of the rate-based emission limitation. However, the BSER determination for this subcategory is predicated on the assumption that affected EGUs within it will permanently cease operations prior to January 1, 2039. If a state decides to place an affected EGU in the medium-term coal-fired subcategory, the state plan must include that EGU's commitment to permanently cease operating as an enforceable requirement. The state plan must also include provisions that provide for the implementation and enforcement of this commitment, including requirements for monitoring, reporting, and recordkeeping.

Affected coal-fired EGUs that are relying on commitments to cease operating must comply with the milestones and reporting requirements as specified under these emission guidelines. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with their state plan requirements and to help ensure that any issues with implementation are identified in a timely and efficient manner. These milestones are described in detail in section X.C.4 of this preamble. Affected EGUs in this subcategory would also be required to comply with the federally enforceable increments of progress described in section X.C.3 of this preamble.

iii. Natural Gas-Fired Steam Generating Units and Oil-Fired Steam Generating Units

This section describes the EPA's final methodology for presumptively approvable standards of performance for the following subcategories of affected natural gas-fired and oil-fired steam generating units: low load natural gas-fired steam generating units, intermediate load natural gas-fired steam generating units, base load natural gas-fired steam generating units, low load oil-fired steam generating units, intermediate load oil-fired steam generating units, and base load oil-fired steam generating units. The final definitions of these subcategories are discussed in section VII.D.1 of this preamble. The final presumptive standards of performance are based on degrees of emission limitation that units are currently achieving, consistent with the proposed BSER of routine methods of operation and maintenance, which amounts to a proposed degree of emission limitation of no increase in emission rate.

For natural gas-fired steam generating units, the EPA proposed fixed presumptive standards of 1,500 lb CO_2/MWh-gross for intermediate load units (solicited comment on values between 1,400 and 1,600 lb/MWh-gross) and 1,300 lb CO_2/MWh-gross for base load units (solicited comment on values between 1,250 and 1,400 lb CO_2/MWh-gross). For oil-fired steam generating units, the EPA proposed fixed presumptive standards of 1,500 lb CO_2/MWh-gross for intermediate load units (solicited comment on values between 1,400 and 2,000 lb/MWh-gross) and 1,300 lb CO_2/MWh-gross for base load units (solicited comment on values between 1,250 and 1,800 lb CO_2/MWh-gross).

The EPA is finalizing presumptive standards of performance for affected natural gas-fired and oil-fired steam generating units in lieu of methodologies that states would use to establish presumptive standards of performance. This is largely because of the low variability in emissions data at intermediate and base load for these units and relatively consistent performance between these units at those load levels, as discussed in section VII.D of this preamble and detailed in the final TSD, *Natural Gas- and Oil-fired Steam Generating Units*, which supports the establishment of a generally applicable standard of performance.

For intermediate load natural gas-fired units (annual capacity factors greater than or equal to 8 percent and less than 45 percent), annual emission rates are less than 1,600 lb CO_2/MWh-gross for more than 95 percent of units. Therefore, the EPA is finalizing the presumptive standard of performance of an annual calendar-year emission rate of 1,600 lb CO_2/MWh-gross for these units.

For base load natural gas-fired units (annual capacity factors greater than or equal to 45 percent), annual emission rates are less than 1,400 lb CO_2/MWh-gross for more than 95 percent of units. Therefore, the EPA is finalizing the presumptive standard of performance of an annual calendar-year emission rate of 1,400 lb CO_2/MWh-gross for these units.

In the continental U.S., there are few if any oil-fired steam generating units that operate with intermediate or high utilization. Liquid-oil-fired steam generating units with 24-month capacity factors less than 8 percent do qualify for a work practice standard in lieu of emission requirements under the MATS (40 CFR part 63, subpart UUUUU). If oil-fired units operated at higher annual capacity factors, it is likely they would do so with substantial amounts of natural gas-firing and have emission rates that are similar to steam generating units that fire only natural gas at those levels of utilization. There are a few natural gas-fired steam generating units that are near the threshold for qualifying as oil-fired units (*i.e.*, firing more than 15 percent oil in a given year) but that on average fire more than 90 percent of their heat input from natural gas. Therefore, the EPA is finalizing the same presumptive standards of performance for oil-fired steam generating units as for natural gas-fired units (1,400 lb CO_2/MWh-gross for base load units and 1,600 lb CO_2/MWh-gross for intermediate load units).

Lastly, the EPA is finalizing uniform fuels as the BSER for low load natural gas and oil-fired steam generating units. The EPA is finalizing degrees of emission limitation defined by 130 lb CO_2/MMBtu for low load natural gas-fired steam generating units and 170 lb CO_2/MMBtu for low load oil-fired steam generating units, and presumptively approvable standards consistent with those values.

Comment: One commenter stated that the EPA should instead allow states to define standards using a source's baseline emission rate, with some additional flexibilities to account for changes in load.[916] The commenter also requested that, if the EPA were to finalize presumptive standards, then the higher values that the EPA solicited comment on for natural gas-fired units should be finalized. The commenter similarly requested that, if the EPA were to finalize presumptive standards, then the higher values that the EPA solicited comment on for oil-fired units should be finalized—however, the commenter also noted that its two sources that are currently oil-firing operate below an 8 percent annual capacity factor and would therefore not be subject to the intermediate load or base load presumptive standard.

Response: The EPA is finalizing presumptive standards for natural gas-fired steam generating units of 1,400 lb CO_2/MWh-gross for base load units and 1,600 lb CO_2/MWh-gross for intermediate load units. The EPA is finalizing the same standards for oil-fired steam generating units for the reasons discussed in the preceding text. Few, if any, oil-fired units operate as intermediate load or base load units, as acknowledged by the commenter. Those oil-fired units that have operated near the threshold for intermediate load have typically fired a large proportion of natural gas and operated at emission rates consistent with the final presumptive standards.

c. Compliance Dates

This section summarizes information on the compliance dates, or the first date on which the standard of performance applies, that the EPA is finalizing for each subcategory. As discussed in section X.C.1.b, compliance is required to be demonstrated on an annual (*i.e.*, calendar year) basis.

The EPA proposed a compliance date of January 1, 2030, for all affected steam generating units. As discussed in section VII.C.1.a.i(E) of this preamble, the EPA received comments that this compliance date was not achievable for sources in the long-term coal-fired EGU subcategory that would be installing CCS. In response to those comments, the EPA reevaluated the information and timeline for CCS installation and is finalizing a compliance date of January 1, 2032, for the long-term coal-fired subcategory. The Agency is finalizing a compliance date of January 1, 2030, for units in the medium-term coal-fired subcategory as well as for natural gas- and oil-fired steaming generating units.

[916] See Document ID No. EPA–HQ–OAR–2023–0072–0806.

The EPA refers to January 1, 2030, and January 1, 2032, as "compliance dates," "final compliance dates," and "initial compliance dates" in various parts of this preamble. In each case, the EPA means that this is the date on which affected EGUs must start monitoring and reporting their emissions and other relevant data for purposes of demonstrating compliance with their standards of performance under these emission guidelines. Affected EGUs demonstrate compliance on a calendar year basis, *i.e.*, the compliance period for affected EGUs is 1 calendar year. Therefore, affected EGUs will not have to demonstrate that they are achieving their standards of performance on January 1, 2030, or January 1, 2032, as that demonstration is made only at the end of the compliance period, *i.e.*, at the end of the calendar year. But, again, these are the dates on which affected EGUs in the relevant subcategories must start monitoring and reporting for purposes of their future compliance demonstrations with their standards of performance.

d. Compliance Date Extension Mechanism

The EPA is finalizing provisions that allow states to include a mechanism to extend the compliance date for certain affected EGUs in their state plans. This mechanism is only available for situations in which an affected EGU encounters a delay in installation of a control technology that makes it impossible to commence compliance by the date specified in section X.C.1.c of this preamble. The owner or operator must provide documentation of the circumstances that precipitated the delay (or the anticipated delay) and demonstrate that those circumstances were or are entirely beyond the owner or operator's control and that the owner or operator has no ability to remedy the delay. These circumstances may include, but are not limited to, permitting-related delays or delays in delivery or construction of parts necessary for installation or implementation of the control technology.

The EPA received extensive comment requesting a mechanism to extend the compliance date for affected EGUs installing a control technology to address situations in which the owner or operator of the affected EGU encounters a delay outside of their control. Several industry commenters noted the potential for such delays due to, among other reasons, supply chain constraints, permitting processes, and/or environmental assessments as well as delays in deployment of supporting infrastructure like pipelines. These commenters explained that an extension mechanism could provide greater regulatory certainty for owners and operators. In light of this feedback and acknowledgment that there may be circumstances outside of owners/operators' control that impact their ability to meet the compliance dates in these emission guidelines, the EPA believes that it is reasonable to provide a consistent and transparent means of allowing a limited extension of the compliance deadline where an affected EGU has demonstrated such an extension is needed for installation of controls. This mechanism is intended to address delays in implementation—not to provide more time to assess the compliance strategy (*i.e.*, the type of technology or subcategory assignment) for the affected EGU, as some commenters suggested; those decisions are to be made at the time of state plan approval.

The compliance date extension mechanism is consistent with both CAA section 111 and these emission guidelines. Consistent with the statutory purpose of remedying dangerous air pollution, state plans must generally provide for compliance with standards of performance as expeditiously as practicable but no later than specified in the emission guidelines. 40 CFR 60.24a(c). As discussed in sections VII.C.1.a.i.(E) and VII.C.2.b.i(C), the EPA has determined compliance timelines in these emission guidelines consistent with achieving emission reductions as expeditiously as practicable given the time it takes to install the BSER technologies for the respective subcategories. The compliance dates are designed to accommodate the process steps and timeframes that the EPA reasonably anticipates will apply to affected EGUs. This extension mechanism acknowledges that circumstances entirely outside the control of the owners or operators of affected EGUs may extend the timeframe for installation of control technologies beyond what the EPA reasonably expects for the subcategories as a general matter. Thus, so long as this extension mechanism is limited to circumstances that cannot be reasonably controlled or remedied by states or affected EGUs and that make it impossible to achieve compliance by the dates specified in these emission guidelines, its use is consistent with achieving compliance as expeditiously as practicable.

The EPA is establishing parameters, described in this subsection, for the features of this mechanism (*e.g.*, documentation, time limitation). Within these parameters, states should consider state-specific circumstances related to the implementation and enforcement of this mechanism in their state plans. Importantly, in order to provide compliance date extensions that do not require a state plan revision available to affected EGUs, states must include the mechanism in their proposed state plans that are provided for public comment and meaningful engagement (as well as in the final state plan submitted to the EPA), and the circumstances for and consequences of using this mechanism must be clearly spelled out and bounded. States are not required to include this mechanism in their state plans; absent its inclusion, states must submit a state plan revision in order to extend a compliance schedule that has been approved into a plan.

First, state plans must provide that a compliance date extension through this mechanism is available only for affected EGUs that are installing add-on controls. Affected EGUs that intend to comply without installing additional control technologies—including, but not limited to, oil and gas-fired steam generating EGUs—should not experience the types of installation or implementation delays that this mechanism is intended to address. Second, state plan mechanisms must provide that to receive a compliance date extension, the owner or operator of an affected EGU is required to demonstrate to the state air pollution control agency, and provide supporting documentation to establish, the basis for and plans to address the delay. For each affected EGU, this demonstration must include (1) confirmation that the affected EGU has met the relevant increments of progress up to the point of the delay, including any permits obtained and/or contracts entered into for the installation of control technology, (2) documentation, such as invoices or correspondence with permitting authorities, vendors, etc., of the circumstances of the delay and that the delay is due to the action, or lack thereof, of a third party (*e.g.*, supplier or permitting authority), and that the owner or operator of the affected EGU has itself acted consistent with achieving timely compliance (*e.g.*, in applying for permits with all necessary information or contracting in sufficient time to perform in accordance with required schedules), and (3) plans for addressing the circumstances and remedying the delay as expeditiously as practicable, including updated dates for the final increment of progress corresponding to the compliance date as well as any other increments that are outstanding at the time of the demonstration. These requirements for documentation are intended to ensure, *inter alia*, that the owner or operator has made all reasonable efforts to achieve timely compliance and that the circumstances for granting an extension are not speculative but are rather based on delays the affected EGU is currently experiencing or is reasonably certain to experience.

The extended compliance date must be as expeditiously as practicable and the maximum time allowed for this extension is 1 year beyond the compliance date specified for the affected EGU by the state plan. Several commenters suggested that a 1-year extension was appropriate. If the delay is anticipated to be longer than 1 year, states can provide for the use of this mechanism for up to 1 year but should also initiate a state plan revision if necessary to provide an updated compliance date through consideration of RULOF, subject to EPA approval of the plan revision.

The state air pollution control agency is charged with approving or disapproving a compliance date extension request based on its written determination that the affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation. All documentation for the extension request must be submitted by the owner or operator of the affected EGU to the state air pollution control agency no later than 6 months prior to the compliance date provided in these emission guidelines. The owner or operator of the affected EGU must also notify the relevant EPA Regional Administrator of their compliance date extension request at the time of the submission of the request. The owner or operator of the affected EGU must also post their application for the compliance date extension request to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, when they submit the request to the state air pollution control agency. The state air pollution control agency must notify the relevant EPA Regional Administrator of any determination on an extension request and the new compliance date for any affected EGU(s) with an approved extension at the time of the determination on the extension request. The owner or operator of the affected EGU must also post the state's determination on the compliance extension request to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, upon receipt of the determination, and, if the request is approved, update information on the website related to the compliance date and increments of progress dates within 30 days of the receipt of the state's approval.

2. Remaining Useful Life and Other Factors

Under CAA section 111(d), the EPA is required to promulgate regulations under which states submit plans that ''establish[] standards of performance for any existing source'' and ''provide for the implementation and enforcement of such standards of performance.'' While states establish the standards of performance, there is a fundamental obligation under CAA section 111(d) that such standards reflect the degree of emission limitation achievable through the application of the BSER, as determined by the EPA.[917] The EPA identifies this degree of emission limitation as part of its emission guideline. 40 CFR 60.22a(b)(5). Thus, as described in section X.C.2 of this preamble, the EPA is providing methodologies for states to follow in determining and applying presumptively approvable standards of performance to affected EGUs in each of the subcategories covered by these emission guidelines. In general, the standards of performance that states establish for designated facilities must be no less stringent than the presumptively approvable standards of performance specified in these emission guidelines. 40 CFR 60.24a(c).

However, CAA section 111(d)(1) also requires that the EPA's regulations permit the states, in applying a standard of performance to any particular designated facility, to ''take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies.'' The EPA's implementing regulations under 40 CFR 60.24a allow a state to consider a particular designated facility's remaining useful life and other factors (''RULOF'') in applying to that facility a standard of performance that is less stringent than the presumptive level of stringency in the applicable emission guideline, or a compliance schedule that is longer than prescribed by that emission guideline.

In the proposal, the EPA indicated that it had recently proposed, in a separate rulemaking, to clarify the general implementing regulations governing the application of RULOF. The Agency further explained that the revised RULOF regulations, as finalized in that separate rulemaking, would apply to these emission guidelines. The revisions to the implementing regulations' RULOF provisions were finalized in November 2023, with some changes in response to public comments relative to proposal. As provided by 40 CFR 60.20a(a) and (a)(1) and indicated in the proposal, the RULOF provisions in 40 CFR 60.24a, as revised in the November 2023 final rule, will govern the use of RULOF to provide less stringent standards of performance or longer compliance schedules under these emission guidelines. The EPA is not superseding any provision of the RULOF regulations at 40 CFR 60.24a in these emission guidelines.

As explained in the preamble to the final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d),* the EPA has interpreted the RULOF provision of CAA section 111(d)(1) as allowing states to apply a standard of performance that is less stringent than the degree of emission limitation in the applicable emission guideline, or a longer compliance schedule, to a particular facility based on that facility's remaining useful life and other factors. The use of RULOF to deviate from an emission guideline is available only when there are fundamental differences between the circumstances of a particular facility and the information the EPA considered in determining the degree of emission limitation or the compliance schedule, and those fundamental differences make it unreasonable for the facility to achieve the degree of emission limitation or meet the compliance schedule in the emission guideline. This ''fundamentally different'' standard is consistent with the statutory purpose of reducing dangerous air pollution under CAA section 111; the statutory framework under which, to achieve that purpose, the EPA is directed to determine the degree of emission under CAA section 111(a)(1); and the understanding that RULOF is intended as a limited variance from the EPA's determination to address unusual circumstances at particular facilities.[918]

The relevant consideration for states contemplating the use of RULOF to apply a less stringent standard of performance is whether a designated facility can reasonably achieve the degree of emission limitation in the applicable emission guideline, not whether it can implement the system of emission reduction the EPA determined is the BSER. That is, if a designated facility cannot implement the BSER but can reasonably achieve the specified degree of emission limitation using a different system of emission reduction, the state cannot use RULOF to apply a less stringent standard of performance to that facility.

If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular facility cannot reasonably achieve the degree of emission limitation or compliance schedule determined by the EPA in these emission guidelines, the state may then apply a less stringent standard of performance or longer compliance schedule. The process for doing so is laid out in 40 CFR 60.24a(f). Critically, standards of performance and compliance schedules pursuant to RULOF must be no less stringent, or no longer, than is necessary to address the fundamental difference between the information the EPA considered and the particular facility that was the basis for invoking RULOF under 40 CFR 60.24a(e). In determining a less stringent standard of performance, the state must, to the extent necessary, evaluate the systems of emission reduction identified in the emission guidelines using the factors and evaluation metrics the EPA considered in assessing those systems, including technical feasibility, the amount of emission reductions, the cost of achieving such reductions, any non-air quality health and environmental impacts, and energy requirements. States may also consider, as justified, other factors specific to the facility that were the basis for invoking RULOF under 40 CFR 60.24a(e), as well as additional systems of emission reduction.

The RULOF provision at 40 CFR 60.24a(g) states that, where the basis of a less stringent standard of performance is an operating condition within the control of a designated facility, the state plan must include such operating condition as an enforceable requirement. The state plan must also include requirements, such as for monitoring, reporting, and recordkeeping, for the implementation and enforcement of the condition. This is relevant in the case of, for example, less stringent standards of performance that are based on a particular designated facility's remaining useful life or utilization.

Finally, the general implementing regulations provide that states may always adopt and enforce, as part of their state plans, standards of

[917] *West Virginia* v. *EPA,* 597 U.S. 697, 720 (2022) (''In devising emissions limits for power plants, EPA first 'determines' the 'best system of emission reduction' that—taking into account cost, health, and other factors—it finds 'has been adequately demonstrated.' The Agency then quantifies 'the degree of emission limitation achievable' if that best system were applied to the covered source.'') (internal citations omitted).

[918] See, *e.g.,* 88 FR 80512 (November 17, 2023).

performance that are more stringent than the degree of emission limitation determined by the EPA and compliance schedules that require final compliance more quickly than specified in the applicable emission guidelines. 40 CFR 60.24a(i). States do not have to use the RULOF provisions in 40 CFR 60.24a(e)–(h) to apply a more stringent standard of performance or faster compliance schedule.

The EPA notes that there were a number of RULOF provisions proposed as additions to the general implementation regulations in subpart Ba and discussed in the proposed emission guidances that the EPA did not finalize as part of that separate rulemaking. Any proposed RULOF requirements that were not finalized in 40 CFR 60.24a are likewise not being finalized in this action and do not apply as requirements under these emission guidelines. However, two considerations in particular remain relevant to states' development of plans despite not being finalized as requirements: consideration of communities most impacted by and vulnerable to the health and environmental impacts of an affected EGU that is invoking RULOF, and the need to engage in reasoned decision making that is supported by information and a rationale that is included in the state plan.[919]

As explained in the preamble to the November 2023 final rule revising subpart Ba, consideration of health and environmental impacts is inherent in consideration of two factors, the non-air quality health and environmental impacts and amount of emission reduction, that the EPA considers under CAA section 111(a)(1). Therefore, a state considering whether a variance from the EPA's degree of emission limitation is appropriate will necessarily consider the potential impacts and benefits of control to communities impacted by an affected EGU that is potentially receiving a less stringent standard of performance.[920] Additionally, as discussed in section X.E.1.b.i of this preamble, the general implementing regulations for CAA section 111(d) in subpart Ba require states to submit, with their state plans or plan revisions, documentation that they have conducted meaningful engagement with pertinent stakeholders and/or their representative in the plan (or plan revision) development process. 40 CFR 60.23a(i). The application of a less stringent standard of performance or longer compliance schedule pursuant to RULOF can impact the effects a state plan has on pertinent stakeholders, which include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of a state plan or plan revision. See 40 CFR 60.21a(l). Therefore, the potential application of less stringent standards of performance or longer compliance schedule should be part of a state's meaningful engagement on a state plan or plan revision.

Similarly, the EPA emphasized in the preamble to the November 2023 final rule revising subpart Ba that states carry the burden of making any demonstrations in support of less-stringent standards of performance pursuant to RULOF in developing their plans. As a general matter, states always bear the responsibility of reasonably documenting and justifying the standards of performance in their plans. In order to find a standard of performance satisfactory, the EPA must be able to ascertain, based on the information and analysis included in the state plan submission, that the standard meets the statutory and regulatory requirements.[921]

Comment: Multiple commenters expressed support for the EPA's proposed approach to RULOF, including its framework for ensuring that less stringent standards of performance and longer compliance schedules are limited to unique circumstances that reflect fundamental differences from the circumstances that the EPA considered, and that such standards do not undermine the overall effectiveness of the emission guidelines. These commenters also noted that the proposed RULOF approach is consistent with CAA section 111(d). However, other commenters argued that the EPA lacks authority to put restrictions on how states consider RULOF to apply less stringent standards of performance or longer compliance schedules. Some commenters stated that the EPA's framework for the consideration of RULOF runs counter to section 111's framework of cooperative federalism and that the EPA has a limited role of determining BSER for the source category while the statute reserves significant authority for the states to establish and implement standards of performance. One commenter elaborated that the broad discretion given to states to establish standards of performance gives the EPA only a limited role in reviewing states' RULOF demonstrations.

Response: The provisions that will govern states' use of RULOF under these emission guidelines are contained in the part 40, subpart Ba CAA section 111(d) implementing regulations. Following proposal of these emission guidelines, the EPA finalized revisions to the subpart Ba RULOF provisions in a separate rulemaking. Any comments on these generally applicable provisions, including the EPA's authority to promulgate and implement them and consistency with the cooperative federalism framework of CAA section 111(d), are outside the scope of this action. The EPA has, however, considered and responded to comments that concern the application of these generally applicable RULOF provisions under these particular emission guidelines.

Comment: Several commenters spoke to the role of RULOF given the structure of the proposed subcategories for coal-fired steam generating affected EGUs. Some commenters supported the EPA's statement that, given the four proposed subcategories based on affected EGUs' intended operating horizons, the Agency did not anticipate that states would be likely to need to invoke RULOF based on a particular affected EGU's remaining useful life. In contrast, other commenters stated that the EPA was attempting to unlawfully preempt state consideration of RULOF. Some noted that, regardless of the approach to subcategorization, a particular source may still present source-specific considerations that a state may consider relevant when applying a standard of performance. One commenter referred to RULOF as a way for states to "modify" subcategories to address the circumstances of particular affected EGUs.

Response: As explained in section VII.C of this preamble, the structure of the subcategories for coal-fired steam generating affected EGUs under these final emission guidelines differs from the four subcategories that the EPA proposed. The EPA is finalizing just two subcategories for coal-fired EGUs: the long-term subcategory and the medium-term subcategory. Under these circumstances, the justification for the EPA's statement at proposal that it is unlikely that states would need to invoke RULOF based on a coal-fired steam generating affected EGU's remaining useful life no longer applies. Consistent with 40 CFR 60.24a(e) and the Agency's explanation in the proposal, states have the ability to

[919] The other RULOF provisions that the EPA proposed as additions to 40 CFR 60.24a but did not finalize are related to setting imminent and outermost dates for the consideration of remaining useful life and consideration of RULOF to apply more stringent standards of performance. See 88 FR 80480, 80525, 80529 (November 17, 2023).

[920] 88 FR 80528 (November 17, 2023).

[921] See *id.* at 80527.

consider, *inter alia,* a particular source's remaining useful life when applying a standard of performance to that source.[922]

Moreover, the EPA is clarifying that RULOF may be used to particularize the compliance obligations for an affected EGU when a state demonstrates that it is unreasonable for that EGU to achieve the applicable degree of emission limitation or compliance schedule determined by the EPA. Invocation of RULOF does not have the effect of modifying the subcategory structure or creating a new subcategory for a particular affected EGU. That EGU remains in the applicable subcategory. As explained elsewhere in this section of the preamble, the particularized compliance obligations must differ as little as possible from the presumptive standard of performance and compliance schedule for the subcategory into which the affected EGU falls under these emission guidelines.

Comment: One commenter requested that the EPA identify situations in which it is reasonable to deviate from the presumptive standards of performance in the emission guidelines and include presumptively approvable approaches for states to use when invoking RULOF. The commenter noted that this would reduce the regulatory burden on states developing and submitting plans. Another commenter, however, stated that the EPA should not provide any presumptively approvable standard, criteria, or analytic approach for states seeking to use RULOF. This commenter explained that the premise of source-specific variances under RULOF is that they reflect circumstances that are unique to a particular unit and fundamental differences from the general case, and that it would be inappropriate to offer a generic rubric for approving variances separate from the particularized facts of each case.

Response: The EPA is not identifying circumstances in which it would be reasonable to deviate from its determinations or providing presumptively approvable approaches to invoking RULOF in these emission guidelines. For this source category—fossil-fuel fired steam generating EGUs—in particular, the circumstances and characteristics of affected EGUs and the control strategies the EPA has identified as BSER are extremely context- and source-specific. In order to invoke RULOF for a particular affected EGU, a state must demonstrate that it is unreasonable for that EGU to reasonably achieve the applicable degree of emission limitation or compliance schedule. Given the diversity of sizes, ages, locations, process designs, operating conditions, *etc.*, of affected EGUs, it is highly unlikely that the circumstances that result in one affected EGU being unable to reasonably achieve the applicable presumptive standard or compliance schedule would apply to any other affected EGU. Further, the RULOF provisions of subpart Ba provide clarity for and guidance to states as to what constitutes a satisfactory less-stringent standard of performance under these emission guidelines.

While the EPA is not providing presumptively approvable circumstances or analyses for RULOF in these emission guidelines, it is providing information and analysis that states can leverage in making any determinations pursuant to the RULOF provisions. As explained elsewhere in this section of the preamble, the EPA expects that states will be able to particularize the information it is providing in section VII of this preamble and the final Technical Support Documents for the circumstances of any affected EGUs for which they are considering RULOF, thereby decreasing the analytical burdens.

Comment: Several commenters stated that the proposed emission guidelines did not provide adequate time for RULOF analyses.

Response: As noted above, the EPA expects states to leverage the information it is providing in section VII of this preamble and the final Technical Support Documents in conducting any RULOF analyses under these emission guidelines. In particular, the Agency believes states will be able to use the information it is providing on available control technologies for affected EGUs, technical considerations, and costs given different amortization periods and particularize it for the purpose of conducting any analyses pursuant to 40 CFR 60.24a(e) and (f). Additionally, as discussed in section X.C.2.b of this preamble, the regulatory provisions for RULOF under subpart Ba provide a framework for determining less stringent standards of performance that have the practical effect of minimizing states' analytical burdens. Given the EPA's consideration of affected EGU's circumstances and operational characteristics in designing these emission guidelines, the Agency does not anticipate that states will be in the position of conducting numerous RULOF analyses as part of their state planning processes. The EPA therefore believes that states will have sufficient time to consider RULOF and conduct any RULOF analyses under these emission guidelines.

a. Threshold Requirements for Considering RULOF

The general implementing regulations of 40 CFR part 60, subpart Ba, provide that a state may apply a less stringent standard of performance or longer compliance schedule than otherwise required under the applicable emission guidelines based on consideration of a particular source's remaining useful life and other factors. To do so, the state must demonstrate for each designated facility (or class of such facilities) that the facility cannot reasonably achieve the degree of emission limitation determined by the EPA (*i.e.*, the presumptively approvable standard of performance) based on: (1) Unreasonable cost resulting from plant age, location, or basic process design, (2) physical impossibility or technical infeasibility of installing the necessary control equipment, or (3) other factors specific to the facility. In order to determine that one or more of these circumstances has been met, the state must demonstrate that there are fundamental differences between the information specific to a facility (or class of such facilities) and the information the EPA considered in the applicable emission guidelines that make achieving the degree of emission limitation or compliance schedule in those guidelines unreasonable for the facility.

For each subcategory of affected EGUs in these emission guidelines, the EPA determined the degree of emission limitation achievable through application of the BSER by considering information relevant to each of the factors in CAA section 111(a)(1): whether a system of emission reduction is adequately demonstrated for the subcategory, the costs of a system of emission reduction, the non-air quality health and environmental impacts and energy requirements associated with a system of emission reduction, and the extent of emission reductions from a system.[923] As noted above, the relevant consideration for invoking RULOF is whether an affected EGU can reasonably achieve the presumptive standard of

[922] See 88 FR 33383 (invoking RULOF based on a particular coal-fired EGU's remaining useful life "is not prohibited under these emission guidelines").

[923] The EPA also considered expanded use and development of technology in determining the BSER for each subcategory. However, as this consideration is not necessarily relevant at the scale of a particular source for which a less stringent standard of performance is being considered, it is not addressed here.

performance for the applicable subcategory, as opposed to whether it can implement the BSER. In determining the BSER the EPA found that certain costs, impacts, and energy requirements were, on balance, reasonable for affected EGUs; it is therefore reasonable to assume that the same costs, impacts, and energy requirements would be equally reasonable in the context of other systems of reduction, as well. Therefore, the information the EPA considered in relation to each of these factors is the baseline for consideration of RULOF regardless of the system of emission reduction being considered.

The EPA is providing presumptive standards of performance in these emission guidelines in the form of rate-based emission limitations. Thus, the focus for states considering whether a particular affected EGU has met the threshold for a less stringent standard of performance pursuant to RULOF is whether that affected EGU can reasonably achieve the applicable rate-based presumptive standard of performance in these emission guidelines.

Within each of the statutory factors it considered in determining the BSER, the Agency considered information using one or more evaluation metrics. For example, for both the long-term and medium-term coal-fired steam generating EGUs the EPA considered cost in terms of dollars/ton CO_2 reduced and increases in levelized costs expressed as dollars per MWh electricity generation. Under the non-air quality health and environmental impacts and energy requirements factor, the EPA considered non-greenhouse gas emissions and energy requirements in terms of parasitic load and boiler efficiency, in addition to evaluation metrics specific to the systems being evaluated for each subcategory. For the full range of factors, evaluation metrics, and information the EPA considered with regard to the long-term and medium-term coal-fired steam generating EGU subcategories, see section VII.D.1 and VII.D.2 of this preamble.

Although the considerations for invoking RULOF described in 40 CFR 60.24a(e) are broader than just unreasonable cost of control, much of the information the EPA considered in determining the BSER, and therefore many of the circumstances states might consider in determining whether to invoke RULOF, are reflected in the cost consideration. Where possible, states should reflect source-specific considerations in terms of cost, as it is an objective and replicable metric for comparison to both the EPA's information and across affected EGUs and states.[924] For example, consideration of pipeline length needed for a particular affected EGU is best reflected through consideration of the cost of that pipeline. In particular, consideration of the remaining useful life of a particular affected EGU should be considered with regard to its impact on costs. In determining the BSER, the EPA considers costs and specifically annualized costs associated with payment of the total capital investment associated with the BSER. An affected EGU's remaining useful life and associated length of the capital recovery period can have a significant impact on annualized costs. States invoking RULOF based on an affected EGU's remaining useful life should demonstrate that the annualized costs of applying the degree of emission limitation achievable through application of the BSER for a source with a short remaining useful life are fundamentally different from the costs that the EPA found were reasonable. For purposes of determining the annualized costs for an affected EGU with a shorter remaining useful life, the EPA considers the amortization period to begin at the compliance date for the applicable subcategory.

States considering the use of RULOF to provide a less stringent standard of performance for a particular EGU must demonstrate that the information relevant to that EGU is fundamentally different from the information the EPA considered. For example, in determining the degree of emission limitation achievable through the application of co-firing for medium-term coal-fired steam generating EGUs, the EPA found that costs of $71/ton CO_2 reduced and $13/MWh are reasonable. A state seeking to invoke RULOF for an affected coal-fired steam generating EGU based on unreasonable cost of control resulting from plant age, location, or basic process design would therefore, pursuant to 40 CFR 60.24a(e), demonstrate that the costs of achieving the applicable degree of emission limitation for that particular affected EGU are fundamentally different from $71/ton CO_2 reduced and/or $13/MWh.

Any costs that the EPA has determined are reasonable for any BSER for affected EGUs under these emission guidelines would not be an appropriate basis for invoking RULOF. Additionally, costs that are not fundamentally different from costs that the EPA has determined are or could be reasonable for sources would also not be an appropriate basis for invoking RULOF. Thus, costs that are not fundamentally different from, *e.g.*, $18.50/MWh (the cost for installation of wet-FGD on a 300 MW coal-fired steam generating unit, used for cost comparison in section VIII.D.1.a.ii of this preamble) would not be an appropriate basis for invoking RULOF under these emission guidelines. On the other hand, costs that constitute outliers, *e.g.*, that are greater than the 95th percentile of costs on a fleetwide basis (assuming a normal distribution) would likely represent a valid demonstration of a fundamental difference and could be the basis of invoking RULOF.

Importantly, the costs evaluated in BSER determinations are, in general, based on average values across the fleet of steam generating units. Those BSER cost analysis values represent the average of a distribution of costs including costs that are above or below the average representative value. On that basis, implicit in the determination that those average representative values are reasonable is the determination that a significant portion of the unit-specific costs around those average representative values are also reasonable, including some portion of those unit-specific costs that are above but not significantly different than the average representative values. That is, the cost values the EPA considered in determining the BSER should not be considered bright-line upper thresholds between reasonable and unreasonable costs. Moreover, the examples in this discussion are provided merely for illustrative purposes; because each RULOF demonstration must be evaluated based on the facts and circumstances relevant to a particular affected EGU, the EPA is not setting any generally applicable thresholds or providing presumptively approvable approaches for determining what constitutes a fundamental difference in cost or any other consideration under these emission guidelines. The Agency will assess each use of RULOF in a state plan against the applicable regulatory requirements; however, the EPA is providing examples in this preamble in response to comments requesting that it provide further clarity and guidance on what constitutes a satisfactory use of RULOF.

Under 40 CFR 60.24a(e)(1)(iii), states may also consider ''other factors specific to the facility.'' Such ''other factors'' may include both factors (categories of information) that the EPA did not consider in determining the degree of emission limitation achievable through

[924] The EPA reiterates that states are not precluded from considering information and factors other than costs under 40 CFR 60.24a(e)(ii) and (iii).

application of the BSER and additional evaluation metrics (ways of considering a category of information) that the EPA did not consider in its analysis. To invoke RULOF based on consideration of ''other factors,'' a state must demonstrate that a factor makes it unreasonable for the affected EGU to achieve the applicable degree of emission limitation in these emission guidelines.

The general implementing regulations of subpart Ba provide that states may invoke RULOF for a class of facilities. In the preamble to the subpart Ba final rule, the EPA explained that ''invoking RULOF and providing a less-stringent standard [of] performance or longer compliance schedule for a class of facilities is only appropriate where all the facilities in that class are similarly situated in all meaningful ways. That is, they must not only share the circumstance that is the basis for invoking RULOF, they must also share all other characteristics that are relevant to determining whether they can reasonably achieve the degree of emission limitation determined by the EPA in the applicable EG. For example, it would not be reasonable to create a class of facilities for the purpose of RULOF on the basis that the facilities do not have space to install the EPA's BSER control technology if some of them are able to install a different control technology to achieve the degree of emission limitation in the EG.'' [925] Given that individual fossil fuel-fired steam generating EGUs are very unlikely to be similarly situated with regard to all of the characteristics relevant to determining the reasonableness of meeting a degree of emission limitation, the EPA believes it would not likely be reasonable for a state to invoke RULOF for a class of facilities under these emission guidelines. That is, because there are relatively few affected EGUs in each subcategory and because each EGU is likely to have a distinct combination of size, operating process, footprint, geographic location, *etc.*, it is highly unlikely that the same threshold analysis would apply to two or more units.

i. Invoking RULOF for Long-Term Coal-Fired Steam Generating EGUs

In determining the BSER for the long-term coal-fired steam generating EGUs, the EPA considered several evaluation metrics specific to CCS. However, affected EGUs are not required to implement CCS to comply with their standards of performance. To the extent a state is considering whether it is reasonable for a particular affected EGU in this subcategory to achieve the degree of emission limitation using CCS as the control strategy, the state would consider whether that affected EGU's circumstances are fundamentally different from the evaluation metrics and information the EPA considered in these emission guidelines. If a state is considering whether it is reasonable for an affected EGU to achieve the degree of emission limitation for long-term coal-fired steam generating EGUs through some other control strategy, certain of the evaluation metrics and information the EPA considered, such as overall costs and energy requirements, would be relevant while other metrics or information may or may not be.

As discussed above, the EPA considered costs in terms of $/ton CO_2 reduced and $/MWh. The Agency broke down its cost consideration for CCS into capture costs and CO_2 transport and sequestration costs, as discussed in sections VIII.D.1.a.ii.(A) and (B) of this preamble. The EPA also considered the availability of the IRC section 45Q tax credit in evaluating the cost of CCS for affected EGUs, and finally, evaluated the impacts of two different capacity factor assumptions on costs. Similarly, the Agency considered a number of evaluation metrics specific to CCS under the non-air quality health and environmental impacts and energy requirements factors, in addition to considering non-greenhouse gas emissions and parasitic/auxiliary energy demand increases and the net power output decreases. In particular, the EPA considered water use, CO_2 capture plant siting, transport and geologic sequestration, and impacts on the energy sector in terms of long-term structure and reliability of the power sector. A state may also consider other factors and circumstances that the EPA did not consider in its evaluation of CCS, to the extent such factors or circumstances are relevant to the reasonableness of achieving the associated degree of emission limitation.

As detailed in section VII.D.1.a.i of this preamble, the EPA has determined that CCS is adequately demonstrated for long-term coal-fired steam generating EGUs. The Agency evaluated the components of CCS both individually and in concurrent, simultaneous operation. If a state believes a particular affected EGU cannot reasonably implement CCS based on physical impossibility or technical infeasibility, the state must demonstrate that the circumstances of that individual EGU are fundamentally different from the information on CCS that the EPA considered in these emission guidelines.

ii. Invoking RULOF for Medium-Term Coal-Fired Steam Generating EGUs

As for the long-term coal-fired steam generating EGU subcategory, the EPA also considered evaluation metrics and information specific to the BSER, natural gas co-firing, for the medium-term subcategory. Again, similar to the long-term subcategory, certain generally applicable metrics and information that the EPA considered, *e.g.*, overall costs and energy requirements, will be relevant regardless of the control strategy a state is considering for an affected EGU in the medium-term subcategory. To the extent a state is considering whether it is reasonable for a particular affected EGU to reasonably achieve the presumptive standard of performance using natural gas co-firing as a control, the state should evaluate whether there is a fundamental difference between the circumstances of that EGU and the information the EPA considered. In considering costs for natural gas co-firing, the Agency took into account costs associated with adding new gas burners and other boiler modifications, fuel cost, and new natural gas pipelines. In considering non-air quality health and environmental impacts and energy requirements, the EPA addressed losses in boiler efficiency due to co-firing, as well as non-greenhouse gas emissions and impact on the structure of the energy sector. States may also consider other factors and circumstances that are relevant to determining the reasonableness of achieving the applicable degree of emission limitation.

iii. Invoking RULOF To Apply a Longer Compliance Schedule

Under 40 CFR 60.24a(c), ''final compliance,'' *i.e.*, compliance with the applicable standard of performance, ''shall be required as expeditiously as practicable but no later than the compliance times specified'' in the applicable emission guidelines, unless a state has demonstrated that a particular designated facility cannot reasonably comply with the specific compliance time per the RULOF provision at 40 CFR 60.24a(e). The EPA, in these emission guidelines, has detailed the amount of time needed for states and affected EGUs in the long-term and medium-term coal-fired steam generating EGU subcategories to comply with standards of performance using CCS and natural gas co-firing, respectively, in sections VII.C.1 and VII.C.2 of this preamble. These compliance times are based on information available for and applicable to the subcategories as a whole. The

[925] 88 FR 80517 (November 17, 2023).

Agency anticipates that some affected EGUs will be able to comply more expeditiously than on these generally applicable timelines. Similarly, there may be circumstances in which a particular EGU cannot reasonably comply with its standard of performance by the compliance date specified in these emission guidelines. In order to provide a longer compliance schedule, the state must demonstrate that there is a fundamental difference between the information the EPA considered for the subcategory as a whole and the circumstances of a particular EGU. These circumstances should not be speculative; the state must substantiate the need for a longer compliance schedule with documentation supporting that need and justifying why a certain component or components of implementation will take longer than the EPA considered in these emission guidelines. If a state anticipates that a process or activity will take longer than is typical for similarly situated EGUs within and outside the state or longer than it has historically, the state should provide an explanation of why it expects this to be the case as well as evidence corroborating the reasons and need for additional time. Consistent with 40 CFR 60.24a(c) and (e), states should not use the RULOF provision to provide a longer compliance schedule unless there is a demonstrated, documented reason at the time of state plan submission that a particular source will not be able to achieve compliance by the date specified in these emission guidelines. The EPA notes that it is providing a number of flexibilities in these final emission guidelines for states and sources if they find, subsequent to state plan submission, that additional time is necessary for compliance; states should consider these flexibilities in conjunction with the potential use of RULOF to provide a longer compliance schedule. A source-specific compliance date pursuant to RULOF must be no later than necessary to address the fundamental difference; that is, it must be as close to the compliance schedule provided in these emission guidelines as reasonably possible. Considerations specific to providing a longer compliance schedule to address reliability are addressed in section X.C.2.e.i of this preamble.

Comment: Several commenters stated that the EPA must respect the broad authority granted to states under the CAA and that while the EPA's information on various factors is helpful to states, states may readily deviate from the emission guidelines in order to account for source- and state-specific characteristics. The commenters argued that the EPA's general implementing regulations at 40 CFR 60.24a(c) recognize that states may consider factors that make application of a less stringent standard of performance or longer compliance time significantly more reasonable, and commenters stated that those factors should include, *inter alia,* cost, feasibility, infrastructure development, NSR implications, fluctuations in performance depending on load, state energy policy, and potential reliability issues. The commenters stated that states have the authority to account for consideration of other factors in various ways and that the EPA must defer to state choices, provided those choices are reasonable and consistent with the statute.

Response: Comments on states' use of RULOF vis-à-vis the EPA's determinations pursuant to CAA section 111(a)(1) in the applicable emission guidelines are outside the scope of this rulemaking.[926] Similarly, comments on the EPA's authority to review states' use of RULOF in state plans and the scope of that review are outside the scope of this rulemaking.[927] The EPA is also clarifying that, while the commenters are correct that the general implementing regulations at 40 CFR 60.24a(c) recognize that states may invoke RULOF to provide a less stringent standard of performance or longer compliance schedule, they also provide that, unless the threshold for the use of RULOF in 40 CFR 60.24a(e) has been met, ''standards of performance shall be no less stringent than the corresponding emission guideline(s) . . . and final compliance shall be required as expeditiously as practicable but no later than the compliance times specified'' in the emission guidelines. The threshold for invoking RULOF is when a state demonstrates that a particular affected EGU cannot reasonably achieve the degree of emission limitation determined by the EPA, based on one or more of the circumstances at 40 CFR 60.24a(e)(i)–(iii), because there are fundamental differences between the information the EPA considered in the emission guidelines and the information specific to the affected EGU. The ''significantly more reasonable'' standard does not apply to RULOF determinations under these emission guidelines.[928]

The EPA agrees that states have authority to consider ''other circumstances specific to the facility.'' States are uniquely situated to have knowledge about unit-specific considerations. If a unit-specific factor or circumstance is fundamentally different from the information the EPA considered and that difference makes it unreasonable for the affected EGU to achieve that degree of emission limitation or compliance schedule,[929] it is grounds for applying a less stringent standard of performance or longer compliance schedule. The EPA will review states' RULOF analyses and determinations for consistency with the applicable regulatory requirements at 40 CFR 60.24a(e)–(h).

Comment: Multiple commenters weighed in on the subject of cost metrics. Two commenters stated that the EPA should not require states to consider costs using the same metrics that it considered in the emission guidelines. These commenters explained that the unique circumstances of each unit mean that different metrics may be appropriate and should be allowed as long as the state plan provides a justification. Other commenters, however, supported the proposed requirement for states to consider costs using the same metrics as the EPA. Similarly, commenters differed on the example in the proposed rule preamble that costs that are greater than the 95th percentile of costs on a fleetwide basis would likely be fundamentally different from the fleetwide costs that the EPA considered in these emission guidelines. While one commenter believed that the 95th percentile may not be an appropriate threshold in all circumstances and should not be treated as an absolute, another commenter argued that the EPA should formalize the 95th percentile threshold as a requirement for states seeking to invoke RULOF based on unreasonable cost.

Response: The EPA believes that, in order to evaluate whether there is a fundamental difference between the cost information the EPA considered in these emission guidelines and the cost information for a particular affected EGU, it is necessary for states to evaluate costs using the same metrics that the EPA considered. However, states are not precluded from considering additional cost metrics alongside the two metrics used in these emission guidelines: $/ton of CO_2 reduced and $/MWh of electricity

[926] See 88 FR 80509–17 (November 17, 2023).

[927] See *id.* at 80526–27.

[928] 40 CFR 60.20a(a).

[929] ''Other factors'' may include facility-specific circumstances and factors that the EPA did not anticipate and consider in the applicable emission guideline that make achieving the EPA's degree of emission limitation unreasonable for that facility. 88 FR 80480, 80521 (November 17, 2023).

generated. States should justify why any additional cost metrics are relevant to determining whether a particular affected EGU can reasonably achieve the applicable degree of emission limitation.

The EPA did not state that a cost that is greater than the 95th percentile of fleetwide costs would necessarily justify invocation of RULOF. Nor did the EPA intend to suggest that such costs are the only way states can demonstrate that the costs for a particular affected EGU are fundamentally different. While it may be an appropriate benchmark in some cases, there are other ways for states to demonstrate that the cost for a particular affected EGU is an outlier. That is, the EPA is not requiring that the unit-specific costs be above the 95th percentile in order to demonstrate that they are fundamentally different from the costs the Agency considered in these emission guidelines. As discussed elsewhere in this section of the preamble, the diversity in circumstances of individual affected EGUs under these emission guidelines makes it infeasible for the EPA to *a priori* define a bright line for what constitutes reasonable versus unreasonable costs for individual units in these emission guidelines.

Comment: One commenter noted that the EPA should only approve the use of RULOF to provide a longer compliance schedule where there is clearly documented evidence (*e.g.*, receipts, invoices, actual site work) that a source is making best endeavors to achieve compliance as expeditiously as possible.

Response: The EPA believes this kind of evidence is strong support for providing a longer compliance schedule. The Agency further believes that states should show that the need to provide a longer compliance schedule is notwithstanding best efforts on the parts of all relevant parties to achieve timely compliance. The EPA is not, however, precluding the possibility that states could reasonably justify a longer compliance schedule based on other types of information or evidence.

b. Calculation of a Standard of Performance That Accounts for RULOF

If a state has demonstrated that a particular affected EGU is unable to reasonably achieve the applicable degree of emission limitation or compliance schedule under these emission guidelines per 40 CFR 60.24a(e), it may then apply a less stringent standard of performance or longer compliance schedule according to the process laid out in 40 CFR 60.24a(f). Pursuant to that process, the state must determine the standard of performance or compliance schedule that, respectively, is no less stringent or no longer than necessary to address the fundamental difference that was the basis for invoking RULOF. That is, the standard of performance or compliance schedule must be as close to the EPA's degree of emission limitation or compliance schedule as reasonably possible for that particular EGU.

The EPA notes that the proposed emission guidelines would have included requirements for how states determine less stringent standards of performance, including what systems of emission reduction states must evaluate and the order in which they must be evaluated. These proposed requirements were intended to ensure that states reasonably consider the controls that may qualify as a source-specific BSER.[930] However, the final RULOF provisions in subpart Ba for determining less stringent standards of performance differ from the proposed subpart Ba provisions in a way that obviates the need for the separate requirements proposed in these emission guidelines. First, as opposed to determining a source-specific BSER for sources that have met the threshold requirements for RULOF, states determine the standard of performance that is no less stringent than the EPA's degree of emission limitation than necessary to address the fundamental difference. Second, the process for determining such a standard of performance that the EPA finalized at 40 CFR 60.24a(f)(1) involves evaluating, to the extent necessary, the systems of emission reduction that the EPA identified in the applicable emission guidelines using the factors and evaluation metrics that the Agency considered in assessing those systems. Because the final RULOF provisions of subpart Ba create essentially the same process as the provisions the EPA proposed for determining a less stringent standard of performance under these emission guidelines, the EPA has determined it is not necessary to finalize those provisions here.

The EPA anticipates that states invoking RULOF for affected EGUs will do so because an EGU is in one of two circumstances: it is implementing the control strategy the EPA determined is the BSER but cannot achieve the degree of emission limitation in the emission guideline using that control (or any other system of emission reduction); or it is not implementing the BSER and cannot reasonably achieve the degree of emission limitation using any system of emission reduction.

If an affected EGU will be implementing the BSER but cannot meet the degree of emission limitation due to fundamental differences between the circumstances of that particular EGU and the circumstances the EPA considered in the emission guidelines, it may not be necessary for the state to evaluate other systems of emission reduction to determine the less stringent standard of performance. In this instance, the state and affected EGU would determine the degree of emission limitation the EGU can reasonably achieve, consistent with the requirement that it be no less stringent than necessary. That degree of emission limitation would be the basis for the less stringent standard of performance. For example, assume an affected EGU in the long-term coal-fired steam generating EGU subcategory is intending to install CCS and the state has demonstrated that it is not reasonably possible for the capture equipment at that particular EGU to achieve 90 percent capture of the mass of CO_2 in the flue gas (corresponding to an 88.4 percent reduction in emission rate), but it can reasonably achieve 85 percent capture. If the source cannot reasonably achieve an 88.4 percent reduction in emission rate using any other system of emission reduction, the state may apply a less stringent standard of performance that corresponds to 85 percent capture without needing to evaluate further systems of emission reduction.

In other cases, however, an affected EGU may not be implementing the BSER and may not be able to reasonably achieve the applicable degree of emission limitation (*i.e.*, the presumptive standard of performance) using any control strategy. In such situations, the state must determine the standard of performance that is no less stringent than necessary by evaluating the systems of emission reduction the EPA considered in these emission guidelines, using the factors and evaluation metrics the EPA considered in assessing those systems. States may also consider additional systems of emission reduction that the EPA did not identify but that the state believes are available and may be reasonable for a particular affected EGU.

The requirement at 40 CFR 60.24a(f)(1) provides that a state must evaluate these systems of emission reduction *to the extent necessary* to determine the standard of performance that is as close as reasonably possible to the presumptive standard of performance under these emission guidelines. It will most likely not be necessary for a state to consider all of the systems that the EPA identified for a given affected EGU. For example, if the state has already determined it is not

[930] See 88 FR 33384 (May 23, 2023).

reasonably possible for an affected EGU to implement one of these control strategies, at any stringency, as part of its demonstration under 40 CFR 60.24a(e) that a less stringent standard of performance is warranted, the state does not need to evaluate that system again. Similarly, if a state starts by evaluating the system that achieves the greatest emission reductions and determines the affected EGU can implement that system, it is most likely not necessary for the state to consider the other systems on the list in order to determine that the resulting standard of performance is no less stringent than necessary. The Agency anticipates that states will leverage the information the EPA has provided regarding systems of emission reduction in these emission guidelines, as well as the wealth of other technical, cost, and related information on various control systems in the record for this final action, in conducting their evaluations under 40 CFR 60.24a(f). In many cases, it will be possible for states to use information the EPA has provided as a starting point and particularize it for the circumstances of an individual affected EGU.[931]

For systems of emission reduction that have a range of potential stringencies, states should start by evaluating the most stringent iteration that is potentially feasible for the particular affected EGU. If that level of stringency is not reasonable, the state should also evaluate other stringencies as may be needed to determine the standard of performance that is no less stringent than the applicable degree of emission limitation in these emission guidelines than necessary.

In evaluating the systems of emission reduction identified in these emissions guidelines, states must also consider the factors and evaluation metrics that the EPA considered in assessing those systems, including technical feasibility, the amount of emission reductions, any non-air quality health and environmental impacts, and energy requirements. 40 CFR 60.24a(f)(1). They may also consider, in evaluating systems of emission reduction, other factors specific to the facility that constitute a fundamental difference between the information the EPA considered and the circumstances of the particular affected EGU and that were the basis of invoking RULOF for that particular EGU. For example, if a state determined that it is physically impossible or technically infeasible and/or unreasonably costly for a long-term coal-fired affected EGU to construct a CO_2 pipeline because the EGU is located on a remote island, the state could consider that information in evaluating additional systems of emission reduction, as well.

The general implementing regulations at 40 CFR 60.24a(f)(2) provide that any less stringent standards of performance that a state applies pursuant to RULOF must be in the form required by the applicable emission guideline. The presumptive standards of performance the EPA is providing in these emission guidelines are rate-based emission limitations. In order to ensure that a source-specific standard of performance is no less stringent than the EPA's presumptive standard than necessary, the source-specific standard pursuant to RULOF must be determined and expressed in the form of a rate-based emission limitation. That is, the systems of emission reduction that states evaluate pursuant to 40 CFR 60.24a(f)(1) must be systems for reducing a source's emission rate and the state must apply a standard of performance expressed as an emission rate, in lb CO_2/MWh,[932] that is no less stringent than necessary. As discussed in section X.D.1.b of this preamble, the EPA is not providing that affected EGUs with standards of performance pursuant to consideration of RULOF can use mass-based or rate-based compliance flexibilities under these emission guidelines.

The general implementing regulations also provide that any compliance schedule extending more than twenty months past the state plan submission deadline must include legally enforceable increments of progress. 40 CFR 60.24a(d). Due to the timelines the EPA is finalizing under these emission guidelines, any affected EGU with compliance obligations pursuant to consideration of RULOF will have a compliance schedule that triggers the need for increments of progress in state plans. Because compliance obligations pursuant to RULOF are, by their nature, source-specific, the EPA is not providing particular increments of progress for sources for which RULOF has been invoked in these emission guidelines. Therefore, states must provide increments of progress for RULOF sources in their state plans that comply with the generally applicable requirements in 40 CFR 60.24a(d) and 40 CFR 60.21a(h).

Additionally, 40 CFR 60.24a(h) requires that a less stringent standard of performance must meet all other applicable requirements of both the general implementing regulations and these emission guidelines.

i. Determining a Less-Stringent Standard of Performance for Long-Term Coal Fired Steam Generating EGUs

The EPA identified four potential systems of emission reduction for long-term coal-fired steam generating EGUs: CCS with 90 percent CO_2 capture, CCS with partial CO_2 capture/lower capture rates, natural gas co-firing, and HRI. If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular affected coal-fired EGU in the long-term subcategory can install and operate CCS but cannot reasonably achieve an 88.4 percent degree of emission limitation using CCS or any other systems of emission reduction, under the process laid out in 60.24a(f)(1) the state would proceed to evaluate CCS with lower rates of CO_2 capture. The state would identify the most stringent degree of emission limitation the affected EGU can reasonably achieve using CCS and that degree of emission limitation would become the basis for the source's less stringent standard of performance.[933]

If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular affected coal-fired EGU cannot reasonably install and operate CCS as a control strategy and cannot otherwise achieve the presumptive standard of performance, the state would proceed to evaluate natural gas co-firing and HRI as potential control strategies. Because 40 CFR 60.24a(f)(1) requires that a standard of performance be no less stringent than necessary to address the fundamental differences that were the basis for invoking RULOF, states would start by evaluating natural gas co-firing at 40 percent. If the affected EGU cannot

[931] See, *e.g.*, sections VII.C.1–4 of this preamble, the final TSD, *GHG Mitigation Measures for Steam Generation* Units, the CO_2 Capture Project Schedule and Operations Memo, Documentation for the Lateral Cost Estimation, Transport and Storage Timeline Summary, and the Heat Rate Improvement Method Costs and Limitations Memo.

[932] The presumptive standards of performance for coal-fired steam-generating affected EGUs and base load and intermediate load natural gas- and oil-fired steam generating affected EGUs are in units of lb CO_2/MWh; thus, any standards of performance pursuant to consideration of RULOF must be determined in these units, as well. The presumptive standard of performance for low-load natural gas-fired and oil-fired affected EGUs are in units of lb CO_2/MMBtu. While the EPA does not expect that states will use the RULOF provisions to provide less stringent standards of performance for these sources because their BSER is based on uniform fuels, should a state do so, the standard of performance would be determined in units of lb CO_2/MMBtu.

[933] 40 CFR 60.24a(f) requires that a standard of performance pursuant to consideration of RULOF be no less stringent than necessary to address the fundamental difference identified under 40 CFR 60.24a(e). If a particular affected EGU can install and operate CCS but only at such a low CO_2 capture rate that it could reasonably achieve greater stringency based on natural gas co-firing, the state would apply a standard of performance based on natural gas co-firing.

reasonably co-fire at 40 percent, the state would proceed to evaluate lower levels of natural gas co-firing unless it has demonstrated that the EGU cannot reasonably co-fire any amount of natural gas. If that is the case, the state would then evaluate HRI as a control strategy. The EPA notes that states may also consider additional systems of emission reduction that may be available and reasonable for particular EGUs.

ii. Determining a Less-Stringent Standard of Performance for Medium-Term Coal Fired Steam Generating EGUs

The EPA identified three potential systems of emission reduction for affected coal-fired steam generating EGUs in the medium-term subcategory: CCS, natural gas co-firing, and HRI. The EPA explained in section VII.D.2.b.i of this preamble that the cost effectiveness of CCS is less favorable for medium-term steam generating EGUs based on the short periods they have to amortize capital costs and utilize the IRC section 45Q tax credit. The EPA therefore believes that it would be reasonable for states determining a less stringent standard of performance for an affected EGU in the medium-term subcategory to forgo evaluating CCS as a potential control strategy. States would therefore start by evaluating lower levels of natural gas co-firing, unless a state has demonstrated pursuant to 40 CFR 60.24a(e) that the particular EGU cannot reasonably install and implement natural gas co-firing as a system of emission reduction. If that is the case, the state would evaluate HRI as the basis for a standard of performance that is no less stringent than necessary.

The EPA expects that any coal-fired steam generating EGU to which a less stringent standard of performance is being applied will be able to reasonably implement some system of emission reduction; at a minimum, the Agency believes that all sources could institute approaches to maintain their historical heat rates.

iii. Determining a Longer Compliance Schedule

Pursuant to 40 CFR 60.24a(f)(1), a longer compliance schedule pursuant to consideration of RULOF must be no longer than necessary to address the fundamental difference identified pursuant to 40 CFR 60.24a(e). For states that are providing extensions to the schedules in the EPA's emission guidelines, implementation of this requirement is straightforward. States should provide any information and analyses discussed in other sections of this preamble as relevant to justifying the need for, and length of, any compliance schedule extensions under the RULOF provisions. For states that are applying less stringent standards of performance that are based on a system of emission reduction other than the BSER for that subcategory, states should apply a compliance schedule consistent with installation and implementation of that system that is as expeditious as practicable.[934]

Comment: One commenter asserted that the 2023 proposed rule indicated that states invoking RULOF would be required to evaluate certain controls, in a certain order, as appropriate for subcategories of affected EGUs. The commenter stated that the EPA must defer to states' consideration of other systems of emission reduction that the EPA has determined are not the BSER, including the manner in which the states choose to consider those systems.

Response: The EPA is not finalizing the proposed requirements in these emission guidelines that would have specified the systems of emission reduction that states must consider when invoking RULOF and the order in which they consider them. The EPA is instead providing that states' analyses and determinations of less stringent standards of performance pursuant to RULOF must be conducted in accordance with the generally applicable requirements of the part 60, subpart Ba implementing regulations; specifically, 40 CFR 60.24a(f). While the requirements under this regulation for determining less stringent standards of performance pursuant to RULOF are similar to the requirements proposed under these emission guidelines, they are also, as described above, more flexible because they provide (1) that states must consider other systems of emission reduction *to the extent necessary* to determine the standard of performance that is no less stringent than the EPA's degree of emission limitation than necessary, and (2) that states may consider other systems of emission reduction, in addition to those the EPA identified in the applicable emission guidelines.

c. Contingency Requirements

Per the general implementing regulations at 40 CFR 60.24a(g), if a state invokes RULOF based on an operating condition within the control of an affected EGU, such as remaining useful life or a specific level of utilization, the state plan must include such operating condition or conditions as an enforceable requirement. The state plan must also include provisions that provide for the implementation and enforcement of the operating conditions, including requirements for monitoring, reporting, and recordkeeping. The EPA notes that there may be circumstances in which an affected EGU's circumstances change after a state has submitted its state plan; states may always submit plan revisions if needed to alter an enforceable requirement therein.

Comment: One commenter stated that if a state does not accept the presumptive standards of performance for a facility, it must establish federally enforceable retirement dates and operating conditions for that facility. The commenter asserted that the CAA does not authorize the EPA to constrain states' discretion by requiring them to impose such restrictions as the price for exercising the RULOF authority granted by Congress. The commenter suggested that the EPA eliminate the requirement to include enforceable retirement dates and restrictions on operations in conjunction with a RULOF determination and stated that states should retain discretion to decide whether and when, based on RULOF, it is necessary to impose such restrictions on sources.

Response: The EPA clarifies that states are in no way required to impose enforceable retirement dates or operating restrictions on affected EGUs under these emission guidelines. It is entirely within a state's control to decide whether such a requirement is appropriate for a source. If a state determines that it is, in fact, appropriate to codify an affected EGU's intention to cease operating or limit its operations as an enforceable requirement, the state may use such considerations as the basis for applying, as warranted, a less stringent standard of performance to that source. This allowance is provided under the subpart Ba general implementing regulations, 40 CFR 60.24a(g).

d. More Stringent Standards of Performance in State Plans

States always have the authority and ability to include more stringent standards of performance and faster compliance schedules as federally enforceable requirements in their state plans. They do not need to use the RULOF provisions to do so. See 40 CFR 60.24a(i).

e. Interaction of RULOF and Other State Plan Flexibilities and Mechanisms

The EPA discusses the ability of affected EGUs with standards of performance determined pursuant to 40 CFR 60.24a(f) to use compliance

[934] See 40 CFR 60.24a(c).

flexibilities under these emission guidelines in section X.D of this preamble.

i. Use of RULOF To Address Reliability

The EPA, in determining the degree of emission limitation achievable through application of the BSER for coal-fired steam generating EGUs, analyzed potential impacts of the BSERs on resource adequacy in addition to considering multiple studies on how reliability could be impacted by these emission guidelines. In doing so, the Agency considered potential large-scale (regional and national) and long-term impacts on the reliability of the electricity system under CAA section 111(a)(1)'s ''energy requirements'' factor. In evaluating CCS as a control strategy for long-term coal-fired steam generating EGUs, the Agency determined that CCS as the BSER would have limited and non-adverse impacts on the long-term structure of the power sector or on reliability of the power sector. See section VII.C.1.a.iii.(F) and final TSD, *Resource Adequacy Analysis*. Additionally, the EPA has made several adjustments to the final emission guidelines relative to proposal that should have the effect of alleviating any reliability concerns, including changing the scope of units covered by these actions and removing certain subcategories, including one that would have included an annual capacity factor limitation. See section XII.F of this preamble for further discussion.

While the EPA has determined that the structure and requirements of these emission guidelines will not negatively impact large-scale and long-term reliability, it also acknowledges the more locationally specific, source-by-source decisions that go into maintaining grid reliability. For example, there may be circumstances in which a balancing authority may need to have a particular unit available at a certain time in order to ensure reliability of the larger system. As noted above, the structure and various mechanisms of these emission guidelines allow states and reliability authorities to plan for compliance in a manner that preserves grid operators' abilities to maintain electric reliability. Specifically, coal-fired EGUs that are planning to cease operation do not have control requirements under these emission guidelines, the removal of the imminent-term and near-term subcategories means that states and reliability authorities have greater flexibility in the earlier years of implementation, and the EPA is providing two dedicated reliability mechanisms. Given these adjustments, the Agency believes there will remain very few, if any, circumstances in which states will need to provide particularized compliance obligations for an affected EGU based on a need to address reliability. However, there may be isolated instances in which a particular affected EGU cannot reasonably comply with the applicable requirements due to a source-specific reliability issue. Such unit-specific reliability considerations may constitute an ''[o]ther circumstance[] specific to the facility'' that makes it unreasonable for a particular EGU to achieve the degree of emission limitation or compliance schedule the EPA has provided in these emission guidelines. 40 CFR 60.24a(e)(1)(iii). The EPA is therefore confirming that states may use the RULOF provisions in 40 CFR 60.24a to apply a less stringent standard of performance or longer compliance schedule to a particular affected EGU based on reliability considerations. The EPA emphasizes that the RULOF provisions should not be used to provide a less stringent standard of performance if the applicable degree of emission limitation for an affected EGU is reasonably achievable. To do so would be inconsistent with CAA sections 111(d) and 111(a)(1). Thus, to the extent states and affected EGUs find it necessary to use RULOF to particularize these emission guidelines' requirements for a specific unit based on reliability concerns, such adjustments should take the form of longer compliance schedules.

In order to meet the threshold for applying a less stringent standard of performance or longer compliance schedule based on unit-specific reliability considerations under 40 CFR 60.24a(e), a state must demonstrate a fundamental difference between the information the EPA considered on reliability and the circumstances of the specific unit. This demonstration would be made by showing that requiring a particular affected EGU to comply with its presumptive standard of performance under the specified compliance timeframe would compromise reliability, *e.g.*, by necessitating that the affected EGU be taken offline for a specific period of time during which a resource adequacy shortfall with adverse impacts would result. In order to make this demonstration, states must provide an analysis of the reliability risk if the particular affected EGU were required to comply with its applicable presumptive standard of performance by the compliance date, clearly demonstrating that the EGU is reliability critical such that requiring it to comply would trigger non-compliance with at least one of the mandatory reliability standards approved by FERC or cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region. Specifically, this requires a clear demonstration that each unit for which use of RULOF is being considered would be needed to maintain the targeted level of resource adequacy.[935] The analysis must also include a projection of the period of time for which the particular affected EGU is expected to be reliability critical. States must also provide an analysis by the relevant reliability Planning Authority[936] that corroborates the asserted reliability risk and confirms that one or both of the circumstances would result from requiring the particular affected EGU to comply with its applicable requirements, and also confirms the period of time for which the EGU is projected to be reliability critical. The state plan must also include a certification from the Planning Authority that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested.

To substantiate a reliability risk that stems from resource adequacy in particular, the analyses must also demonstrate that the specific affected EGU has been designated by the relevant Planning Authority as needed for resource adequacy and thus reliability, and that requiring that affected EGU to comply with the requirements in these emission guidelines would interfere with its ability to serve this function as intended by the Planning Authority. However, the EPA reiterates that the structure of the subcategories for coal-fired steam generating affected EGUs in these final emission guidelines differs from the proposal in ways that should provide states and affected EGUs wider latitude to make the operational decisions needed to ensure resource adequacy. Thus, again, the Agency expects that the circumstances in which states need to rely on consideration of RULOF to

[935] See, *e.g.*, the North American Electric Reliability Corporation's ''Probabilistic Assessment: Technical Guideline Document,'' August 2016. *https://www.nerc.com/comm/RSTC/PAWG/proba_technical_guideline_document_08082014.pdf*.

[936] The North American Electric Reliability Corporation (NERC)'s currently enforceable definition of ''Planning Authority'' is, ''[t]he responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.'' Glossary of Terms Used in NERC Reliability Standards, Updated April 1, 2024. *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf*.

particularize an affected EGU's compliance obligation will be rare.

The EPA will review these analyses and documentation as part of its evaluation of standards of performance and compliance schedules that states apply based on consideration of reliability under the RULOF provisions.

As described in sections X.C.1.d and XII.F.3.b of this preamble, the EPA is providing two flexible mechanisms that states may incorporate in their plans that, if utilized, would provide a temporary delay of affected EGU's compliance obligations if there is a demonstrated reliability need.[937] The EPA anticipates that states discovering, after a state plan has been submitted and approved, that a particular affected EGU needs additional time to meet its compliance obligation as a result of a reliability or resource adequacy issue will avail themselves of these flexibilities. If a state anticipates that the reliability or resource adequacy issue will persist beyond the 1-year extension provided by these flexible mechanisms, the EPA expects that states will also initiate a state plan revision. In such a state plan revision, the state must make the demonstration and provides the analysis described above in order to use to adjust an affected EGU's compliance obligations to address the reliability or resource adequacy issue at that time.

The EPA intends to continue engagement on the topic of electric system reliability, resource adequacy, and linkages to various EPA regulatory efforts to ensure proper communication with key stakeholders and Federal counterparts including DOE and FERC. Additionally, the Agency intends to coordinate with its Federal partners with expertise in reliability when evaluating RULOF demonstrations that invoke this consideration. There are also opportunities to potentially provide information and technical support on implementation of these emission guidelines and critical reliability considerations that will benefit states, affected sources, system planners, and reliability authorities. Specifically, the DOE–EPA MOU on Electric System Reliability provides a framework for ongoing engagement, and the EPA intends to work with DOE to ensure that reliability stakeholders have additional and ongoing opportunities to engage EPA on this important topic.

Comment: The EPA received multiple comments on the use of the RULOF provisions to address reliability. Several commenters emphasized that states need the ability to adjust affected EGUs' compliance obligations for reasons linked to reliability. They elaborated that an independent system operator/regional transmission organization determination that an affected EGU is needed for reliability would be anchored in a RULOF analysis that considers forces that may drive the unit's premature retirement. Some commenters indicated that use of RULOF to address such units would allow those units to continue to operate for the required period of time, applying routine methods of operation, to address grid reliability. They similarly noted that sources that have foreseeable retirement glidepaths but are key resources could be offered a BSER that promotes the EPA's carbon reduction goals but falls outside of the Agency's one-size-fits-all BSER approach.

Another commenter suggested that states should be able to modify a subcategory in their plans to address a reliability issue, and provided the example of allowing a unit that is planning to retire at the end of 2032 but that is needed for reliability purposes at greater than 20 percent capacity factor to subcategorize as an imminent-term unit despite operating past the end date for the imminent-term subcategory. The commenter suggested that such a modification could be justified under both the remaining useful life consideration and the energy requirements consideration of RULOF. Other commenters similarly requested that the EPA clarify that the RULOF provisions can be used to accommodate the changes in the power sector, *e.g.,* the build-out of transmission and distribution infrastructure, that are ongoing and that may impact the anticipated operating horizons of some affected EGUs.

Response: As explained above, the EPA has analyzed the potential impacts of these emission guidelines and determined that they would have limited and non-adverse impacts on large-scale and long-term reliability and resource adequacy. However, the EPA acknowledges that there may be reliability-related considerations that apply at the level of a particular EGU that the Agency could not have known or foreseen and did not consider in its broader assessment. As described above, states may use the RULOF provision to address reliability or resource adequacy if they demonstrate, based on the analysis and consultation with planning authorities described in this section of this preamble, that there is a fundamental difference between the information the EPA considered in these emission guidelines and the circumstances and information relevant to a particular affected EGU that makes it unreasonable for that EGU to comply with its presumptive standard of performance by the applicable compliance date.

The EPA stresses that a generic or unsubstantiated reliability or resource adequacy concern is not sufficient to substantiate a fundamental difference or unreasonableness of complying with applicable requirements. Simply asserting that grid reliability or resource adequacy is a concern for a state and thus an affected EGU needs a less stringent standard of performance or longer compliance schedule would not be sufficient. Rather, a state would have to demonstrate, via the certification and analysis described above, that the relevant planning authority has designated a particular affected EGU as reliability or resource adequacy critical and that requiring that EGU to comply with its standard of performance by the applicable compliance date would interfere with the maintenance of reliability or resource adequacy as intended by that planning authority.

A standard of performance or compliance schedule that has been particularized for an affected EGU based on consideration of reliability or resource adequacy must, pursuant to 40 CFR 60.24a(f), be no less stringent than necessary to address the fundamental difference identified pursuant to 40 CFR 60.24a(e), which in this case would be unit-specific grid reliability or resource adequacy needs. A less stringent standard of performance does not necessarily correspond to a standard of performance based on routine methods of operation and maintenance.

The EPA notes that states do not need to use the RULOF provisions to justify the date on which a particular affected EGU plans to cease operation. RULOF only comes into play if there is a fundamental difference between the information the EPA considered and the information specific to an affected EGU with a shorter remaining useful life that makes achieving the EPA's presumptive standard of performance unreasonable,, *e.g.,* the amortized cost of control. If a state elects to rely on an affected EGU's operating conditions, such as a plan to permanently cease operation, as the basis for applying a less stringent standard of performance, those conditions must be included as an

[937] The mechanism described in section X.C.1.d of this preamble is not restricted to circumstances in which a state needs to provide an affected EGU with additional time to comply with its standard of performance specifically for reliability or resource adequacy, but it can be used for this purpose. The reliability mechanism described in section XII.F.3.b is specific to reliability and can be used to extend the date by which a source plans to cease operating by up to 1 year.

enforceable commitment in the state plan.

As explained elsewhere in this section of the preamble, the effect of RULOF is not to modify subcategories under these emission guidelines but rather to particularize the compliance obligations of an affected EGU within a given subcategory. The EPA also notes that it is not finalizing the proposed imminent-term or near-term subcategories for affected coal-fired steam generating EGUs.

ii. Use of RULOF With Compliance Date Extension Mechanism

As discussed in section X.C.1.d of the preamble to this final rule, the EPA is allowing states to include in their plans a mechanism to provide a compliance deadline extension of up to 1 year for certain affected EGUs. This mechanism would be available for affected EGUs with standards of performance that require add-on control technologies and that demonstrate the extension is needed for installation of controls due to circumstances outside the control of the affected EGU. In the event the state and affected EGU believe that 1 year will not be sufficient to remedy those circumstances, *i.e.,* that the affected EGU will not be able to comply with its standard of performance even with a 1-year extension, the state may also start the process of revising its plan to apply a longer compliance schedule based on consideration of RULOF. In order to demonstrate that there is a fundamental difference between the circumstances of the affected EGU and the information the EPA considered in determining the compliance schedule in the emission guidelines, the state should provide documentation to justify why it is unreasonable for the affected EGU to meet that compliance schedule, even with an additional year (providing that the state has allowed for a 1-year extension), based on one or more of the considerations in 40 CFR 60.24a(e)(1). This documentation should demonstrate that the need to provide a longer compliance schedule was due to circumstances outside the affected EGU's control and that the affected EGU has met all relevant increments of progress and other obligations in a timely manner up to the point at which the delay occurred. That is, the state must demonstrate that the need to invoke RULOF and to provide a longer compliance schedule was not caused by self-created circumstances. As discussed in sections X.C.1.d and X.C.2.a of this preamble, documentation such as permits obtained and/or contracts entered into for the installation of control technology, receipts, invoices, and correspondence with vendors and regulators is helpful evidence for demonstrating that states and affected EGUs have been making progress towards compliance and that the need for a longer compliance schedule is due to circumstances outside the affected EGU's control.

In establishing a longer compliance schedule pursuant to 40 CFR 60.24a(f)(1), a state must demonstrate that the revised schedule is no longer than necessary to accommodate circumstances that have resulted in the delay.

3. Increments of Progress for Medium-Term and Long-Term Coal-Fired Steam Generating EGUs

The EPA's longstanding CAA section 111 implementing regulations provide that state plans must include legally enforceable Increments of Progress (IoPs) toward achieving compliance for each designated facility when the compliance schedule extends more than a specified length of time from the state plan submission date. Under the subpart Ba revisions finalized in November 2023, IoPs are required when the final compliance deadline (*i.e.,* the date on which affected EGUs must start monitoring and reporting emissions data and other information for purposes of demonstrating compliance with standards of performance) is more than 20 months after the plan submittal deadline. These emission guidelines for steam EGUs finalize a 24-month state plan submission deadline and compliance dates of January 1, 2032 (for long-term coal-fired EGUs), and January 1, 2030 (for all other steam generating EGUs), exceeding subpart Ba's 20-month threshold. Under these emission guidelines, in particular, the lengthy planning and construction processes associated with the CCS and natural gas co-firing BSERs make IoPs an appropriate mechanism to assure steady progress toward compliance and to provide transparency on that progress.

The EPA received support for the proposed approach to IoPs from many commenters; others, however, offered adverse perspectives. Supportive commenters generally emphasized the need for clear, transparent, and enforceable implementation checkpoints between state plan submittal and the compliance dates given the lengthy timelines affected EGUs are being afforded to achieve their standards of performance. These comments were broadly consistent with the proposed rationale for the IoPs. Adverse comments are addressed at the end of this subsection of the preamble.

The EPA is finalizing IoPs for affected EGUs based on BSERs that involve installation of emissions controls: long-term coal-fired EGUs and medium-term coal-fired EGUs. Units complying through the BSER specified for each subcategory, either CCS for the long-term subcategory or natural gas co-firing for the medium-term subcategory, must use IoPs tailored to those BSERs. Units complying through a different control technology must adopt increments that correspond to each of the steps in 40 CFR 60.21a(h). As specified in the proposal, each increment must be assigned a calendar date deadline, but states have discretion to set those dates based on the unique circumstances of each unit. The EPA is also finalizing its proposal to exempt the natural gas- and oil-fired EGU subcategories from IoP requirements. These subcategories have BSERs of routine operation and maintenance, which does not require the installation of significant new emission controls or operational changes.

The EPA is finalizing the proposed approach allowing states to choose the calendar dates for all IoPs for long- and medium-term coal-fired EGUs, subject to two constraints. The IoP corresponding to 40 CFR 60.21a(h)(1), submittal of a final control plan to the air pollution control agency, must be assigned the earliest calendar date deadline among the increments, and the IoP corresponding to 40 CFR 60.21a(h)(5), final compliance, must be assigned a date aligned with the compliance date for each subcategory, either January 1, 2032, for the long-term subcategory or January 1, 2030, for the medium-term subcategory. The EPA believes that this approach will provide states and EGUs with flexibility to account for idiosyncrasies in planning processes, tailor compliance timelines to individual facilities, allow simultaneous work toward separate increments, and ensure full performance by the compliance date.

For coal-fired EGUs assigned to the long-term and medium-term subcategories and that adopt the corresponding BSER (CCS or natural gas co-firing, respectively) as their compliance strategy, the EPA is finalizing BSER-specific IoPs that correspond to the steps in 40 CFR 60.21a(h). Some increments have been adjusted to more closely align with planning, engineering, and construction steps anticipated for affected EGUs that will be complying with standards of performance with natural gas co-firing or CCS, in particular; however, these technology-specific increments retain the basic structure and substance of the increments in the general implementing regulations under subpart Ba. In addition, consistent with 40 CFR 60.24a(d), the EPA is finalizing similar additional increments of progress for the long-term and medium-term coal-fired subcategories that are specific to pipeline construction in order to ensure timely progress on the planning, permitting, and construction activities related to pipelines that may be required to enable full compliance with the applicable standard of performance. The EPA is also finalizing an additional increment of progress related to the identification of an appropriate sequestration site for the long-term coal-fired subcategory. Finally, the EPA is finalizing a requirement that state plans must require affected EGUs with increments of progress to post the activities or actions that constitute the increments, the schedule required in the state plan for achieving them, and, within 30 business days, any documentation necessary to demonstrate that they have been achieved to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, in a timely manner.

For coal-fired steam generating units in the long-term subcategory adopting CCS as their compliance approach, the EPA is finalizing the following seven IoPs as enforceable elements required to be included in a state plan: (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan and must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or FEED study, the anticipated timeline to achieve full compliance, and the benchmarks anticipated along the way. (2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded. (3) Initiation of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CO_2 capture on an annual basis. (4) Completion of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CO_2 capture on an annual basis. (5) Demonstration that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process(es), a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities. (6) Submittal of a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities. (7) Final compliance with the standard of performance. States must assign calendar deadlines for each increment consistent with the following requirements: the first increment, submission of a final control plan, must be assigned the earliest calendar date among the increments; the seventh increment, final compliance must be set for January 1, 2032.

For coal-fired steam generating units in the long-term subcategory adopting a compliance approach that differs from CCS, the EPA is finalizing the requirement that states adopt IoPs for each affected EGU that are consistent with the IoPs at 40 CFR 60.21a(h). As with long-term units adopting CCS as their compliance strategy, states must assign calendar deadlines for each increment consistent with the following requirements: the first increment, corresponding to 40 CFR 60.21a(h)(1), must be assigned the earliest calendar date among the increments; the final increment, corresponding to 40 CFR 60.21a(h)(5), must be set for January 1, 2032.

For coal-fired steam generating units in the medium-term subcategory adopting natural gas co-firing as their compliance approach, the EPA is finalizing the following six IoPs as enforceable elements required to be included in a state plan: (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan and must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks anticipated along the way. (2) Awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish such modifications. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded. (3) Initiation of onsite construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis. (4) Completion of onsite construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis. (5) Demonstration that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting application process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permit applications is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities. (6) Final compliance with the standard of performance. States must also assign calendar deadlines for each increment consistent with the following requirements: the first increment, submission of a final control plan, must be assigned the earliest calendar date among the increments; the sixth increment, final compliance, must be set for January 1, 2030.

For coal-fired steam generating units in the medium-term subcategory adopting a compliance approach that differs from natural gas co-firing, the EPA is finalizing the requirement that states adopt IoPs for each affected EGU that are consistent with the increments in 40 CFR 60.21a(h).

As with medium-term units adopting natural gas co-firing as their compliance strategy, states must assign calendar deadlines for each increment consistent with the following requirements: the first increment, corresponding to 40 CFR 60.21a(h)(1), must be assigned the earliest calendar date among the increments; the final increment, corresponding to 40 CFR 60.21a(h)(5), must be set for January 1, 2030.

The EPA notes that if an affected EGU receives approval for a compliance date extension, the date for at least one, if not several, IoPs must be adjusted to align with the revised compliance date. The new dates for the relevant IoPs must be specified in the application for the extension. The EPA notes that the last increment—final compliance—should be no later than 1 year after the original compliance date, pursuant to the requirements described in section X.C.1.d.

Comment: The EPA received comments that the proposed IoPs are too restrictive and may limit certain implementation flexibilities, namely that the burden to adjust IoPs after state plan submittal will limit sources' ability to switch subcategories or adjust implementation timelines due to unforeseen circumstances.

Response: The EPA has considered these comments and notes that the final rule includes planning flexibilities to address these situations. The first of these flexibilities is embedded in the subpart Ba regulations governing optional state plan revisions. Plan revisions, including revisions to subcategory assignments and any corresponding IoPs, may be used at a state's discretion to account for changes in planned compliance approaches. 40 CFR 60.28a. Such revisions can also include RULOF-based adjustments to approved standards of performance as well as the timelines to meet those standards, including the IoPs. Further, as mentioned above, the compliance date extension mechanism described in section X.C.1.d allows for modification of the IoPs to align with an approved compliance date extension. In addition, the subcategory structure of these final emission guidelines differs from that at proposal such that it is less likely that affected coal-fired EGUs will switch subcategories. In the event that an affected EGU does switch between the long-term and medium-term subcategories, the state plan revision process is the most appropriate mechanism because a different control strategy may be appropriate. Based on this consideration and the availability of planning flexibilities to account for changes in compliance plans and changed circumstances, the EPA is finalizing the approach to IoPs as proposed.

Comment: Some commenters raised concerns related to length of time between the state plan submittal deadline and the final compliance dates, namely that some IoPs will take place too far into the future to be reliably assigned calendar date deadlines.

Response: As noted above, the EPA has concluded that length of time between the state plan submittal deadline and the compliance deadlines for units in the medium-term and long-term subcategories as well as the anticipated complexity for units to comply with the final standards of performance necessitate the use of discrete interim checkpoints prior to final compliance, formally established as increments of progress, to ensure timely and transparent progress toward each unit's compliance obligation. It would be inconsistent to determine that the same factors necessitating the increments—the length of time between the state plan submittal deadline and the compliance obligation as well as the complex nature of the implementation process—also eliminate the IoPs' core accountability function by prohibiting the assignment of calendar date deadlines. Finally, as described above, the final emission guidelines also allow states and affected EGUs significant flexibility to determine when each increment applies.

Comment: Some commenters raised concerns that the IoPs could limit affected EGUs from selecting compliance approaches that differ from the BSER technology associated with each subcategory, namely averaging and trading.

Response: Under the approach finalized in this rule, units assigned to the long-term and medium-term subcategories that do not adopt the associated BSER as part of their compliance strategy must establish date-specified IoPs consistent with the subpart Ba IoPs codified at 40 CFR 60.21a(h). That is, states will particularize the generic IoPs in subpart Ba as appropriate for affected EGUs that comply with their standards of performance using control technologies other than CCS (for long-term units) or natural gas co-firing (for medium-term units). The EPA discusses considerations relevant to averaging and trading in section X.D of this preamble.

4. Reporting Obligations and Milestones for Affected EGUs That Plan to Permanently Cease Operations

The EPA proposed legally enforceable reporting obligations and milestones for affected EGUs demonstrating that they plan to cease operations and use that voluntary commitment for eligibility for the imminent-term, near-term, or medium-term subcategory. No reporting obligations and milestones were proposed for affected EGUs within the long-term subcategory since a voluntary commitment to cease operations was not part of the subcategory's applicability criteria. The proposed rationale for the milestone requirements recognized that the proposed subcategories were based on the operating horizons of units within each subcategory, and that there were numerous steps that EGUs in these subcategories need to take in order to effectuate their commitments to cease operations. The proposed reporting obligations and milestones were intended to provide transparency and assurance that affected EGUs could complete the steps necessary to qualify for a subcategory with a less stringent standard of performance.[938]

Of the proposed subcategories for which the reporting obligations and milestones were proposed to apply, the EPA's final emission guidelines retain only the medium-term coal-fired subcategory. Though the EPA is finalizing only one subcategory with an associated operational time horizon, the Agency has determined that the original rationale for the milestones is still valid. That is, the BSER determination for EGUs assigned to the medium-term subcategory is contingent on sources within this subcategory having limited operating horizons relative to affected EGUs in the long-term subcategory, and the integrity of the subcategory approach and the environmental integrity of these emission guidelines depend on sources behaving consistent with the operating horizon they have represented in the state plan. The steps required for EGUs to cease operations are numerous and vary across jurisdictions; giving states, the EPA, and other stakeholders insight into these steps and affected EGUs' progress along these steps provides assurance that they are on track to meeting their state plan requirements. The reporting obligations and milestones the EPA is finalizing under these emission guidelines are a reasonable approach to assuring transparency and timely compliance; they can also serve as an early indication that a state plan revision may be necessary if it becomes apparent that an affected EGU is not meeting its designated milestones. Further, the agency has determined that a similar rationale for requiring reporting obligations and milestones applies to

[938] 88 FR 33390 (May 23, 2023).

affected EGUs that invoke RULOF based on a unit's remaining useful life. States may apply a less stringent standard of performance to a particular affected EGU if its shorter remaining useful life results in a fundamental difference between the circumstances of that EGU and the information the EPA considered, and that difference makes it unreasonable for the EGU to achieve the presumptive standard of performance. However, if such a unit continues to operate past the date by which it previously committed to cease operating, the basis for the less stringent standard of performance is abrogated and the environmental integrity of the emission guidelines compromised. Therefore, as for affected EGUs in the medium-term subcategory, the reporting obligations and milestones are an essential component of assuring that affected EGUs that invoke RULOF based on a unit's remaining useful life are actually able to satisfy the condition of receiving the less stringent standard in the first instance.

The EPA is finalizing the following milestones and reporting requirements, explained in more detail below, for both affected EGUs assigned to the medium-term subcategory and affected EGUs that invoke RULOF based on a unit's remaining useful life. These sources must submit an Initial Milestone Report five years before the date by which it will permanently cease operations, annual Milestone Status Reports for each intervening year between the initial report and the date operations will cease, and a Final Milestone Status Report no later than six months from the date by which the affected EGU has committed to cease operating.

Commenters expressed a range of views regarding the proposed reporting obligations and milestones. Some were broadly supportive of the reporting milestones and the EPA's stated rationale to provide a mechanism to help ensure that affected EGUs progress steadily toward a commitment to cease operations when that commitment affects the stringency of their standard of performance. Summaries of and responses to additional comments on the reporting obligations and milestones are addressed at the end of this subsection.

The discussion below refers to reporting "milestones." Owners/operators of sources take a number of process steps in preparing a unit to cease operating (*i.e.*, preparing it to deactivate). The EPA is requiring that states select certain of these steps to serve as milestones for the purpose of reporting where a source is in the process; the EPA is designating two milestones in particular and states will select additional steps for reporting milestones. The requirements being established under these emission guidelines do not require milestone steps to be taken at any particular time—they merely require reporting on when a source intends to reach each of its designated milestones and whether and when it has actually done so. The reporting obligations and milestone requirements count backward from the calendar date by which an affected EGU has committed to permanently cease operations, which must be included in the state plan, to monitor timely progress toward that date. Five years before any planned date to permanently cease operations or 60 days after state plan submission, whichever is later, the owner or operator of affected EGUs must submit an Initial Milestone Report to the applicable air pollution control agency that includes the following: (1) A summary of the process steps required for the affected EGU to permanently cease operation by the date included in the state plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. (2) A list of key milestones that will be used to assess whether each process step has been met, and calendar day deadlines for each milestone. These milestones must include at least the initial notice to the relevant reliability authority of an EGU's deactivation date and submittal of an official retirement filing with the EGU's reliability authority. (3) An analysis of how the process steps, milestones, and associated timelines included in the Initial Milestone Report compare to the timelines of similar EGUs within the state that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines. (4) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization (RTO), independent system operator (ISO), balancing authority, public utility commission (PUC), or other applicable authority; any deactivation-related reliability assessments conducted by the RTO or ISO; and any filings pertaining to the EGU with the United States Securities and Exchange Commission (SEC) or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which the plans for the EGU are mentioned; any integrated resource plans and PUC orders approving the EGU's deactivation; any reliability analyses developed by the RTO, ISO, or relevant reliability authority in response to the EGU's deactivation notification; any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and any notification to or from an RTO, ISO, or balancing authority altering the timing of deactivation for the EGU.

For each of the remaining years prior to the date by which an affected EGU has committed to permanently cease operations that is included in the state plan, it must submit an annual Milestone Status Report that addresses the following: (1) Progress toward meeting all milestones identified in the Initial Milestone Report; and (2) supporting regulatory documents and relevant SEC filings, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority to demonstrate compliance with or progress toward all milestones.

The EPA is also finalizing a provision that affected EGUs with reporting milestones associated with commitments to permanently cease operations would be required to submit a Final Milestone Status Report no later than 6 months following its committed closure date. This report would document any actions that the unit has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

The EPA is finalizing a requirement that affected EGUs with reporting milestones for commitments to permanently cease operations must post their Initial Milestone Report, annual Milestone Status Reports, and Final Milestone Status Report, including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the Carbon Pollution Standards for EGUs website, as described in section X.E.1.b, within 30 business days of being filed. The EPA recognizes that applicable regulatory authorities, retirement processes, and retirement approval criteria will vary across states and affected EGUs. The proposed milestone reporting requirements are intended to establish a general framework flexible enough to account for significant differences across jurisdictions while assuring timely planning toward the dates by which affected EGUs permanently cease operations.

Comment: Some commentors questioned the need for the milestone reports by pointing to existing closure enforcement mechanisms within their jurisdictions.

Response: The existence of enforceable mechanisms in some jurisdictions does not obviate the need for the reporting milestones under these emission guidelines. First, the closure requirements, the nature of the enforcement mechanisms, and process requirements to cease operations will vary across different jurisdictions, and some jurisdictions may lack mechanisms entirely. The reporting milestones framework sets a uniform floor for reporting progress toward a commitment to cease operations, reducing differences in the quality and scope of information available to the EPA and public regarding closures. Second, the reporting milestones under these emission guidelines serve the additional purpose of transparency and allowing all stakeholders to have access to information related to affected EGUs' ongoing compliance.

Comment: Some commentors noted the unique EGU closure processes within their own jurisdictions and expressed concern as to whether the milestones requirements were too rigid to accommodate them.

Response: The reporting milestones are designed to create a flexible reporting framework that can accommodate differences in state closure processes. States can satisfy the required elements of the milestone reports by explaining how the process steps for plant closures within their jurisdiction work and establishing milestones corresponding to the process steps required within individual jurisdictions.

5. Testing and Monitoring Requirements

a. Emissions Monitoring and Reporting

The EPA proposed to require that state plans must include a requirement that affected EGUs monitor and report hourly CO_2 mass emissions emitted to the atmosphere, total heat input, and total gross electricity output, including electricity generation and, where applicable, useful thermal output converted to gross MWh, in accordance with the 40 CFR part 75 monitoring, reporting, and recordkeeping requirements. The EPA is finalizing a requirement that affected EGUs must use a 40 CFR part 75 certified monitoring methodology and report the hourly data on a quarterly basis, with each quarterly report due to the Administrator 30 days after the last day in the calendar quarter. The 40 CFR part 75 monitoring provisions require most coal-fired boilers to use a CO_2 continuous emissions monitoring system (CEMS), including both a CO_2 concentration monitor and a stack gas flow monitor. Some oil- and gas-fired boilers may have options to use alternative measurement methodologies (*e.g.*, fuel flow meters combined with fuel quality data).

The EPA received comments supporting and opposing the requirement to use 40 CFR part 75 monitoring, reporting, and recordkeeping requirements.

Comment: Commenters generally supported these requirements, noting that the majority of EGUs affected by this rule already monitor and submit emissions reports under 40 CFR part 75 under existing programs, including the Acid Rain Program and/or Regional Greenhouse Gas Initiative—a cooperative of several states formed to reduce CO_2 emissions from EGUs. In addition, EGUs that are not required to monitor and report under one of those programs may have 40 CFR part 75 certified monitoring systems in place for the MATS or CSAPR.

Response: The EPA agrees with these comments. Relying on the same monitors that are certified and quality assured in accordance with 40 CFR part 75 reduces implementation costs and ensures consistent emissions data across regulatory programs.

Comment: Some commenters focused on potential measurement bias of 40 CFR part 75 certified monitoring systems, with commenters split on whether the data are biased high or low.

Response: The EPA disagrees that the data reported under 40 CFR part 75 are biased significantly high or low. Each CO_2 CEMS must undergo regular quality assurance and quality control activities including periodic relative accuracy test audits (RATAs) where a monitoring system is compared to an independent monitoring system using EPA reference methods and NIST-traceable calibration gases. In a May 2022 study conducted by the EPA, the absolute value of the median difference between EGUs' monitoring systems and independent monitoring systems using EPA reference methods was found to be approximately 2 percent for CO_2 concentration monitors and stack gas flow monitors in the years 2017 through 2021.[939]

b. CCS-Specific Technology Monitoring and Reporting

Affected EGUs employing CCS must comply with relevant monitoring and reporting requirements specific to CCS. As described in the proposal, the CCS process is subject to monitoring and reporting requirements under the EPA's GHGRP (40 CFR part 98). The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the U.S. The "suppliers of carbon dioxide" source category of the GHGRP (GHGRP subpart PP) requires those affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied. Facilities that inject a CO_2 stream underground for long-term containment in subsurface geologic formations report quantities of CO_2 sequestered under the "geologic sequestration of carbon dioxide" source category of the GHGRP (GHGRP subpart RR). In April 2024, to complement GHGRP subpart RR, the EPA finalized the "geologic sequestration of carbon dioxide with enhanced oil recovery (EOR) using ISO 27916" source category of the GHGRP (GHGRP subpart VV) to provide an alternative method of reporting geologic sequestration in association with EOR.[940 941 942]

As discussed in section VII.C.1.a.vii, the EPA is finalizing a requirement that any affected unit that employs CCS technology that captures enough CO_2 to meet the standard and injects the captured CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility subject to the GHGRP requirements, and the facility injecting the CO_2 underground must

[939] Zintgraff, Stacey. 2022. Monitoring Insights: Relative Accuracy in EPA CAMD's Power Sector Emissions Data. *www.epa.gov/system/files/documents/2022-05/Monitoring%20Insights-%20Relative%20Accuracy.pdf.*

[940] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[941] International Standards Organization (ISO) standard designated as CSA Group (CSA)/American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (referred to as "CSA/ANSI ISO 27916:2019").

[942] As described in 87 FR 36920 (June 21, 2022), both subpart RR and subpart VV (CSA/ANSI ISO 27916:2019) require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. Primary differences relate to the terms in their respective mass balance equations, how each defines leakage, and when facilities may discontinue reporting.

report under GHGRP subpart RR or GHGRP subpart VV. These emission guidelines do not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC program under the Safe Drinking Water Act.

The EPA also notes that compliance with the standard is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic sequestration site are not part of that calculation, though the EPA anticipates that the quantity of CO_2 sequestered will be substantially similar to the quantity captured. To verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, we are leveraging regulatory requirements under the GHGRP. The BSER is determined to be adequately demonstrated based solely on geologic sequestration that is not associated with EOR. However, EGUs also have the compliance option to send CO_2 to EOR facilities that report under GHGRP subpart RR or GHGRP subpart VV. We also emphasize that these emission guidelines do not involve regulation of downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. The requirement that the emitting EGU transfer the captured CO_2 to an entity subject to the GHGRP requirements is thus exclusively an element of enforcement of the EGU standard. This will avoid duplicative monitoring, reporting, and verification requirements between this proposal and the GHGRP, while also ensuring that the facility injecting and sequestering the CO_2 (which may not necessarily be the EGU) maintains responsibility for these requirements. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of the final emission guidelines.

D. Compliance Flexibilities

In the finalized subpart Ba revisions, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d),* the EPA explained that, under its interpretation of CAA section 111, each state is permitted to include compliance flexibilities, including flexibilities that allow affected EGUs to meet their emission limits in the aggregate, in their state plans. The EPA also explained that, in particular emission guidelines, the Agency may limit compliance flexibilities if necessary to protect the environmental outcomes of the guidelines.[943] Thus, in the subpart Ba final rule the EPA returned to its longstanding position that CAA section 111(d) authorizes the EPA to approve state plans that achieve the requisite emission limitation through aggregate reductions from their sources, including through trading or averaging, where appropriate for a particular emission guideline and consistent with the intended environmental outcomes under CAA section 111.[944]

In developing both the proposed and final emission guidelines, the EPA heard from stakeholders that flexibilities are important in complying with standards of performance under these emission guidelines. The EPA proposed to allow states to incorporate emission trading and averaging into their plans under these emission guidelines, provided that states ensure that the use of such flexibilities will result in an aggregate level of emission reduction that is equivalent to each source individually achieving its standard of performance.

Specifically, a variety of commenters from states, industry, RTO/ISOs, and NGOs emphasized the importance of allowing states to incorporate not only flexibilities that allow sources to demonstrate compliance in the aggregate, such as emission trading and averaging, but also unit-specific mass-based compliance into their plans. In particular, commenters expressed a strong preference for mass-based compliance mechanisms, whether unit-specific or emission trading, and cited reliability as a key driver of their support for such mechanisms. However, for the most part commenters did not provide detail on how flexibilities could be designed under the unique circumstances of these emission guidelines. In addition, many commenters did not specify as to the usefulness of certain compliance flexibilities for steam generating EGUs versus combustion turbine EGUs. Because these final emission guidelines only apply to steam generating EGUs, there are fewer affected EGUs that could partake in these flexibilities, which may limit their usefulness. A description of and responses to general comments on these compliance flexibilities can be found at the end of this subsection.

The EPA notes that many other features of the final emission guidelines provide the type of flexibility that the commenters stated they wanted through the use of emission trading, averaging, and/or unit-specific mass-based compliance. First, as noted in section X.C.1.b of this preamble, compliance with presumptively approvable rate-based standards of performance is demonstrated on an annual basis, which already provides flexibility around mass emissions over an annual period (*i.e.,* it affords the affected EGU the ability over the course of the year to vary its emission output, which may be useful if, for example, it needs to temporarily turn off its control equipment or otherwise increase its emission rate). Second, the EPA is finalizing two mechanisms, described in section XII.F of this preamble, to address reliability concerns raised by commenters: a short-term reliability mechanism that allows affected EGUs to operate above their standard of performance for a limited time in periods of emergency and a reliability assurance mechanism to ensure sufficient capacity is available. Finally, as described in section X.C.2 of this preamble, states may invoke RULOF to provide for less stringent standards of performance for affected EGUs under certain circumstances (states may invoke RULOF both at the time of initial state plan development as well as through state plan revision should the circumstances of an affected EGU change following state plan submission).

The EPA believes that the use of compliance flexibilities, within the parameters specified in these emission guidelines, may provide some additional operational flexibility to states and affected EGUs in achieving the required emission reductions which, under these emission guidelines, are achieved specifically through cleaner performance. In particular, for aggregate compliance flexibilities like emission averaging and trading, affected EGUs may be able to capitalize on heterogeneity in economic emission reduction opportunities based on minor differences in marginal emission abatement costs and/or operating parameters among EGUs. This heterogeneity may provide some incentive among participating EGUs to overperform (*i.e.,* operate even more cleanly than required by the applicable standard of performance, because of the opportunity to sell compliance

[943] 88 FR 80533 (November 17, 2023).

[944] The EPA has authorized trading or averaging as compliance methods in several emission guidelines. See, *e.g.,* 70 FR 28606, 28617 (May 18, 2005) (Clean Air Mercury Rule authorized trading) (vacated on other grounds); 40 CFR 60.24(b)(1) (subpart B CAA section 111 implementing regulations promulgated in 2005 allow states' standards of performance to be based on an "allowance system"); 80 FR 64662, 64840 (October 23, 2015) (CPP authorizing trading or averaging as a compliance strategy). In the recent final emission guidelines for the oil and natural gas industry, the EPA also finalized a determination that states are permitted sources to demonstrate compliance in the aggregate. 89 FR 16820 (March 8, 2024).

instruments to other units), while also providing some limited opportunity for other sources to vary their emission output.

Therefore, the EPA is finalizing a determination that the use of compliance flexibilities, including emission trading, averaging, and unit-specific mass-based compliance, is permissible for affected EGUs in certain subcategories and in certain circumstances under these emission guidelines. Specifically, the EPA is allowing affected EGUs in the medium- and long-term coal-fired subcategories to utilize these compliance flexibilities. The scope of this allowance is tailored to ensure consistency with the fundamental principle under CAA section 111 that state plans maintain the stringency of the EPA's BSER determination and associated degree of emission limitation as applied through the EPA's presumptive standards of performance in the context of these emission guidelines. In addition, the EPA believes that the scope of this allowance is consistent and appropriate for providing an incentive for overperformance. Relatedly, the EPA is also providing further elaboration on what it means for states to demonstrate that implementation of a standard of performance using a rate- or mass-based flexibility is at least as stringent as unit-specific implementation of affected EGUs' standards of performance. States are not required to allow their affected EGUs to use compliance flexibilities but can provide for such flexibilities at their discretion. In order for the EPA to find that a state plan that includes such flexibilities is "satisfactory," the state plan must demonstrate how it will achieve and maintain the requisite level of emission reduction.

The EPA stresses that any flexibilities involving aggregate compliance would be used to demonstrate compliance with an already-established standard of performance, rather than be used to establish a standard of performance in the first instance. The presumptive standards of performance that the EPA is providing in these emission guidelines are based on control strategies that are applied at the level of individual units. A compliance flexibility may change the way an affected EGU demonstrates compliance with a standard of performance (*e.g.,* by allowing that EGU to surrender allowances from another unit in lieu of reducing a portion of its own emissions), but does not alter the benchmark of emission performance against which compliance is evaluated. This is in contrast to the RULOF mechanism, which, as described in section X.C.2 of this preamble, states may use to apply a different standard of performance with a different degree of emission limitation than the EPA's presumptive standard. States incorporating trading or averaging would not need to undergo a RULOF demonstration for sources participating in trading or averaging programs because they are not altering those sources' underlying standards of performance—just providing an additional way for sources to demonstrate compliance.

While the EPA acknowledges widespread interest in the use of mass-based compliance, in the context of these particular emission guidelines, the Agency has significant concerns about the ability to demonstrate that mass-based compliance approaches achieve at least equivalent emission reduction as the application of rate-based, source-specific standards of performance. As explained in further detail in sections X.D.4 and X.D.5, the EPA is requiring the use of a backstop emission limitation, or backstop rate, in conjunction with mass-based compliance approaches (*i.e.,* for both unit-specific mass-based compliance and mass-based emission trading) for both the long-term and medium-term coal-fired subcategories. However, the EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach only for affected EGUs in the long-term subcategory. The use of mass-based compliance approaches—both unit-specific and trading—for affected EGUs in the medium-term coal-fired subcategory in particular poses a high risk of undermining the stringency of these emission guidelines due to inherent uncertainty about the future utilization of these sources. While the EPA is not precluding states from attempting to design mass-based approaches for affected EGUs in the medium-term coal-fired subcategory that satisfy the requirement of achieving at least equivalent stringency as rate-based implementation, the Agency was unable to devise an appropriate, implementable presumptively approvable approach for affected EGUs in the medium-term coal-fired subcategory and is therefore not providing one here. The EPA is also not providing a presumptively approvable approach to emission trading or averaging. Instead, the EPA intends to review emission trading or averaging programs in state plans on a case-by-case basis against the foundational principles for consistency with CAA section 111, as discussed in this section of the preamble.

Section X.D.1 of this preamble discusses the fundamental requirement that compliance flexibilities maintain the level of emission reduction of unit-specific implementation, in order to inform states' consideration of such flexibilities for any use in their state plans. It also addresses why limitations on the use of compliance flexibilities for certain subcategories are necessary to maintain the intended environmental outcomes of these emission guidelines. Sections X.D.2, X.D.3, X.D.4, and X.D.5 discuss each available type of compliance flexibility and provide information on how they can be used in state plans under these emission guidelines. Section X.D.6 provides information on general implementation features of emission trading and averaging programs that states must consider if they develop such a program. Section X.D.7 discusses interstate emission trading. Finally, section X.D.8 discusses considerations related to existing state programs and the inclusion of compliance flexibilities in a state plan under these emission guidelines.

Comment: Commenters cited a variety of reasons supporting the use of compliance flexibilities, such as emission trading, averaging, and unit-specific mass-based compliance, in these emission guidelines, including the need for flexibility in meeting the degree of emission limitation defined by the BSER, the potential for more cost-effective compliance, and reliability purposes.

Response: The EPA believes that, in certain circumstances, these flexibilities can provide some operational and cost flexibility to states and affected EGUs in complying with these emission guidelines and their standards of performance in state plans. However, as described above, the EPA is addressing reliability-related concerns primarily through other structural changes and mechanisms under these emission guidelines (see section XII.F of this preamble) that may obviate the need to use compliance flexibilities specifically to address reliability concerns. As a general matter, the EPA believes that compliance flexibilities such as emission trading and averaging provide some incentive for overperformance that could be beneficial to states and affected EGUs.

The EPA is finalizing a determination that emission trading, averaging, and unit-specific mass-based compliance are permissible for certain subcategories under these emission guidelines, subject to the limitations described in section X.D.1 of this preamble. The EPA believes these limitations are necessary in the context of these emission guidelines in order to maintain the level of emission reduction of the EPA's BSER determination and corresponding degree of emission limitation.

Comment: Some commenters expressed opposition to the use of emission trading and averaging, citing the potential for emission trading and averaging programs to maintain or exacerbate existing disparities in communities with environmental justice concerns.

Response: The EPA is cognizant of these concerns and believes that emission trading and averaging are not necessarily incompatible with environmental justice. The EPA is including limitations on the use of compliance flexibilities in state plans that should help address these EJ concerns. As discussed in more detail in section X.D.1, the EPA is restricting certain subcategories from using trading or averaging as well as, for mass-based compliance mechanisms, requiring the use of a backstop rate, to ensure that the use of compliance flexibilities maintains the level of emission reduction of the EPA's BSER determination and corresponding degree of emission limitation as well as achieves the statutory objective of these emission guidelines to mitigate air pollution by requiring sources to operate more cleanly. The EPA notes that trading programs can be designed to include measures like unit-specific emission rates that assure that reductions and corresponding benefits accrue proportionally to communities with environmental justice concerns. The EPA also notes that states have the ability to add further features and requirements to emission trading and averaging programs than identified in these emission guidelines, or to forgo their use entirely.

Pursuant to the requirements of subpart Ba, states are required to conduct meaningful engagement on all aspects of their state plans with pertinent stakeholders. This would necessarily include any potential use of flexibilities for sources to demonstrate compliance with the proposed standards of performance through emissions trading or averaging. As discussed in greater detail in section X.E.1.b.i of this preamble, meaningful engagement provides an opportunity for communities most affected by and vulnerable to the impacts of a plan to provide input, including input on any impacts resulting from the use of compliance flexibilities.

Comment: Some commenters stated that allowing trading or averaging is not consistent with the legal opinion in *West Virginia* v. *EPA*.

Response: This comment is outside the scope of this action. The EPA finalized its interpretation that CAA section 111 does not preclude states from including compliance flexibilities such as trading or averaging in their state plans (although the EPA may limit those flexibilities in particular emission guidelines if necessary to protect the environmental outcomes of those guidelines) when it revised the CAA section 111(d) implementing regulations in subpart Ba.[945] As described in the final subpart Ba revisions, "in *West Virginia* v. *EPA*, the Supreme Court did not directly address the state's authority to determine their sources' control measures. Although the Court did hold that constraints apply to the EPA's authority in determining the BSER, the Court's discussion of CAA section 111 is consistent with the EPA's interpretation that the provision does not preclude states from granting sources compliance flexibility."[946] The EPA further explained in the preamble to the subpart Ba final rule that the *West Virginia* Court was clear that the focus of the case was exclusively on whether the EPA acted within the scope of its authority in establishing the BSER: "The Court did not identify any constraints on the states in establishing standards of performance to their sources, and its holding and reasoning cannot be extended to apply such constraints."[947]

The EPA reiterates that, under these emission guidelines, the BSER determinations are emission reduction technologies or strategies that apply to and reduce the emission rates of individual affected EGUs. Furthermore, states have the option of including emission trading or averaging in their states plans but are by no means required to do so. States that choose to include trading or averaging programs in their state plans are required to demonstrate that those programs are in the aggregate as stringent as each affected EGU individually achieving its rate-based standard of performance. Additionally, as explained elsewhere in sections X.D.4 and X.D.5 of this preamble, the EPA is requiring the use of a backstop emission rate in conjunction with mass-based compliance flexibilities, one result of which is that units cannot comply with their standards of performance merely by shifting their generation to other electricity generators. Therefore, the EPA's BSERs in these emission guidelines are not based on generation shifting and, even if the EPA believed that *West Virginia* v. *EPA* implicated the use of compliance flexibilities, the permissible use of trading and averaging in this particular case does not implicate the Court's concerns about generation shifting therein.

[945] 88 FR 80480 80533–35 (November 17, 2023).

[946] 88 FR 80534 (November 17, 2023).

[947] 88 FR 80535 (November 17, 2023).

1. Demonstrating Equivalent Stringency

As stated in the section above, states are permitted to use emission trading, averaging, and unit-specific mass-based compliance in their plans for certain subcategories under these emission guidelines, provided that the plan demonstrates that any such use will achieve a level of emission reduction that is in the aggregate as environmentally protective as each affected EGU achieving its rate-based standard of performance. This requirement is rooted in the structure and purpose of CAA section 111. Most commenters supported the use of compliance flexibilities in these emission guidelines, and many explicitly expressed support for the EPA's stringency criterion in this context. Commenters also requested greater clarity on how to demonstrate equivalent stringency in a state plan. In this section, the EPA describes foundational parameters for a demonstration of equivalence in the state plan as well as limitations on the availability of compliance flexibilities for certain affected EGUs, which stem from the EPA's stringency criterion. Additionally, the EPA offers further explanation of how it will review state plan submissions to determine whether plans that include compliance flexibilities achieve an equivalent (or greater) level of emission reduction as each affected EGU individually complying with its unit-specific rate-based standard of performance.

a. Requirements for Demonstrating Equivalent Stringency

In their plans, states incorporating compliance flexibilities must first clearly demonstrate how they calculated the aggregate rate-based emission limitation (for rate-based averaging), mass limit (for unit-specific mass-based compliance), or mass budget (for mass-based emission trading) from unit-specific, rate-based presumptive standards of performance. (For rate-based trading, the standard of performance coupled with, if necessary, an adjustment based on the acquisition of compliance instruments, is used to demonstrate compliance.) In doing so, states must identify the specific affected EGUs that will be using compliance flexibilities; which flexibility each unit will able to use; the unit-specific, rate-based presumptive standard of performance; and the standard of performance established in the plan for each unit (rate-based limit or mass limit) or set of units (aggregate rate-based emission limitation or mass budget). The state must document and justify the assumptions made in calculating an aggregate rate-based emission limitation, mass limit, or mass budget, such as how the calculation is weighted or, for mass-based mechanisms, the level of utilization of participating affected EGUs used to calculate the mass limit or budget. This requirement is discussed in more detail in the context of each type of compliance flexibility in the following subsections.

Next, states must demonstrate how the compliance flexibility will maintain the requisite stringency, *i.e.,* how the plan will maintain the aggregate level of emission reduction that would be achieved if each unit was individually complying with its rate-based standard of performance. As discussed in section X.C.1 of this preamble, an affected EGU's standard of performance must generally be no less stringent than the corresponding presumptive standard of performance under these emission guidelines. This is true regardless of whether a standard of performance is expressed in terms of rate or mass. However, under an aggregate compliance approach, a unit may demonstrate compliance with that standard of performance by averaging its emission performance or trading compliance instruments (*e.g.,* allowances) with other affected EGUs. Here, to ensure consistency with the level of emission reductions Congress expected under CAA section 111(a)(1), the state must also demonstrate that the plan overall achieves equivalent stringency, *i.e.,* the same or better environmental outcome, as applying the EPA's presumptive standards of performance to each affected EGU (after accounting for any application of RULOF). That is, in order for the EPA to find a state plan ''satisfactory,'' that plan must achieve at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance (again, after accounting for any application of RULOF).

The requirement that state plans achieve equivalent stringency to the EPA's degree of emission limitation flows from the structure and purpose of CAA section 111, which is to mitigate air pollution that is reasonably anticipated to endanger public health or welfare. It achieves this outcome by requiring source categories that cause or contribute to dangerous air pollution to operate more cleanly. Unlike the CAA's NAAQS-based programs, section 111 is not designed to reach a level of emissions that has been deemed ''safe'' or ''acceptable''; there is no air-quality target that tells states and sources when emissions have been reduced ''enough.'' Rather, CAA section 111 requires affected sources to reduce their emissions to the level that the EPA has determined is achievable through application of the best system of emission reduction, *i.e.,* to achieve emission reductions consistent with the applicable presumptive standard of performance. Consistent with the statutory purpose of requiring affected sources to operate more cleanly, the EPA typically expresses presumptive standards of performance as rate-based emission limitations (*i.e.,* limitations on the amount of a regulated pollutant that can be emitted per unit of output, per unit of energy or material input, or per unit of time).

In the course of complying with a rate-based standard of performance under a state plan, an affected source takes actions that may or may not affect its ongoing emission reduction obligations. For example, a source may take certain actions that remove it from the source category, *e.g.,* by switching fuel type or permanently ceasing operations. Upon doing so, the source is no longer subject to the emission guidelines. Or an affected source may choose to change its operating characteristics in a way that impacts its overall mass of emissions, *e.g.,* by changing its utilization, in which case the source is still required to reduce its emission rate consistent with cleaner performance. In either instance, the changes in operation to one affected source do not implicate the obligations of other affected sources. Although changes to certain sources' operation may reduce emissions from the source category, they do not absolve the remaining affected EGUs from the statutory obligation to reduce their emission rates consistent with the level that the EPA has determined is achievable through application of the BSER. While state plans may, when permitted by the applicable emission guidelines, allow affected sources to translate their rate-based presumptive standards of performance into mass limits and/or comply with their standards of performance in the aggregate through averaging or trading, the fundamental statutory requirement remains: the state plan must demonstrate that, even if individual affected sources are not necessarily achieving their presumptive rate-based standards of performance, the plan as a whole must provide for the same level of emission reduction for the affected EGUs as though they were. While states may choose to allow individual sources to emit more or less than the degree of emission limitation determined by the EPA, any compliance flexibilities must be designed to ensure that their use does not erode the emission reduction benefits that would result if each source was individually achieving its presumptive standard of performance (after accounting for any use of RULOF).

For rate-based averaging and trading, discussed in more detail in sections X.D.2 and X.D.3 of this preamble, demonstrating an equivalent level of emission reduction is relatively straightforward, as a rate-based program inherently provides relatively stronger assurance of equivalence with individual rate-based standards of performance. This is due to the fact that the aggregate rate-based emission limitation (for rate-based averaging) or rate-based standard of performance with adjustment for compliance instruments (for rate-based trading) is calculated based on both the emission output and gross generation output (utilization) of the participating affected EGUs. In other words., a rate-based compliance flexibility, such as a rate-based unit-specific standard of performance, inherently adjusts for changes in utilization and preserves the imperative to operate more cleanly. For unit-specific mass-based compliance and mass-based trading, demonstrating equivalent stringency is more complicated, as the use of a mass limit or mass budget on its own may not guarantee that sources are achieving emission reductions commensurate with operating more cleanly. Thus the EPA is requiring that, in order to ensure that the emission outcome that would be achieved through unit-specific rate-based standards of performance are preserved, states must also include a backstop emission rate limitation, or backstop rate, for affected EGUs using a mass-based compliance flexibility, as discussed in more detail in sections X.D.4 and X.D.5 of this preamble. In addition, states employing a mass-based mechanism in their plans must show why assumptions underlying the calculation of utilization for the purposes of establishing a mass limit or mass budget are appropriately conservative to ensure an equivalent level of emission reduction, as discussed more in sections X.D.4 and X.D.5 of this preamble.

In sum, states wishing to employ compliance flexibilities in their state plans must demonstrate that the plan achieves at least equivalent stringency with each source individually achieving its standard of performance, bearing in mind the discussion and requirements in this section, as well as the discussion and requirements in the following sections specific to each type of mechanism. The EPA will review state plan submissions that include compliance flexibilities to ensure that they are consistent with CAA section 111's purpose of reducing dangerous air pollution by requiring sources to operate more cleanly. In order for the EPA to find a state plan ''satisfactory,'' that plan must address each affected EGU within the state and demonstrate that the plan overall achieves at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance, after accounting for any application of RULOF.

b. Exclusion of Certain Affected EGUs From Compliance Flexibilities

While the use of compliance flexibilities such as emission trading, averaging, and unit-specific mass-based compliance is generally permissible under these emission guidelines, the EPA indicated in the proposal that it may be appropriate for certain groups of sources to be excluded from using these flexibilities in order to ensure an equivalent level of emission reduction with each source individually achieving its standard of performance. In the proposed emission guidelines, the EPA expressed concerns about the use of compliance flexibilities for several subcategories that have BSER determinations of routine methods of operation and maintenance as well as those sources for which states have invoked RULOF to apply a less stringent standard of performance, as their inclusion may undermine the intended level of emission reduction of the BSER for other facilities. The EPA also questioned whether trading and averaging across subcategories should be limited in order to maintain the stringency of unit-specific compliance. Finally, the EPA questioned whether affected EGUs that receive the IRC section 45Q tax credit for permanent sequestration of CO_2 may have an overriding incentive to maximize both the application of the CCS technology and total electric generation, leading to source behavior that may be non-responsive to the economic incentives of a trading program.

In response to the request for comment on these concerns related to the appropriateness of emission trading and averaging for certain subcategories and for sources with a standard based on RULOF, the EPA received mixed feedback. Some commenters agreed with the EPA's concerns about these subcategories participating in trading and averaging and that affected EGUs in these subcategories should be prevented from participating in an emission trading or averaging program. However, several commenters said that it was indeed appropriate to allow all subcategories as well as sources with a standard of performance based on RULOF to participate in trading and averaging and that the program would still achieve an equivalent level of emission reduction, even if those subcategories are of limited stringency.

In response to the request for comment on whether emission trading and averaging should be allowed across subcategories in light of concerns over differing levels of stringency for different subcategories impacting overall achievement of an equivalent level of emission reduction, the EPA also received mixed feedback. Some commenters supported restricting trading and averaging across subcategories because of concerns that EGUs in a subcategory with a relatively higher stringency could acquire allowances from EGUs in a subcategory with a relatively lower stringency in order to comply instead of operating a control technology. Several commenters stated that trading across subcategories need not be limited because, as long as state plans are of an equivalent level of emission reduction, emission trading and averaging would still require the overall aggregate limit to be met.

Taking into consideration the comments on the proposed emission guidelines as well as changes made to the subcategories in the final emission guidelines, the Agency is finalizing the following restrictions on the use of compliance flexibilities by certain subcategories.

First, emission trading or averaging programs must not include affected EGUs for which states have invoked RULOF to apply less stringent standards of performance. The Agency believes that, because RULOF sources have a standard of performance tailored to individual source circumstances that is required to be as stringent as reasonably practicable, these sources should not need further operational flexibility and are also unlikely to be able to overperform to any significant or regular degree. This means that their participation in an emission trading or averaging program is, at best, unlikely to add any value to the program (in terms of opportunity for overperformance) or, at worst, may provide an inappropriate opportunity for other sources subject to a relatively more stringent presumptive standard of performance to underperform by obtaining compliance instruments from or averaging their emission performance with affected EGUs that are subject to a relatively less stringent standard of performance based on RULOF. This outcome undermines the ability of the state plan to demonstrate an equivalent level of emission reduction, as non-RULOF sources would face a reduced incentive to operate more cleanly. In addition, affected EGUs with a standard of performance based on RULOF are prohibited from using unit-specific mass-based compliance under these emission guidelines. This is due to the compounding uncertainty regarding how states will use RULOF to particularize the compliance obligations for an affected EGU and the future utilization of affected EGUs that may be subject to RULOF. The RULOF provisions are used where a particular EGU is in unique circumstances and may result in a less stringent standard of performance based on the BSER technology, a less stringent standard of performance based on a different control technology, a longer compliance schedule, or some combination of the three. The bespoke nature of compliance obligations pursuant to RULOF makes it difficult for the EPA to provide principles for and for states to design mass-based compliance strategies that ensure an equivalent level of emission reduction. Additionally, as previously discussed, there is a significant amount of uncertainty in the future utilization of certain affected EGUs, including those with standards of performance pursuant to RULOF. While there is no risk of implicating the compliance obligation of other sources in unit-specific mass-based compliance, the EPA believes that allowing RULOF sources to use unit-specific mass compliance would pose a significant risk in undermining the stringency of the state plan such that these sources may not be achieving the level of emission reduction commensurate with cleaner performance.

Second, emission trading or averaging programs may not include affected EGUs in the natural gas- and oil-fired steam subcategories. The BSER determination and associated degree of emission limitation for affected EGUs in these subcategories do not require any improvement in emission performance and already offer flexibility to sources to account for varying efficiency at different operating levels. As a result, these sources are unlikely to be responsive to an incentive towards overperformance, which means that their participation in an emission trading or averaging program is unlikely to add any value to the program (in terms of opportunity for overperformance). In addition, the EPA is concerned that the participation of these sources may undermine the program's equivalence with the presumptive standards of performance, because other steam sources, which have a relatively more stringent degree of emission limitation, may be inappropriately incentivized to underperform by obtaining compliance instruments from or averaging their emission performance with affected EGUs in the natural gas- and oil-fired steam subcategories. This outcome undermines the ability of the state plan to demonstrate equivalent stringency by reducing the incentive for sources to operate more cleanly. In addition, affected EGUs in the natural gas- and oil-fired steam subcategories are prohibited from using unit-specific mass-based compliance. While there is no risk of implicating the compliance obligation of other sources in unit-specific mass-based compliance, the EPA believes, as previously stated, there is already sufficient flexibility offered to sources in the natural gas- and oil-fired steam subcategories, as the basis for subcategorizing these sources takes into account their varying efficiency at different operating levels.

The EPA is allowing both coal-fired subcategories (both the medium- and long-term) to participate in all types of compliance flexibilities, within the parameters set by the EPA described in the following sections. The Agency believes, and many commenters agreed, that affected EGUs taking advantage of the IRC section 45Q tax credit may still benefit from the operational flexibility provided by emission trading and averaging, as well as unit-specific mass-based compliance. The Agency also believes that overperformance among these sources is possible and worth incentivizing through the use of compliance flexibilities. Incentivizing overperformance can lead to innovation in control technologies that, in turn, can lead to lower costs for, and greater emissions reductions from, control technologies.

The EPA is not finalizing a restriction on trading or averaging across subcategories for the two subcategories that are permitted to participate in these flexibilities. This means that affected EGUs in the medium-term coal-fired subcategory may trade or average their compliance with affected EGUs in the long-term coal-fired subcategory. With the aforementioned restrictions on participation in trading and averaging, the EPA does not see a need to further restrict the ability of eligible sources to trade or average with other sources.

2. Rate-Based Emission Averaging

The EPA proposed to permit states to incorporate rate-based averaging into their state plans under these emission guidelines. In general, rate-based averaging allows multiple affected EGUs to jointly meet a rate-based standard of performance. The scope of such averaging could apply at the facility level (*i.e.*, units located within a single facility) or at the owner or operator level (*i.e.*, units owned by the same utility). A description of and responses to comments received on rate-based averaging can be found at the end of this subsection.

As discussed in the proposed emission guidelines, averaging can provide potential benefits to affected sources by allowing for more cost effective and, in some cases, more straightforward compliance. First, averaging offers some flexibility for owners or operators to target cost effective reductions at certain affected EGUs. For example, owners or operators of affected EGUs might target installation of emission control approaches at units that operate more. Second, averaging at the facility level provides greater ease of compliance accounting for affected EGUs with a complex stack configuration (such as a common- or multi-stack configuration). In such instances, unit-level compliance involves apportioning reported emissions to individual affected EGUs that share a stack based on electricity generation or other parameters; this apportionment can be avoided by using facility-level averaging.

The EPA is finalizing a determination that rate-based averaging is permissible for affected EGUs in the medium- and long-term coal-fired subcategories. The scope of rate-based averaging may be at the facility level or at the owner/operator level within the state, as these are the circumstances under which rate-based averaging can provide significant benefits, as identified above, with minimal implementation complexity. Above this level (*i.e.*, across owner/operators or at the state or interstate level), the EPA has determined that a rate-based compliance flexibility must be implemented through rate-based trading, as described in section X.D.3 of this preamble. The EPA is establishing this limitation on the scope of averaging because it believes that the level of complexity associated with utilities, independent power producers, and states attempting to coordinate the real-time compliance information needed to assure that either all affected EGUs are meeting their individual standard of performance, or that a sufficient number of affected EGUs are overperforming to allow operational flexibility for other affected EGUs such that the aggregate standard of performance is being achieved, would curtail transparency and limit states', the EPA's, and stakeholders' abilities to track timely compliance. For example, dozens of units trying to average their emission rates would require owners or operators from different utilities and independent power producers to share operating and emissions data in real time. Thus, due to likely limitations on the timely availability of compliance-related information across owners and operators and across states, which is necessary to ensure aggregate compliance, the EPA believes that it is appropriate to limit the scope of rate-based averaging to the facility level or the owner/operator level within one state in order to provide greater compliance certainty and thus better demonstrate an equivalent level of emission reduction.

Demonstrating equivalence with unit-specific implementation of rate-based standards of performance in a rate-based averaging program is straightforward. A state would need to specify in its plan the group of affected EGUs participating in the averaging program that will demonstrate compliance on an aggregate basis, the unit-specific rate-based presumptive standard of performance that would apply to each participating affected EGU, and the aggregate compliance rate that must be achieved for the group of participating affected EGUs and how that aggregate rate is calculated, as described below. For states incorporating owner/operator-level averaging, the state plan would also need to include provisions that specify how the program will address any changes in the owner/operator for one or more participating affected EGUs during the course of program implementation to ensure effective implementation and enforcement of the program. Such provisions should be specified upfront in the plan and be self-executing, such that a state plan revision is not required to address such changes.

To ensure an equivalent level of emission reduction with application of individual rate-based standards of performance, the EPA is requiring that the weighting of the aggregate compliance rate is done on an output basis; in other words, participating affected EGUs must demonstrate compliance through achievement of an aggregate CO_2 emission rate that is a gross generation-based weighted average of the required standards of performance of each of the affected EGUs that participate in averaging. Such an approach is necessary to ensure that the aggregate compliance rate is representative of the unit-specific standards of performance that apply to each of the participating affected EGUs. Commenters were generally supportive of this method of calculating an aggregate rate for a group of sources participating in averaging. The Agency emphasizes that only affected EGUs are permitted to be included in the calculation of an aggregate rate-based standard of performance as well as in an aggregate compliance demonstration of a rate-based standard of performance.

Comment: Commenters supported the use of rate-based averaging on the grounds that it can provide operational flexibility to affected EGUs as well as the opportunity for owners and operators to optimize control technology investments. Many commenters supported averaging at the facility- and owner/operator-level as well as on a statewide or interstate basis.

Response: The EPA believes that rate-based trading can provide some additional operational flexibility and is finalizing that rate-based averaging is permissible at the facility- and owner/operator-level for affected EGUs in the medium- and long-term coal-fired subcategories. However, for reasons discussed above, the EPA believes that rate-based trading, rather than rate-based averaging, should be implemented where a state would like to implement a rate-based compliance flexibility at a state or interstate basis.

3. Rate-Based Emission Trading

The EPA proposed to permit states to incorporate rate-based trading into their state plans under these emission guidelines. In general, a rate-based trading program allows affected EGUs to trade compliance instruments that are generated based on their emission performance. A description of and responses to comments on rate-based trading can be found at the end of this subsection.

The EPA notes that, like rate-based averaging, rate-based trading can provide some flexibility for owners or operators to target cost effective reductions at specific affected EGUs, but can heighten the flexibility relative to averaging by further increasing the number of participating affected EGUs. In addition, emission trading can provide incentive for overperformance.

The proposed emission guidelines described how rate-based trading could work in this context. First, the EPA discussed how it expects states to denote the tradable compliance instrument in a rate-based trading programs as one ton of CO_2. A tradable compliance instrument denominated in another unit of measure, such as a MWh, is not fungible in the context of a rate-based emission trading program. A compliance instrument denominated in MWh that is awarded to one affected EGU most likely does not represent an equivalent amount of emissions credit when used by another affected EGU to demonstrate compliance, as the CO_2 emission rates (lb CO_2/MWh) of the two affected EGUs are likely to differ.

Each affected EGU is required under these emission guidelines to have a particular standard of performance, based on the degree of emission limitation achievable through application of the BSER, with which it would have to demonstrate compliance. Under a rate-based trading program, affected EGUs performing at a CO_2 emission rate below their standard of performance would be awarded compliance instruments at the end of each calendar year denominated in tons of CO_2. The number of compliance instruments awarded would be equal to the difference between their standard of performance CO_2 emission rate and their actual reported CO_2 emission rate multiplied by their gross generation in MWh. Affected EGUs demonstrating compliance through a rate-based averaging program that are performing worse than their standard of performance would be required to obtain and surrender an appropriate number of compliance instruments when demonstrating compliance, such that their demonstrated CO_2 emission rate is equivalent to their rate-based standard of performance. Transfer and use of these compliance instruments would be accounted for in the numerator (sum of total annual CO_2 emissions) of the CO_2 emission rate as each affected EGU performs its compliance demonstration. Compliance would be demonstrated for an affected EGU based on its reported CO_2 emission performance (in lb CO_2/MWh) and, if necessary, the surrender of an appropriate number of tradable compliance instruments, such that the demonstrated lb CO_2/MWh emission performance is equivalent to (or lower than) the rate-based standard of performance for the affected EGU.

The EPA is finalizing a determination that rate-based trading is permissible for affected EGUs in the medium- and long-term coal-fired subcategories. The Agency notes, as previously discussed, that rate-based trading (rather than averaging) must be utilized if the state wishes to establish a statewide or interstate rate-based compliance flexibility, in order to ensure compliance and equivalent stringency. For similar reasons, rate-based trading should also be utilized in lieu of owner/operator-level averaging when an owner/operator wishes to use a rate-based compliance flexibility for a group of its units that are located in more than one state.

Demonstrating equivalence with unit-specific implementation of rate-based standards of performance in a rate-based trading program is relatively straightforward. States would need to specify in their plans the affected EGUs participating in the trading program and their individual standards of performance. Under the method of rate-based trading described in this section, a compliance demonstration would be done for each participating affected EGU based on a combination of the reported emission performance and, if relevant, the surrender of compliance instruments. In addition, the EPA is requiring that the compliance instrument be denominated as one ton of CO_2 (rather than another unit such as MWh). The Agency believes this requirement is necessary to ensure an equivalent level of emission reduction as application of individual rate-based standards of performance.

An additional aspect of demonstrating equivalence is ensuring that the program achieves and maintains an equivalent level of emission reduction with standards of performance over time, which is much more certain in a rate-based trading program than in a mass-based program. Unlike mass-based trading programs, under which states must make assumptions about units' future utilization that may become inaccurate as those units' operations shift over time, rate-based trading programs do not rely on utilization assumptions. Utilization is already accounted for by default in a rate-based trading program. Thus, while mass-based compliance flexibilities require additional design features to ensure the continued accuracy of assumptions about utilization and thus emission limits or budgets over time, such features are not necessary in a rate-based trading program.

Comment: While commenters broadly supported the use of rate-based emission trading under these emission guidelines, as it provides operational flexibility to affected EGUs, some commenters expressed concern that rate-based trading could lead to an absolute increase in emissions.

Response: The EPA notes that, as a general matter, CAA section 111 reduces emissions of dangerous air pollutants by requiring affected sources to operate more cleanly. Under the construct of these emission guidelines, so long as a rate-based trading program is appropriately designed to maintain the level of emission reduction that would be achieved through unit-specific, rate-based standards of performance, it would be consistent with CAA section 111.

4. Unit-Specific Mass-Based Compliance

Although the EPA discussed mass-based trading in the proposed emission guidelines, it did not specifically address whether states may include a related flexibility, unit-specific mass-based compliance, in their plans. Several commenters supported mass-based mechanisms, including both unit-specific mass-based compliance and mass-based trading. A description of and responses to comments on unit-specific mass-based compliance can be found at the end of this subsection.

The EPA's CAA section 111 implementing regulations generally permit states to include mass-based limits in their plans, see 40 CFR 60.21a(f), subject to the requirement that standards of performance must be no less stringent than the presumptive standards of performance in the corresponding emission guidelines. 40 CFR 60.24a(c). However, the EPA has significant concerns about the use of unit-specific mass-based compliance in the context of these emission guidelines and the ability of states using this mechanism to ensure that such use will result in the same level of emission reduction that would be achieved by applying the rate-based standard of performance. These concerns arise both from the particular focus of these emission guidelines on emission reduction strategies that result in cleaner performance of affected EGUs, and the inherent uncertainty in predicting the utilization of affected EGUs during the compliance period, especially given the long lead times provided.

Therefore, while the EPA is allowing states to include unit-specific mass-based compliance in their plans for affected coal-fired EGUs in the medium- and long-term subcategories, it is also requiring states to use a backstop emission rate in conjunction with the mass-based compliance demonstration. As discussed in section X.D.1 of this preamble, the EPA believes the use of a backstop rate is consistent with the focus on achieving cleaner performance. CAA section 111 requires the mitigation of dangerous air pollution, which is generally achieved under this provision by requiring affected sources to operate more cleanly. Thus, standards of performance are typically expressed as a rate. In these emission guidelines, in particular, the BSERs for affected EGUs are control technologies and other systems of emission reduction that reduce the amount of CO_2 emitted per unit of electricity generation. The EPA is not precluding states from translating those unit-specific rate-based standards of performance into a mass-based limit (for unit-specific mass-based compliance) or budget (for emission trading). However, in order to ensure that the emission reductions required under CAA section 111 are achieved, mass-based limits or budgets must be accompanied by a backstop rate for purposes of demonstrating compliance. In addition, for coal-fired EGUs in the medium-term coal-fired subcategory in particular, it is critical that states' assumptions about future utilization do not result in inaccurate mass-based limits or budgets that allow units to emit more than they would be permitted to under unit-specific, rate-based compliance.

The EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach for affected EGUs in the long-term coal-fired subcategory, including a methodology for the applicable backstop rate, but is not finalizing a presumptively approvable approach for affected EGUs in the medium-term coal-fired subcategory. As explained below, the EPA has not been able to determine a unit-specific mass-based compliance mechanism for medium-term coal-fired EGUs that would ensure that the mass limit is no less stringent than the presumptive standard of performance under these emission guidelines.

In general, unit-specific mass-based compliance establishes a budget of allowable mass emissions (a mass limit) for an individual affected EGU based on the degree of emission limitation defined by its subcategory and a specified level of anticipated utilization. Standards of performance would be provided in the form of mass limits in tons of CO_2 for each individual affected EGU, and compliance would be demonstrated through surrender of allowances, with each allowance representing a permit to emit one ton of CO_2. Unlike mass-based emission trading, under a unit-specific mass compliance mechanism, these allowances would not be tradable with other affected EGUs. To demonstrate compliance, the affected EGU would be required to surrender allowances in a number equal to its reported CO_2 emissions during each compliance period.

As detailed in section VII.C.1.a.i(B)(7), for affected coal-fired EGUs in the long-term subcategory that are installing CCS, considering the potential impacts of variable load, startups, and shutdowns, 90 percent CO_2 capture is, in general, achievable over the course of a year. However, the EPA believes unit-specific mass-based compliance could provide some benefit by affording long-term affected coal-fired EGUs that adopt this mechanism even greater operational flexibility.[948] For example, if an affected EGU encounters challenges related to the start-up of the CCS technology or needs to conduct maintenance of the capture equipment, unit-specific mass-based compliance would provide a path for the affected EGU to continue operating. At the same time, unit-specific mass-based compliance coupled with a backstop rate would generally ensure that units operate more cleanly and that the required level of emission reduction is achieved. As explained in more detail below, the EPA's confidence regarding the equivalent stringency of this mass-based compliance approach for units in the long-term subcategory depends on the Agency's confidence in the likely utilization of a unit that has adopted emissions controls—in this case, CCS.

For affected EGUs in the long-term coal-fired subcategory, the EPA is providing a presumptively approvable approach to unit-specific mass-based compliance. To establish the presumptively approvable mass limit, the presumptively approvable rate (as described in section X.C.1.b.i of this preamble) would be multiplied by a level of gross generation (*i.e.,* utilization level) corresponding to an annual capacity factor of 80 percent, which is the capacity factor used for the BSER analysis (see section VII.C.1.a.ii of this preamble) and represents expected utilization based on the incentive provided by the IRC section 45Q tax credit. In addition, under this approach, affected EGUs would need to meet a backstop emission rate, expressed in lb CO_2 per MWh on a gross basis, equivalent to a reduction relative to baseline emission performance of 80 percent, on an annual calendar-year basis. The EPA believes this backstop rate represents a reasonable level of operational flexibility for affected EGUs

[948] States may also elect to include the short-term reliability mechanism described in section XII.F.3.a in their plans to address grid emergency situations.

in the long-term subcategory, and it could provide flexibility for sources to employ other technologies (*e.g.*, membrane and chilled ammonia capture technologies) that can achieve a similarly high degree of emission limitation to CCS with amine-based capture. States may deviate from this approach (however, as previously discussed, the approach must include a backstop rate) and deviations will be reviewed to ensure consistency with the statute and this rule when the EPA reviews the state plan. For example, states may wish to use an assumed utilization level of greater than 80 percent to establish a mass limit. In reviewing such an approach for reasonableness, the EPA would consider, among other things, whether an affected EGU's capacity factor has historically been greater than 80 percent for any continuous 8 quarters of data. The EPA would review the supporting data and resulting mass limit for consistency with the statute. The EPA has confidence that the presumptively approvable approach achieves an equivalent level of emission reduction as the implementation of the individual presumptive standard of performance because of the high degree of stringency associated with this subcategory as well as the 45Q tax credit, which incentivizes units to maximize capture of CO_2 as well as the utilization of the affected EGU.

On the other hand, the EPA does not have the same confidence in a mass-based approach to unit-specific compliance for the medium-term coal-fired subcategory for two reasons: the uncertainty in the utilization of these affected EGUs and the relatively lower stringency of the subcategory (*i.e.*, 16 percent reduction relative to baseline emission performance), particularly as compared to the long-term subcategory. The EPA has not been able to develop a workable approach to mass-based compliance for these units that both preserves the stringency of the presumptive standard of performance and results in an implementable program for affected EGUs.

First, there are significant challenges in selecting an appropriate utilization assumption for the purposes of generating a mass limit for affected EGUs in the medium-term subcategory. When setting the mass limit for a future time period, as would occur in a state plan under these emission guidelines, assumptions about the source's anticipated level of utilization must be made. Estimating future utilization of affected EGUs in the medium-term subcategory is subject to a significant degree of uncertainty, driven by sector-wide factors including changes in relative fuel prices, new incentives for technology deployment provided by the IIJA and the IRA, and increasing electrification, as well as EGU-specific factors related to its age and/or operating characteristics. As described in the *Power Sector Trends* TSD, coal-fired EGUs tend to become less efficient as they age, which may impact utilities' investment decisions and the utilization of these EGUs. In addition, affected EGUs in this subcategory are unlikely to be earning the IRC section 45Q tax credit, meaning they lack an incentive to maximize both utilization and control of emissions beyond what is required by the subcategory.

The accuracy of this estimate of utilization is critical to maintaining the environmental integrity established by unit-specific, rate-based compliance under these emission guidelines. If a state assumes a level of utilization that is higher than an affected EGU actually operates during the compliance period, the resulting mass limit will be non-binding, *i.e.*, may not reflect any emission reductions relative to what the unit would have emitted in the absence of these emission guidelines. In this case a backstop emission rate helps, but the unit would become subject to a de facto less-stringent standard of performance. This result does not preserve environmental integrity consistent with CAA section 111(a)(1). Conversely, assuming a level of utilization for the purpose of setting a mass limit that is lower than an affected EGU actually operates during the compliance period maintains the level of emission reduction of unit-specific, rate-based implementation but may have unintended effects on operational flexibility. Thus, the EPA believes that in many, if not most circumstances it will not be possible for states to accurately predict the future utilization of medium-term affected EGUs.

Second, the EPA notes that the relatively lower stringency of the subcategory further complicates the calculation of an appropriate mass limit. Under mass-based compliance, the quantity of emission reductions that corresponds to a 16 percent reduction in CO_2 emission rate is a relatively small reduction in terms of tons of CO_2. This relatively small reduction is likely to be subsumed by the uncertainty inherent in predicting the utilization of an affected EGU for purposes of determining its mass limit. That is, an EGU in the medium-term subcategory that assumes future utilization consistent with its historical baseline but reduces its emission rate by 16 percent would achieve, on paper at least, an emission reduction of 16 percent. However, if its utilization during the compliance period is more than 16 percent lower than it was in the past, the EGU using a mass-based compliance approach would face a reduced or completely eliminated obligation to improve its emission performance. In this case, mass-based compliance results in a lower level of emission reduction than unit-specific rate-based compliance. While this phenomenon is not likely to occur for long-term coal-fired affected EGUs given the much higher degree of stringency of the rate-based emission limitation and the greater certainty in future utilization, the EPA believes it would be widespread amongst medium-term affected EGUs.

Thus, the EPA is not providing a presumptively approvable approach for unit-specific mass-based compliance for affected EGUs in the medium-term coal-fired subcategory. However, it is also not prohibiting states from, in their discretion, allowing the use of unit-specific mass-based compliance. For such use to be approvable in state plans it must meet two requirements. First, as previously noted in section X.D.1 of this preamble, the state must apply a backstop rate in conjunction with a mass limit for the purposes of demonstrating compliance. As a starting point, states could consider basing their backstop rate for medium-term affected EGUs on the percentage reduction from the degree of emission limitation used for the presumptively approvable backstop rate for the long-term coal-fired subcategory, *i.e.*, the 80 percent reduction relative to baseline emission performance is approximately 90.5 percent of the 88.4 percent degree of emission limitation. Applying that to the degree of emission limitation for the medium-term coal-fired subcategory is 14.5 percent, so the backstop rate, expressed in lb CO_2 per MWh on a gross basis, could be set as a 14.5 percent reduction relative to baseline emission performance on an annual calendar-year basis. Second, as described in section X.D.1 of this preamble, states must demonstrate that their plan would achieve an equivalent level of emission reduction as the application of unit-specific, rate-based standards of performance, including showing how the mass limit has been calculated and the basis for any assumptions made (*e.g.*, about utilization). As explained in this section, the EPA believes it will be very difficult for states to accurately predict the future utilization of these units, which substantially increases the risk of establishing a mass limit that does not ensure at least an equivalent level of emission reduction. The EPA will therefore apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs employing this flexibility in state plans. Only state plans that demonstrate that use of compliance flexibilities will not erode the emission reductions required under these emission guidelines are approvable.

Comment: Commenters were generally supportive of the use of mass-based compliance mechanisms (both unit-specific and aggregate mechanisms such as emission trading) for these emission guidelines. Commenters said that mass-based compliance can help ensure environmental outcomes while also allowing sources to cycle, incorporate variable resources, and respond to grid conditions.

Response: The EPA is finalizing that mass-based compliance mechanisms are permissible when they assure an equivalent level of emission reduction with each source individually achieving its standard of performance, subject to the parameters described by the EPA in this preamble. For unit-specific mass-based compliance, affected EGUs in the medium- and long-term coal-fired subcategories may demonstrate compliance with their standards of performance through a mass limit. The EPA believes unit-specific mass-based compliance may offer some additional operational flexibility to states and affected EGUs, which could include allowing for cycling and incorporating variable resources. The EPA notes that sources must still be in compliance with the requisite backstop rate.

Comment: Many commenters expressed support for mass-based compliance mechanisms on the grounds that it facilitates calibration with existing state programs affecting the same sources that are affected under these emission guidelines.

Response: The EPA acknowledges that states may find it more straightforward to compare emission reduction obligations under these emission guidelines and existing state programs by using mass-based compliance mechanisms for state plans under these emission guidelines. However, the EPA notes that mass-based compliance mechanisms, including unit-specific mass-based compliance, are only available to certain sources affected by these emission guidelines, as described in this section of the preamble, which may be a smaller universe of sources than are affected by existing state programs. State plans must ensure an equivalent level of emission reduction from the sources that are affected sources under these emission guidelines. That is, states cannot rely on or account for emission reductions occurring at non-affected sources.

Section X.D.8 of this preamble discusses more considerations related to the relationship between the inclusion of compliance flexibilities in state plans under these emission guidelines and existing state programs.

Comment: Many commenters requested presumptively approvable mass-based standards of performance.

Response: As discussed above, the EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach for units in the long-term coal-fired subcategory that includes a backstop rate to ensure an equivalent level of emission reduction. The EPA emphasizes that states should take into account the discussions of stringency in section X.B and of demonstrating equivalence in section X.D.1 of this document, as well as guidance in each subsection on particular compliance flexibilities in considering mass-based compliance approaches that deviate from the presumptively approvable method or for sources for which the EPA is not providing a presumptively approvable approach.

5. Mass-Based Emission Trading

The EPA proposed that states would be permitted to incorporate mass-based trading into their state plans under these emission guidelines. While several commenters supported the use of mass-based emission trading, as with unit-specific mass-based compliance, the EPA has significant concerns about states' ability using this mechanism to maintain an equivalent level of emission reduction to unit-specific, rate-based standards of performance. A description of and responses to comments on mass-based trading can be found at the end of this subsection.

Under these final emission guidelines, the EPA is allowing states to include mass-based emission trading for affected coal-fired EGUs in the medium- and long-term subcategories in their plans. The same requirements and caveats discussed in section X.D.4 of this preamble above apply to the respective subcategories as for unit-specific mass-based compliance. Specifically, the EPA is requiring the use of a unit-specific backstop rate in conjunction with the mass-based compliance demonstration, which is necessary for consistency with the purpose of these emission guidelines to achieve the emission reductions required under CAA section 111(a)(1) through cleaner emission performance. The Agency similarly believes it will be very difficult for states to design mass-based trading programs that include affected EGUs in the medium-term coal-fired subcategory and that maintain the level of emission reduction that would be achieved under unit-specific compliance with the presumptive standards of performance.

In general, a mass-based trading program establishes a budget of allowable mass emissions for a group of affected EGUs, with tradable instruments (typically referred to as "allowances") issued to affected EGUs in the amount equivalent to the mass emission budget. To establish a mass budget under these emission guidelines, states would use the rate-based standard of performance and an assumed level of utilization for each participating affected EGU, and sum the resulting individual mass limits to an aggregate mass budget. Additionally, states would need to specify in the plan how allowances would be distributed to participating affected EGUs. Each allowance would represent a tradable permit to emit one ton of CO_2, with affected EGUs required to surrender allowances at the end of the compliance period in a number determined by their reported CO_2 emissions. Total emissions from all participating affected EGUs should be no greater than the total mass budget. In addition, each participating affected EGU would need to demonstrate compliance with the unit-specific backstop rate.

The EPA sees similar potential benefits related to operational flexibility of mass-based emission trading as with unit-specific mass-based compliance, discussed in section X.D.4 of this preamble. These benefits could be heightened by having a larger pool of allowances available to affected EGUs. In addition, the EPA notes that emission trading can provide incentive for overperformance.

While there is indeed the potential for heightened benefits from mass-based emission trading due to a larger pool of allowances resulting from the inclusion of multiple sources, the EPA believes that there is also a heightened risk that the mass budget will not be appropriately calculated due to the compounding uncertainty resulting from multiple participating sources. As noted in section X.D.4 of this preamble, projecting the utilization of affected EGUs has become increasingly challenging, driven by changes in technology, fuel prices, and electricity demand. In generating a mass budget, assumptions about utilization must be made for each participating source, which magnifies the risk, particularly for affected EGUs in the medium-term coal-fired subcategory, that an improper assumption about utilization for one affected EGU implicates the compliance obligation of other affected EGUs. Based on the understanding that a trading program that ensures the level of emission reduction of unit-specific, rate-based compliance under these emission guidelines would necessarily have to be designed with highly conservative utilization assumptions, the EPA is not providing a presumptively approvable approach for mass-based trading. The EPA additionally does not believe a presumptively approvable mass-based trading approach is warranted because, as noted in the introduction to this section, there are fewer sources covered by the final emission guidelines than the proposed emission guidelines, which may limit interest in and the utility of the use of mass-based trading for these emission guidelines.

The EPA is not prohibiting states from developing their own approaches to mass-based trading under these emission guidelines; however, they must apply a unit-specific backstop rate for all participating affected EGUs (see section X.D.4 of this preamble for a discussion of the backstop rate under unit-specific mass-based compliance), and they must demonstrate, as described in section X.D.1 of this preamble, that their plan would achieve an equivalent level of emission reduction as the application of individual rate-based standards of performance, including showing how the mass limit has been calculated and the basis for any assumptions made (*e.g.*, about utilization). As with unit-specific mass-based compliance, the EPA will apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs participating in a mass-based trading program in state plans. States must also specify the structure and purpose of any other trading program design feature(s) (*e.g.*, mass budget adjustment mechanism) and how they impact the demonstration of an equivalent level of emission reduction.

Comment: Many commenters supported the use of mass-based trading under these emission guidelines. Commenters stated that because many states are familiar with the mechanism, having used it for other pollutants in this sector or, in the case of some existing state programs, for CO_2, it would be easy to employ in the context of these emission guidelines and provide needed flexibility. In addition, commenters cited ensuring reliability as a motivation for using mass-based trading.

Response: While the EPA is finalizing that mass-based trading is permissible under these emission guidelines for affected EGUs in the medium- and long-term coal-fired subcategories, the EPA believes that some of the flexibility desired by commenters is addressed by other features of and changes made to the final emission guidelines, as described in the beginning of section X.D of this preamble. Despite familiarity on the part of states and sources with mass-based trading programs, the EPA is concerned that the unique circumstances of the EGUs affected by these final emission guidelines, including uncertainty over their future utilization as well as the relatively lower stringency of the medium-term coal-fired subcategory, pose a challenge for states in demonstrating an equivalent level of emission reduction of mass-based trading programs to the application of individual rate-based standards.

Comment: Some commenters expressed concern with whether and how mass-based trading would achieve and sustain the emission performance identified in the determination of BSER.

Response: The EPA shares these concerns, and for that reason is requiring the use of a unit-specific backstop rate in conjunction with mass-based compliance flexibilities, including mass-based trading. The EPA has also described its concerns over states' ability to estimate future utilization and will thus apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs participating in mass-based trading in state plans.

6. General Emission Trading and Averaging Program Implementation Features

As noted in the proposed emission guidelines, states would need to establish the procedures and systems necessary to implement and enforce an emission averaging or trading program, whether it is rate-based or mass-based, if they elect to incorporate such flexibilities into their state plans. This would include, but is not limited to, establishing the mechanics for demonstrating compliance under the program (*e.g.*, surrender of compliance instruments as necessary based on monitoring and reporting of CO_2 emissions and generation); establishing requirements for continuous monitoring and reporting of CO_2 emissions and generation; and developing a tracking system for tradable compliance instruments. The EPA requested comment on whether there was interest in capitalizing on the existing trading program infrastructure developed by the EPA for other trading programs, and some states and one utility expressed support for states' ability to use EPA's allowance management system for such programs. In addition to providing such resources for regional and national emission trading and averaging programs, the EPA has also provided technical support and resources to various non-EPA state and regional emission trading programs. In the event states choose to create emission averaging or trading programs under these emission guidelines, the EPA can provide technical support for such programs, including through the use of the Agency's existing trading program infrastructure, and is available to consult with states during the plan development process about the appropriateness of using such resources, such as the EPA's allowance management system, based on the design of state programs.

States may also need to consider how to handle differing compliance dates for affected EGUs in an emission averaging or trading program, given that under these emission guidelines the date when standards of performance apply varies depending on the subcategory for the affected EGU. The most straightforward way to address this, and which commenters supported, is to initially only include those sources with a compliance date of January 1, 2030, and then subsequently add sources into the program (and thus factor them into the aggregate standard of performance that must be achieved in the case of rate-based averaging or mass-based budget in the case of mass-based compliance approaches) at the start of the first year in which their standard of performance applies.

Another topic that states incorporating emission averaging or trading would need to consider is whether to provide for banking of tradable compliance instruments (hereafter referred to as ''allowance banking,'' although it is relevant for both mass-based and rate-based trading programs). Allowance banking has potential implications for a trading program's ability to maintain the requisite level of emission reduction of the standards of performance. The EPA recognizes that allowance banking—that is, permitting allowances that remain unused in one control period to be carried over for use in future control periods—may provide incentives for earlier emission reductions, promote operational flexibility and planning, and facilitate market liquidity. Many commenters supported allowing banking for these reasons. However, the

EPA has observed that unrestricted allowance banking from one control period to the next (absent provisions that adjust future control period budgets to account for banked allowances) may result in a long-term allowance surplus that has the potential to undermine a trading program's ability to ensure that, at any point in time, the affected sources are achieving the required level of emission performance. In the Good Neighbor Plan's trading program provisions, for example, the EPA implemented an annual allowance bank recalibration to prevent allowance surpluses from accumulating and adversely impacting program stringency.[949] While the requirement to include a backstop rate for mass-based compliance flexibilities can mitigate some concerns that unrestricted allowance banking will undermine the program's calibration towards achieving emission reductions through cleaner performance, the EPA urges that states considering allowing trading also consider restricting allowance banking (whether all or only a portion) in order to ensure that a program continues to be calibrated towards equivalent stringency with individual rate-based standards of performance, which several commenters did support.

Comment: Many commenters expressed the need for expanding the state plan submission timeline beyond 24 months to allow more time to design emission trading and averaging programs.

Response: As discussed in section X.E.2 of this preamble, the EPA is finalizing a 24-month state plan development timeframe. Because there are significantly fewer sources covered under the final emission guidelines and because the EPA is restricting certain subcategories from using compliance flexibilities such as emission averaging and trading and unit-specific mass-based compliance, the EPA believes 24 months is a reasonable amount of time to develop state plans, including time necessary to develop compliance flexibility approaches. Moreover, the EPA is offering a presumptively approvable approach to unit-specific mass-based compliance for affected EGUs in the long-term coal-fired subcategory, which can further simplify the process for developing compliance approaches in state plans.

7. Interstate Emission Trading

In the proposed emission guidelines, the EPA requested comment on whether, and under what circumstances or conditions, to allow interstate emission trading under these emission guidelines. Given the interconnectedness of the power sector and given that many utilities and power generators operate in multiple states, interstate emission trading may increase compliance flexibility. The EPA also took comment on whether the scope of rate-based averaging should be limited to a certain level of geographic aggregation (*i.e.*, intrastate but not interstate).

Many commenters expressed support for interstate trading and averaging, arguing that it further augments the flexibility offered by these mechanisms. Because electricity markets are often operated on an interstate basis, commenters stated that interstate trading and averaging would facilitate better electricity market planning. In particular, some commenters noted that interstate programs would also allow for better grid reliability planning across areas with regional planning entities.

While the EPA is finalizing a determination that states can incorporate both rate- and mass-based interstate emission trading programs into their state plans, the EPA has significant stringency-related and logistical concerns about the use of interstate emission trading for these particular emission guidelines. For mass-based trading in particular, the EPA has concerns that further increasing the number of sources participating in the program heightens the risk that the mass budget will not be appropriately calculated due to the uncertainty in estimating future utilization of affected EGUs, thus inhibiting the ability of states to demonstrate that their program achieves an equivalent level of emission reduction. This concern is somewhat alleviated for rate-based compliance flexibilities, but the EPA notes that states that wish to implement such flexibilities on an interstate basis should do so through rate-based trading, as discussed in section X.D.2. Interstate trading programs must adhere to the same requirements described in section X.D.1 and must demonstrate equivalence of the program for all participating affected EGUs.

For interstate emission trading programs to function successfully, all participating states would need to, at a minimum, use the same form of trading and have consistent design elements and identical trading program requirements. Each state participating in an interstate trading program would need to submit their own individual state plan, subject to the state plan component and submission requirements described in section X.E, but the states would coordinate their individual plan provisions addressing the interstate trading program. Additionally, each state plan would need provisions to ensure that affected EGUs within their state are in compliance taking into account the actions of affected EGUs participating in the interstate trading program in other states. The EPA would need all state plan submissions that incorporate interstate emission trading before evaluating any of the individual state plans in order to ensure consistency among all participating states. The EPA is willing to provide technical assistance to states during the state plan development process about the use of interstate emission trading, but notes that states may need to coordinate their individual state plan submissions among different EPA regions.

8. Relationship to Existing State Programs

As described in the proposed emission guidelines, the EPA recognizes that many states have adopted policies and programs (with both a supply-side and demand-side focus) under their own authorities that have significantly reduced CO_2 emissions from EGUs, that these policies will continue to achieve future emission reductions, and that states may continue to adopt new power sector policies addressing CO_2 emissions. States have exercised their power sector authorities for a variety of purposes, including economic development, energy supply and resilience goals, conventional and GHG pollution reduction, and generating allowance proceeds for investments in communities disproportionately impacted by environmental harms. The scope and approach of the EPA's final emission guidelines differ significantly from the range of policies and programs employed by states to reduce power sector CO_2 emissions, and these emission guidelines operate more narrowly to improve the CO_2 emission performance of a subset of EGUs within the broader electric power sector.

Several commenters requested guidance on how states can count existing state programs, many of which include requirements to reduce CO_2 emissions at sources not affected by this

[949] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 FR 36654 (June 5, 2023). Under the allowance bank recalibration provisions, EPA will recalibrate the "Group 3" allowance bank for the 2024–2029 control periods to meet the target bank level of 21 percent of the sum of the state emission budgets for that control period. For control periods 2030 and later, the target bank level is 10.5 percent of the sum of the state emission budgets. If the overall bank is less than the target bank level for a given control period, then no bank recalibration will occur for that control period.

rule, in their state plans under these emission guidelines. The EPA is not providing such guidance in this action but would be open to consulting with states during the state plan development process about the requirements of these emission guidelines in relation to existing state programs. States may make determinations about whether and how to design their plans, accounting for state-specific programs or requirements that apply to the same affected EGUs included in a state plan. However, as noted in section X.B, emission reductions from sources not affected by this rule cannot be used to demonstrate compliance with a standard of performance established to meet the emission guidelines. Only emission reductions at affected EGUs may count towards compliance with the state plan, including towards demonstrating compliance with the equivalent stringency criterion applied to compliance flexibilities. States may employ compliance flexibilities (such as mass-based mechanisms) described in this section in order to facilitate comparison between the requirements under existing state programs and under these emission guidelines; however, the EPA emphasizes that individual affected EGUs or groups of affected EGUs must comply with the requirements established for such units in the state plan, and that such compliance cannot incorporate measures taken by EGUs not affected by these emission guidelines.

E. State Plan Components and Submission

This section describes the requirements for the contents of state plans and the timing of state plan submissions as well as the EPA's review of and action on state plan submissions. This section also discusses issues related to the applicability of a Federal plan and timing for the promulgation of any Federal Plan, if necessary.

As explained earlier in this preamble, the requirements of 40 CFR part 60, subpart Ba, govern state plan submissions under these emission guidelines. Where the EPA is finalizing requirements that add to, supersede, or otherwise vary from the requirements of subpart Ba for the purposes of state plan submissions under these particular emission guidelines,[950] those requirements are addressed explicitly in section X.E.1.b on specific state plan requirements and in other parts of section X of this preamble. Unless expressly amended or superseded in these final emission guidelines, the provisions of subpart Ba apply.

1. Components of a State Plan Submission

A state plan must include a number of discrete components, including but not limited to those that apply for all state plans pursuant to 40 CFR part 60, subpart Ba. In this action, the EPA is also finalizing additional plan components that are specific to state plans submitted pursuant to these emission guidelines. For example, the EPA is finalizing plan components that are necessary to implement and enforce the specific types of standards of performance for affected EGUs that would be adopted by a state and incorporated into its state plan.

a. General Components

The CAA section 111 implementing regulations at 40 CFR part 60, subpart Ba, provide separate lists of administrative and technical criteria that must be met in order for a state plan submission to be deemed complete.[951] The complete list of applicable administrative completeness criteria for state plan submissions is: (1) A formal letter of submittal from the Governor or the Governor's designee requesting EPA approval of the plan or revision thereof; (2) Evidence that the state has adopted the plan in the state code or body of regulations; or issued the permit, order, or consent agreement (hereafter "document") in final form. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date; (3) Evidence that the state has the necessary legal authority under state law to adopt and implement the plan; (4) A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan, including indication of the changes made (such as redline/strikethrough) to the existing approved plan, where applicable. The submittal must be a copy of the official state regulation or document signed, stamped, and dated by the appropriate state official indicating that it is fully enforceable by the state. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. If the regulation/document provided by the state for approval and incorporation by reference into the plan is a copy of an existing publication, the state submission should, whenever possible, include a copy of the publication cover page and table of contents; (5) Evidence that the state followed all applicable procedural requirements of the state's regulations, laws, and constitution in conducting and completing the adoption/issuance of the plan; (6) Evidence that public notice was given of the plan or plan revisions with procedures consistent with the requirements of 40 CFR 60.23a, including the date of publication of such notice; (7) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23a; (8) Compilation of public comments and the state's response thereto; and (9) Documentation of meaningful engagement, including a list of pertinent stakeholders, a summary of the engagement conducted, a summary of stakeholder input received, and a description of how stakeholder input was considered in the development of the plan or plan revisions.

Pursuant to subpart Ba, the technical criteria that all plans must meet include the following: (1) Description of the plan approach and geographic scope; (2) Identification of each designated facility (*i.e.,* affected EGU); identification of standards of performance for each affected EGU; and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility; (3) Identification of compliance schedules and/or increments of progress; (4) Demonstration that the state plan submission is projected to achieve emission performance under the applicable emission guidelines; (5) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and (6) Demonstration that each standard is quantifiable, permanent, verifiable, enforceable, and nonduplicative.

b. Specific State Plan Requirements for These Emission Guidelines

To ensure that state plans submitted pursuant to these emission guidelines are consistent with the statutory requirements and the requirements of subpart Ba, the EPA is finalizing additional regulatory requirements that state plans must meet for all affected EGUs subject to a standard of performance, as well as certain subcategory-specific requirements. The EPA reiterates that standards of performance for affected EGUs included in a state plan must be quantifiable,

[950] 40 CFR 60.20a(a)(1).

[951] 40 CFR 60.27a(g)(2) and (3).

verifiable, permanent, enforceable, and non-duplicative. Additionally, per CAA section 302(l), standards of performance must be continuous in nature. Additional state plan requirements finalized as part of this action include:

• Identification of each affected EGU and the subcategory to which each affected EGU is assigned;

• A requirement that state plans include, in the regulatory portion of the plan, a list of coal-fired steam-generating EGUs that are existing sources at the time of state plan submission and that plan to permanently cease operation before January 1, 2032, and the calendar dates by which they have committed to do so. The state plan must provide that an EGU operating past the date listed in the plan is no longer exempt from these emission guidelines and is in violation of that plan, except to the extent the existing coal-fired steam generating EGU has received a time-limited extension of its date for ceasing operation pursuant to the reliability assurance mechanism described in section XII.F.3.b of this preamble;

• Standards of performance for each affected EGU, including provisions for implementation and enforcement of such standards as well as identification of the control technology or other system of emission reduction affected EGUs intend to implement to achieve the standards of performance. Standards of performance must be expressed in lb CO_2/MWh gross basis or, for affected EGUs in the low load natural gas- and oil-fired subcategory, lb CO_2/MMBtu, or, if a state is allowing the use of mass-based compliance, tons CO_2 per year;

• For each affected EGU, identification of baseline emission performance, including CO_2 mass and electricity generation data or, for affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, heat input data from 40 CFR part 75 reporting for the 5-year period immediately prior to the date this final rule is published in the **Federal Register** and what continuous 8-quarter period from the 5-year period was used to calculate baseline emission performance;

• Where a state plan provides for the use of a compliance flexibility, such as an alternative form of the standard (*e.g.*, mass limit; aggregate emission rate limitation) and/or the use of emission averaging or trading, identification of the presumptive unit-specific rate-based standard of performance in lb CO_2/MWh-gross that would apply for each affected EGU in the absence of the compliance flexibility mechanism; the standard of performance (aggregate emission rate limitation, mass limit, or mass budget) that is actually applied for affected EGUs under the compliance flexibility mechanism and how it is calculated; provisions for the implementation and enforcement of the compliance flexibility mechanism, which includes provisions that address assurance of achievement of equivalent emission reduction, including, for mass-based compliance flexibilities, identification of the unit-specific backstop emission limitation; and a demonstration that the state plan will achieve an equivalent level of emission reduction with individual rate-based standards of performance through incorporation of the compliance flexibility mechanism;

• Increments of progress and reporting obligations and milestones as required for affected EGUs within the applicable subcategories or pursuant to consideration of RULOF, included as enforceable elements of a state plan;

• For affected EGUs in the medium-term coal-fired steam generating EGU subcategory and affected EGUs relying on a plan to permanently cease operation for application of a less stringent standard of performance pursuant to RULOF, the state plan must include an enforceable commitment to permanently cease operation by a date certain. The state plan must clearly identify the calendar dates by which such affected EGUs have committed to permanently cease operation;[952]

• A requirement that state plans provide that any existing coal-fired steam generating EGU shall operate only subject to a standard of performance pursuant to these emission guidelines or under an exemption from applicability provided under 40 CFR 60.5850b (including any time-limited extension of the date by which an EGU has committed to permanently cease operations pursuant to the reliability assurance mechanism); and

• Monitoring, reporting, and recordkeeping requirements for affected EGUs.

These final emission guidelines include requirements pertaining to the methodologies for establishing a presumptively approvable standard of performance for an affected EGU within a given subcategory. These presumptive methodologies are specified for each of the subcategories of affected EGUs in section X.C.1 of this preamble.

As discussed in sections X.C and X.D of this preamble, in order for the EPA to find a state plan "satisfactory," that plan must demonstrate that it achieves the level of emission reduction that would result if each affected source was individually achieving its presumptive standard of performance, after accounting for any application of RULOF. That is, while states have the discretion to establish the applicable standards of performance for affected sources in their state plans (including whether to allow compliance to be demonstrated through the use of compliance flexibilities), the structure and purpose of CAA section 111 require that those plans achieve an equivalent level of emission reduction as applying the EPA's presumptive standards of performance to those sources (again, after accounting for any application of RULOF).

Thus, state plans must adequately document and support the process and underlying data used to establish standards of performance pursuant to these emission guidelines. Providing such documentation is critical to the EPA's review of state plans to determine whether they are satisfactory. In particular, states must include in their plan submissions information and data related to affected EGUs' emissions and operations, including CO_2 mass emissions and corresponding electricity generation data or, for affected EGUs in either the low load natural gas-fired subcategory or the oil-fired subcategory, heat input data, from 40 CFR part 75 reporting for the 5-year period immediately prior to the date the final rule is published in the **Federal Register** and identify the period from which states and affected EGUs select 8 continuous quarters of data to determine unit-specific baselines. States must include data and documentation sufficient for the EPA to understand and replicate their calculations in applying the applicable degree of emission

[952] Consistent with CAA section 111(d)(1), state plans must include commitments to cease operation as necessary for the implementation and enforcement of standards of performance. When such commitments are the predicate for receiving a particular standard of performance, adherence to those commitments is necessary to maintain the level of emission reduction Congress required under CAA section 111(a)(1). See 40 CFR 60.24a(g) (operating conditions within the control of a designated facility that are relied on for purposes of RULOF must be included as enforceable requirements in state plans); see also, *e.g.*, "Affordable Clean Energy Rule," 84 FR 32520, 32558 (July 8, 2019) (repealed on other grounds) (requiring that retirement dates associated with standards of performance be included in state plans and become federally enforceable upon approval by the EPA); 76 FR 12651, 12660–63 (March 8, 2011) (best available retrofit technology requirements based on enforceable retirements that were made federally enforceable in state implementation plan); Guidance for Regional Haze State Implementation Plans for the Second Implementation Period at 34, EPA–457/B–19–003, August 2019 (to the extent a state replies on an enforceable shutdown date for a reasonable progress determination, that measure would need to be included in the SIP and/or be federally enforceable).

limitation to individual affected EGUs to establish their standards of performance. They must also provide any methods, assumptions, and calculations necessary for the EPA to review plans containing compliance flexibilities and to determine whether they achieve an equivalent (or better) level of emission reduction as unit-specific implementation of rate-based standards of performance. Plans must also adequately document and demonstrate the methods employed to implement and enforce the standards of performance such that the EPA can review and identify measures that assure transparent and verifiable implementation.

i. Requirements Related to Meaningful Engagement

Public engagement is a cornerstone of CAA section 111(d) state plan development. In November 2023, the EPA finalized requirements in the CAA section 111(d) implementing regulations at 40 CFR part 60 subpart Ba to ensure that that all affected members of the public, not just a particular subset, have an opportunity to participate in the state plan development process. These requirements are intended to ensure that the perspectives, priorities, and concerns of affected communities, including communities that are most affected by and vulnerable to emissions from affected EGUs as well as energy communities and energy workers that are affected by EGU operation and construction of pollution controls, are included in the process of establishing and implementing standards of performance for existing EGUs, including decisions about compliance strategies and compliance flexibilities that may be included in a state plan. The final requirements for meaningful engagement in subpart Ba are in addition to the preexisting public notice requirements under subpart Ba that apply to state plan development. This section describes the meaningful engagement requirements finalized separately in subpart Ba and provides guidance to states in the application of these requirements to the development of state plans under these emission guidelines.

The fundamental purpose of CAA section 111 is to reduce emissions from categories of stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, a key consideration in the state's development of a state plan is the potential impact of the proposed plan requirements on public health and welfare. Meaningful engagement is a corollary to the longstanding requirement for public participation, including through public hearings, in the course of state plan development under CAA section 111(d).[953] A robust and meaningful engagement process is critical to ensuring that the entire public has an opportunity to participate in the state plan development process and that states understand and consider the full range of impacts of a proposed plan on public health and welfare.

The EPA finalized the following definition of meaningful engagement in the final subpart Ba revisions in November 2023: ''timely engagement with pertinent stakeholders and/or their representatives in the plan development or plan revision process.''[954] Furthermore, the definition provides that ''[s]uch engagement should not be disproportionate in favor of certain stakeholders and should be informed by available best practices.''[955] The regulations also define pertinent stakeholders, which ''include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision.''[956] The preamble for the final revisions to subpart Ba notes that ''[i]ncreased vulnerability of communities may be attributable to, among other reasons, an accumulation of negative environmental, health, economic, or social conditions within these populations or communities, and a lack of positive conditions.''[957] Consistent with the requirements of subpart Ba, it is important for states to recognize and engage the communities most affected by and/or vulnerable to the impacts of a state plan, particularly as these communities may not have had a voice when the affected EGUs were originally constructed.

Most commenters were generally supportive of the requirement to conduct meaningful engagement. Commenters acknowledged that some states and utilities have already started to conduct meaningful engagement with stakeholders like that which is required by the final subpart Ba revisions in other policy contexts. Some commenters requested more time in the state plan development process specifically to facilitate conducting meaningful engagement (comments related to the state plan development timeline are addressed section X.E.2).

In the proposed emission guidelines, the EPA provided some information to assist states in identifying potential pertinent stakeholders. Some commenters sought more guidance from the EPA on how to identify pertinent stakeholders. The Agency is providing the following discussion of the potential impacts of the emission guidelines to assist states in identifying their pertinent stakeholders. The EPA believes that this discussion provides a starting point and expects that states will use their more targeted knowledge of state- and source-specific circumstances to hone the identification of pertinent stakeholders and conduct the necessary meaningful engagement. As acknowledged by the EPA in the final revisions to subpart Ba, ''states are highly diverse in, among other things, their local conditions, resources, and established practices of engagement,''[958] so the EPA is not finalizing any additional requirements regarding the states' identification of a pertinent stakeholders for the purposes of these emission guidelines. States should consider the unique circumstances of their state and the sources within their state, with the following discussion in mind, to tailor their meaningful engagement. In addition, the EPA notes that the preamble to the final subpart Ba revisions provides discussion of best practices related to meaningful engagement.[959]

The air pollutant of concern in these emission guidelines is defined as greenhouse gases, and the air pollution addressed is elevated concentrations of these gases in the atmosphere. These elevated concentrations result in warming temperatures and other changes to the climate system that are leading to serious and life-threatening environmental and human health impacts, including increased incidence of drought and flooding, damage to crops and disruption of associated food, fiber, and fuel production systems, increased incidence of pests, increased incidence of heat-induced illness, and impacts on water availability and water quality. The Agency therefore expects that states' pertinent stakeholders will include communities within the state that are most affected by and/or vulnerable to the impacts of climate change, including those exposed to more extreme drought, flooding, and other severe weather impacts, including extreme heat and cold (states should

[953] 40 CFR 60.23(c)–(g); 40 CFR 60.23a(c)–(h).

[954] 40 CFR 60.21a(k); 88 FR 80480, 80500 (November 17, 2023).

[955] *Id.*

[956] 40 CFR 60.21a(l); 88 FR 80480, 80500 (November 17, 2023).

[957] 88 FR 80480, 80500 (November 17, 2023).

[958] *Id.*

[959] *See id.* at 80502.

refer to section III of this preamble, on climate impacts, to further assist them in identifying their pertinent stakeholders that are impacted by the pollution at issue in these emission guidelines). Commenters were supportive of the notion that those impacted by climate change are pertinent stakeholders.

Additionally, the EPA expects that another set of pertinent stakeholders will be communities located near affected EGUs and those near pipelines. These communities may experience impacts associated with implementation of the state plan, including the construction and operation of infrastructure required under a state plan. Activities related to the construction and operation of new natural gas and CO_2 pipelines may impact individuals and communities both locally and at larger distances from affected EGUs but near any associated pipelines. Commenters were supportive of the notion that communities impacted by infrastructure development required by the state plan are pertinent stakeholders.

Because these emission guidelines address air pollution that becomes well mixed and is long-lived in the atmosphere, the collective impact of a state plan is not limited to the immediate vicinity of EGUs and any associated infrastructure. The EPA therefore expects that states will consider communities and populations within the state that are both most impacted by particular affected EGUs and associated pipelines as well as those that will be most affected by the overall stringency of state plans.

The EPA also expects that states will include the energy communities impacted by each affected EGU, including the energy workers employed at affected EGUs (including employment in operation and maintenance), workers who may construct and install pollution control technology, and workers employed in associated industries such as fuel extraction and delivery and CO_2 transport and storage, as pertinent stakeholders. These communities are impacted by power sector trends on an ongoing basis. The EPA acknowledges that a variety of Federal programs are available to support these communities and encourages states to consider these programs when conducting meaningful engagement and analyzing the impacts of compliance choices.[960] Commenters supported encouraging states to both consider these communities as part of meaningful engagement under these emission guidelines as well as to take advantage of Federal resources available for employment and training assistance, and highlighted a Colorado state law[961] requiring utilities to share workforce data and develop a workforce transition plan. The EPA supports such approaches to workforce data transparency and encourages states to provide such data in the course of meaningful engagement and the development of state plans.

The EPA also expects that states will include relevant balancing authorities, systems operators and reliability coordinators that have authority to maintain electric reliability in their jurisdiction as part of their constructive engagement under these requirements. These stakeholders are impacted by a state plan as they are the entities authorized to plan for electric reliability. Visibility into unit-specific compliance plans will help ensure those entities have adequate lead time to plan and address any potential reliability-related issues. Early notification and periodic follow up on unit-specific decisions, including control technology installation and voluntary cease operation choices and timeframes will greatly assist reliability planning authorities.

Several commenters noted the need for consideration of communities overburdened by existing air pollution issues, including both greenhouse gases and co-pollutants, as pertinent stakeholders in these emission guidelines. The Agency urges states to consider the cumulative burden of pollution when identifying their pertinent stakeholders for these emission guidelines, as these stakeholders may be especially vulnerable to the impacts of a state plan or plan revision due to "an accumulation of negative environmental . . . conditions," as defined in the final subpart Ba revisions. Many states are already implementing policies to consider cumulative impacts in overburdened communities, including California and New Jersey. It is also important to note that the EPA is "prioritizing cumulative impacts research to address the multiple stressors to which people and communities are exposed, and studying how combinations of stressors affect health, well-being, and quality of life at each developmental stage throughout the course of one's life."[962] Additionally, the EPA is in the process of developing a workplan that lays out actions the agency will take to integrate and implement cumulative impacts within the EPA's work through FY25. The EPA's commitments, as stated in the EPA's response to the OIG Report, include continuing to refine analytic techniques based on best available science, increasing the body of relevant data and knowledge, and using outcome-based metrics to measure progress, including quantifiable pollution reduction benefits in communities.[963]

The EPA recognizes that facility- and community-specific circumstances, including the exposure of overburdened communities to additional chemical and non-chemical stressors, may also exist. The meaningful engagement process is designed to allow states to identify and to enable consideration of these and other facility- and community-specific circumstances. This includes consideration of facility- and community-specific concerns with emissions control systems, including CCS. States should design meaningful engagement to elicit input from pertinent stakeholders on facility- and community-specific issues related to implementation of emissions control systems generally, as well as on any considerations for particular systems.

The EPA encourages states to consider regional implications, explore opportunities for collaboration, and to share best practices. In some cases, an affected EGU may be located near state

[960] An April 2023 report of the Federal Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Energy Communities IWG) summarizes how the Bipartisan Infrastructure Law, CHIPS and Science Act, and Inflation Reduction Act have greatly increased the amount of Federal funding relevant to meeting the needs of energy communities, as well as how the Energy Communities IWG has launched an online Clearinghouse of broadly available Federal funding opportunities relevant for meeting the needs and interests of energy communities, with information on how energy communities can access Federal dollars and obtain technical assistance to make sure these new funds can connect to local projects in their communities. Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization. "Revitalizing Energy Communities: Two-Year Report to the President" (April 2023). *https://energycommunities.gov/wp-content/uploads/2023/04/IWG-Two-Year-Report-to-the-President.pdf.*

[961] Colorado Legislature, Senate Law 19–236. *https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf.*

[962] Nicolle S. Tulve, Andrew M. Geller, Scot Hagerthey, Susan H. Julius, Emma T. Lavoie, Sarah L. Mazur, Sean J. Paul, H. Christopher Frey, Challenges and opportunities for research supporting cumulative impact assessments at the United States environmental protection agency's office of research and development, The Lancet Regional Health—Americas, Volume 30, 2024, 100666, ISSN 2667–193X, *https://doi.org/10.1016/j.lana.2023.100666.*

[963] EPA Response to Draft Office of Inspector General Report, The EPA Lacks Agencywide Policies and Guidance to Address Cumulative Impacts and Disproportionate Health Effects on Communities with Environmental Justice Concerns. *https://www.epaoig.gov/sites/default/files/reports/2023-08/_epaoig_20230822-23-p-0029.pdf.*

or Tribal borders and impact communities in neighboring states or Tribal lands. Some commenters suggested that those near state or Tribal borders may be pertinent stakeholders. The EPA agrees that it could be reasonable, in cases where EGUs are located near borders, for the state to consider identifying pertinent stakeholders in the neighboring state or Tribal land and to work with the relevant air pollution control authority of that state or Tribe to conduct meaningful engagement that addresses cross-border impacts. Some commenters supported the notion that those near state or Tribal borders may be pertinent stakeholders.

The revisions to subpart Ba in November of 2023 established requirements for demonstrating how states provided meaningful engagement with pertinent stakeholders, and these requirements apply here. According to the requirements under subpart Ba, the state will be required to describe, in its plan submittal: (1) A list of the pertinent stakeholders identified by the state; (2) a summary of engagement conducted; (3) a summary of the stakeholder input received; and (4) a description of how stakeholder input was considered in the development of the plan or plan revisions. The EPA will review the state plan to ensure that it includes these required descriptions regarding meaningful public engagement as part of its completeness evaluation of a state plan submittal. If a state plan submission does not include the required elements for notice and opportunity for public participation, including the procedural requirements at 40 CFR 60.23a(i) and 60.27a(g)(2)(ix) for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or (where a plan has become complete by operation of law) to disapprove the plan.

In approaching meaningful engagement, states should first identify their pertinent stakeholders. As previously noted, the state should allow for balanced participation, including communities most vulnerable to the impacts of the plan. Next, states should develop a strategy for engagement with the identified pertinent stakeholders. This includes ensuring that information is made available in a timely and transparent manner, with adequate and accessible notice. As part of this strategy for engagement, states should also ensure that they share information and solicit input on plan development and on any accompanying assessments or analyses. In providing transparent and adequate notice of plan development, states should consider that internet notice alone may not be appropriate for all stakeholders, given lack of access to broadband infrastructure in many communities. Thus, in addition to internet notice, examples of prominent advertisement for engagement and public hearing may include notice through newspapers, libraries, schools, hospitals, travel centers, community centers, places of worship, gas stations, convenience stores, casinos, smoke shops, Tribal Assistance for Needy Families offices, Indian Health Services, clinics, and/or other community health and social services as appropriate for the emission guideline addressed. The state should also consider any geographic, linguistic, or other barriers to participation in meaningful engagement for members of the public.

The EPA notes that several EPA resources are available to assist states and stakeholders in considering options for state plans. For example, included in the docket for this rulemaking is a unit-level proximity analysis that includes information about the population within 5 kilometers and 10 kilometers of each EGU covered by this rule. This analysis includes information about air emissions from each facility, and the potential emission implications of installing CCS. Additionally, the EPA's Power Plant Environmental Justice Screening Methodology (PPSM)[964] incorporates several peer-reviewed approaches that combine air quality modeling with environmental burden and population characteristics data to identify and connect power plants to geographic areas potentially exposed to air pollution by those power plants and to quantify the relative potential for environmental justice concern in those areas. This information provides states and stakeholders with the ability to identify the census block groups that are potentially exposed to air pollution by each EGU, including air pollutants in the vicinity of each EGU as well as pollutants that can travel significant distances. Another resource available to assist states and stakeholders is the EPA's Environmental Justice Screening and Mapping Tool (EJScreen),[965] which includes information at the census block group level about existing environmental burdens as well as socioeconomic information. Other federal resources include the Energy Communities Interagency Working Group's online Clearinghouse, which lists federal funding opportunities relevant for meeting the needs and interests of energy communities, some of which may be relevant for state plan development.

In their plan submittal, states must demonstrate evidence that they conducted meaningful engagement. In addition to a list of pertinent stakeholders and a summary of the engagement conducted, states must provide a summary of the input received and a description of how the input they received was considered in plan development. The type of information states may receive from their pertinent stakeholders could include data on the population and demographics of communities located near affected EGUs and associated pipelines; identification of and data on any overburdened communities vulnerable to the impacts of the state plan; data on the energy workers affected by anticipated compliance strategies on the part of owners and operators; data on workforce needs (*e.g.,* expected number and type of jobs created, and skills required in anticipation of compliance with the state plan); and, if relevant, data on the population and demographics of communities near state and Tribal borders that may be vulnerable to the impacts of the state plan. The EPA encourages states to include such data in their demonstration of meaningful engagement in their state plan submittal.

The EPA emphasizes to states that the meaningful engagement process is intended to include community perspectives, particularly those communities that, historically, may not have had a role in the state plan development process, in the development of standards of performance, compliance strategies, and compliance flexibilities for affected EGUs by which they are impacted.

ii. Requirements for Transparency and Compliance Assurance

The EPA proposed and requested comment on several requirements designed to help states ensure timely compliance by affected EGUs with standards of performance, as well as to assist the public in tracking affected EGUs' progress towards their compliance dates.

First, the EPA requested comment on whether to require that an affected EGU's enforceable commitment for subcategory applicability (*e.g.,* a state elects to rely on an affected coal-fired steam-generating unit's commitment to permanently cease operations before January 1, 2039, to meet the applicability requirements for the medium-term subcategory), must be in

[964] *https://www.epa.gov/power-sector/power-plant-environmental-justice-screening-methodology.*

[965] *https://www.epa.gov/ejscreen.*

the form of an emission limit of 0 lb CO_2/MWh that applies on the relevant date. Such an emission limit would be included in a state regulation, permit, order, or other acceptable legal instrument and submitted to the EPA as part of a state plan. If approved, the affected EGU would have a federally enforceable emission limit of 0 lb CO_2/MWh that would become effective as of the date that the EGU permanently ceases operations. The EPA requested comment on whether such an emission limit would have any advantages or disadvantages for compliance and enforceability relative to the alternative, which is an enforceable commitment in a state plan to cease operation by a certain date.

The EPA received few comments on this topic. One commenter,[966] in particular, did not support a specific requirement that the permit or other enforceable commitment must be in the form of an emission limit of 0 lb CO_2/MWh, claiming it seems needlessly prescriptive. This commenter also encouraged the EPA to recognize delegated or SIP-approved states' enforceable permit conditions, certifications, and voiding of authorizations, as practically enforceable.

The EPA is not finalizing a requirement that states must include commitments to permanently cease operating in state plans in the form of 0 lb CO_2/MWh emission limits. The Agency is concluding that it is within the discretion of the state to create an enforceable commitment to permanently cease operation, where applicable, in the form it deems appropriate. Such commitments may be codified in a state regulation, permit, order, or other acceptable legal instrument and submitted to the EPA as part of a state plan. It is important to note that if an emission limit or some other requirement that creates an enforceable commitment to cease operation is initially included in a title V permit before the submission of a state plan, that condition must be labeled as ''state-only'' or ''state-only enforceable'' until the EPA approves the state plan, at which point the permit should be revised to make that requirement federally enforceable. Including state instruments (such as state permits, certifications, and other authorizations) reflecting affected EGUs' intent to permanently cease operation in the state plan, when such intent is the basis of receiving a less stringent standard of performance, is necessary because state instruments can be revised without a corresponding revision to the state plan or standard of performance. This outcome—a source continuing to operate into the future with a less-stringent standard of performance that is not necessarily warranted—would undermine the integrity of these emission guidelines.

Second, the EPA proposed and is finalizing a requirement that state plans that include affected EGUs that plan to permanently cease operation must require that each such affected EGU comply with applicable state and Federal requirements for permanently ceasing operation, including removal from its respective state's air emissions inventory and amending or revoking all applicable permits to reflect the permanent shutdown status of the EGU. This requirement covers affected coal-fired steam generating EGUs in the medium-term subcategory as well as affected EGUs that are relying on a commitment to permanently cease operating to obtain a less stringent standard of performance pursuant to consideration of RULOF. This requirement merely reinforces the application of requirements under state and Federal laws that are necessary in this context for transparency and the orderly administration of these emission guidelines.

Third, the EPA proposed and is finalizing a requirement that each state plan must require owners and operators of affected EGUs to establish publicly accessible websites, referred to here as a ''Carbon Pollution Standards for EGUs website,'' to which all reporting and recordkeeping information for each affected EGU subject to the state plan would be posted, including the aforementioned information required to be submitted as part of the state plan. This information includes, but is not limited to, emissions data and other information relevant to determining compliance with applicable standards of performance, information relevant to the designation and determination of compliance with increments of progress and reporting obligations including milestones for affected EGUs that plan to permanently cease operations, and any extension requests made and granted pursuant to the compliance date extension mechanism or the reliability assurance mechanism. Although this information will also be required to be submitted directly to the EPA and the relevant state regulatory authority, both the EPA and stakeholders have an interest in ensuring that the information is made accessible in a timely manner. Some commenters agreed with these requirements. The EPA anticipates that the owners or operators of some affected EGUs may already be posting comparable reporting and recordkeeping information to publicly available websites under the EPA's April 2015 Coal Combustion Residuals Rule,[967] such that the burden of this website requirement for these units could be minimal.

Comment: Several commenters argued that this was a duplicative requirement, noting that utilities already report GHG emissions data under the Acid Rain Program and Mandatory GHG Reporting Program. Commenters also stated that this requirement would pose a burden for companies who would have to dedicate staff to maintaining the website. One commenter[968] suggested that EPA include more specific requirements related to the format of data, notification of uploads and removal of documentation, and summarization of content.

Response: The EPA disagrees that this requirement is duplicative of reporting requirements under other programs. In addition to affected EGUs having unique standards of performance and compliance schedules under these emission guidelines, these emission guidelines also include unique reporting requirements that are not covered by the programs identified by the commenters, including increments of progress and reporting on milestones. In addition, the EPA believes that this information should be made broadly available to all stakeholders in a timely manner, which is not necessarily accomplished via the programs and reporting mechanisms identified by the commenters. Accordingly, the EPA is finalizing a requirement that each state plan must require owners and operators of affected EGUs to establish publicly accessible websites and to post the relevant information described in this section. Additionally, data should be available in a readily downloadable format.

Fourth, to promote transparency and to assist the EPA and the public in assessing progress towards compliance with state plan requirements, the EPA proposed and is finalizing a requirement that state plans include a requirement that the owner or operator of each affected EGU shall report any deviation from any federally enforceable state plan increment of progress or reporting milestone within 30 business days after

[966] See Document ID No. EPA–HQ–OAR–2023–0072–0781.

[967] See *https://www.epa.gov/coalash/list-publicly-accessible-internet-sites-hosting-compliance-data-and-information-required* for a list of websites for facilities posting Coal Combustion Residuals Rule compliance information, *see also* 80 FR 21301 (April 17, 2015).

[968] See Document ID No. EPA–HQ–OAR–2023–0072–0813.

the owner or operator of the affected EGU knew or should have known of the event. That is, the owner or operator must report within 30 business days if it is behind schedule such that it has missed an increment of progress or reporting milestone. In the report, the owner or operator of the affected EGU will be required to explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. The owner or operator of the EGU must submit the report to the state regulatory agency and concurrently post the report to the affected EGU's Carbon Pollution Standards for EGUs website.

Fifth, in the proposed action, the EPA explained its general approach to exercising its enforcement authorities through administrative compliance orders (''ACOs'') to ensure compliance while addressing genuine risks to electric system reliability. The EPA solicited comment on whether to promulgate requirements in the final emission guidelines pertaining to the demonstrations, analysis, and information the owner or operator of an affected EGU would have to submit to the EPA in order to be considered for an ACO. The EPA is not finalizing the proposed approach to use ACOs to address risks to grid reliability.

Comment: One commenter argued that the conditions to qualify for an ACO would make it challenging for an EGU to obtain an ACO in instances of urgent reliability.[969] Commenters argued that there are not any guarantees that the EPA would act on such requests for an ACO in a timely manner, particularly because the EPA has not set any deadline for review and presumably would argue that any decision falls within the EPA's enforcement discretion and is not subject to judicial review. Additionally, one commenter argued that the proposal is unworkable for the purposes of addressing more immediate reliability needs, specifying that EGUs may not be able to readily obtain the information or analysis necessary for preparing documentation for the EPA from their regional entity or state.[970]

Another commenter argued that the proposed mechanism provides no relief during an energy crisis because they would be offered only after the fact to resolve any alleged violations. Therefore, the possibility of future enforcement discretion and ACOs will not help a power generator decide in the moment whether to keep running and risk a violation or shut down, risking grid reliability and affecting our customers. the commenter also stated that ACOs are enforcement actions that carry negative implications and the potential for significant civil penalties, and citizen groups are unlikely to exercise discretion similar to that of the EPA, even if the EPA decides that a low (or no) penalty is appropriate. Lastly, this commenter noted that ACOs are typically intended to resolve relatively short-term noncompliance events that can be remedied and that do not reflect a fundamental inability to comply.

Response: As discussed in section XII.F and elsewhere in this preamble, the EPA has made several adjustments and provided several mechanisms in this final rule that have the effect of or are expressly intended to provide grid operators and reliability authorities methods to address grid reliability. For example, the EPA is providing that states may include in their state plans a short-term reliability mechanism that allows affected EGUs to comply with an emission limitation corresponding to their baseline emission rate during periods of grid emergency. For further detail, see section XII.F.3.a of this preamble. This mechanism is intended to allow states to respond quickly to emergency situations, and to avoid affected EGUs being out of compliance or needing to work towards compliance through an ACO. Considering the structural changes the EPA has made in these final emission guidelines and the mechanisms it is providing states to address grid reliability, the EPA does not believe that states and affected EGUs will need to rely on ACOs to address compliance during periods of grid emergency.

Finally, as explained in section VII.B of this preamble, coal-fired steam generating EGUs that plan to permanently cease operating before January 1, 2032, are not covered by these emission guidelines, *i.e.*, they are not affected EGUs. However, to maintain the environmental integrity of these emission guidelines, it is critical that any existing sources that are operating as of January 1, 2032, are doing so subject to a requirement to operate more cleanly, and therefore essential that sources report on their actions to qualify for the exemption. As explained in the preamble to the proposed rule and section X.C.4 of this preamble, there are many steps the owners or operators of EGUs must take as they get ready to permanently cease operations and those steps vary between units and jurisdictions. Procession in a timely manner through these steps is the best indicator the EPA has of whether or not an existing source remains qualified for an exemption from these emission guidelines. Should a source's plans to cease operating change, *e.g.*, because the relevant planning authority has called on it to remain in operation for reliability or resource adequacy, the state, the public, and the EPA need to be aware of that change as soon as possible in order to appropriately address the source under these emission guidelines. The EPA therefore believes that having sources that plan to cease operation before January 1, 2032, report to the Agency on the steps they have taken towards doing so is critical to ensuring that those sources remain qualified for the exemption and thus to maintaining the environmental integrity of these emission guidelines.

The EPA is requiring existing coal-fired steam generating EGUs that are in existence as of the date of a state plan submission but plan to cease operating before January 1, 2032, to comply with certain reporting requirements pursuant to CAA section 114(a). Among other things, this provision gives the EPA authority to require recordkeeping and reporting of sources for the purpose of ''developing or assisting in the development of any implementation plan under . . . section 7411(d) of this title[or] any standard of performance under section 7411 of this title,'' ''determining whether any person is in violation of any such standard of any requirement of such a plan,'' or ''carrying out any provision of this chapter.'' Owners or operators of coal-fired steam generating EGUs that would be covered by these emission guidelines but for their plans to permanently cease operating are required to make reports necessary to ascertain whether they will in fact qualify for the exemption. This reporting obligation is necessary for preserving the integrity of the rule, and is consistent with ensuring that states develop plans that include standards of performance for all existing sources and for anticipating whether a state plan may need to be revised to include a standard of performance for an existing source that will not be eligible for an exemption from these emission guidelines.[971]

[969] See Document ID No. EPA–HQ–OAR–2023–0072–0770.

[970] *Id.*

[971] The milestone reporting requirements for affected coal-fired steam generating EGUs in the medium-term subcategory and those relying on a shorter remaining useful life for a less-stringent standard of performance pursuant to RULOF are authorized under both CAA sections 114(a) and 111(d)(1), the latter of which provides that state plans shall provide for the implementation and enforcement of standards of performance. In that

The reporting requirements the EPA is promulgating for sources that plan to permanently cease operation before January 1, 2032, are similar to the reporting requirements the Agency is requiring for medium-term coal-fired steam generating affected EGUs and affected EGUs relying on a shorter remaining useful life for a less-stringent standard of performance through RULOF. Those requirements are described in section X.C.4 of this preamble and require the definition of milestones tailored to individual units which are then embedded in periodic reporting requirements to assess progress toward the cessation of operations. However, consistent with CAA section 114, the requirements for sources that are exempt from these emission guidelines are limited to reporting and do not include the establishment of milestones. Thus, the requirements are as follows: Five years before any planned date to permanently cease operations or by the date upon which state plan is submitted, whichever is later, the owner or operator of the EGU must submit an initial report to the EPA that includes the following: (1) A summary of the process steps required for the EGU to permanently cease operation by the date included in the state plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. These process steps may include, *e.g.*, initial notice to the relevant reliability authority of the deactivation date and submittal of an official retirement filing (or equivalent filing) made to the EGU's reliability authority. (2) Supporting regulatory documents, including correspondence and official filings with the relevant regional RTO, ISO, balancing authority, PUC, or other applicable authority; any deactivation-related reliability assessments conducted by the RTO or ISO; and any filings pertaining to the EGU with the SEC or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which the plans for the EGU are mentioned; any integrated resource plans and PUC orders referring to or approving the EGU's deactivation; any reliability analyses developed by the RTO, ISO, or relevant reliability authority in response to the EGU's deactivation notification; any notification from a reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and any notification to or from an RTO, ISO, or relevant reliability authority altering the timing of deactivation for the EGU.

For each of the remaining years prior to the date by which an EGU has committed to permanently cease operations, the operator or operator of an EGU must submit an annual status report to the EPA that includes: (1) Progress on each of the process steps identified in the initial report; and (2) supporting regulatory documents, including correspondence and official filings with the relevant RTO, balancing authority, PUC, or other applicable authority to demonstrate progress toward all steps; and (3) regulatory documents, and relevant SEC filings (listed in the preceding paragraph) that have been issued, filed or received since the prior report.

The EPA is also requiring that EGUs that plan to permanently cease operation by January 1, 2032, submit a final report to the EPA no later than 6 months following its committed closure date. This report would document any actions that the unit has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

2. Timing of State Plan Submissions

The EPA proposed a state plan submission deadline that is 24 months from the date of publication of the final emission guidelines, which, at that time was 9 months longer than the default state plan submission timeline in the proposed 40 CFR part 60, subpart Ba implementing regulations. The EPA finalized subpart Ba with a default timeline of 18 months for state plan submissions, 40 CFR 60.23a(a)(1); regardless, the EPA is superseding subpart Ba's timeline under these emission guidelines and is requiring that state plans be submitted 24 months after publication of this final rule in the **Federal Register**.

As discussed in the preamble to the proposed rule,[972] these emission guidelines apply to a relatively complex source category and state plan development will require significant analysis, consultation, and coordination between states, utilities, reliability authorities, and the owners or operators of individual affected EGUs. The power sector is subject to layers of regulatory and other requirements under different authorities (*e.g.*, environmental, electric reliability, SEC) and the decisions states make under these emission guidelines will necessarily have to accommodate overlapping considerations and processes. States' plan development may have to integrate decision making by not only the relevant air agency or agencies, but also ISOs, RTOs, or other balancing authorities. While 18 months is a reasonable timeframe to accommodate state plan development for source categories that do not require this level of coordination, the EPA does not believe it is reasonable to expect states and affected EGUs to undertake the coordination and planning necessary to ensure that plans for implementing these emission guidelines are consistent with the broader needs and trajectory of the power sector within the default period provided under subpart Ba.

However, there are also notable differences between the circumstances of the proposed versus these final emission guidelines that are relevant to the state plan submission timeline. First, the EPA is not finalizing emission guidelines applicable to combustion turbine EGUs, which will significantly decrease the number of affected EGUs that states must address in their plans. Relative to proposal, there are approximately 184 fewer individual units to which these emission guidelines will apply (based on information at the time of the final rule), and the final emission guidelines do not include co-firing with low-GHG hydrogen as a BSER. The analytical and other burdens associated with state planning will thus be significantly lighter than anticipated at proposal, as states will have to address not only fewer sources but also a smaller universe of potential control strategies. Additionally, as explained in section VII.B.1 of this preamble, these final emission guidelines do not apply to existing coal-fired EGUs that plan to permanently cease operation prior to January 1, 2032. While under the proposed emission guidelines states would have had to establish standards of performance for every existing source operating as of January 1, 2030, states will be able to forgo addressing a subset of these existing sources under this final rule.

In addition to states needing to address far fewer existing sources in their state plans than anticipated under the proposed emission guidelines, it is also not expected that the owners or operators of sources will begin implementation of control strategies before state plan submission. At proposal the EPA believed that some owners or operators of affected EGUs would do feasibility and FEED studies for CCS during state plan development,

case, reporting requirements are necessary to ensure that the predicate conditions for the sources' standards of performance are satisfied.

[972] 88 FR 33240, 33402–03 (May 23, 2023).

i.e., before state plan submission. For other affected coal-fired EGUs, the EPA anticipated that owners or operators would undertake certain planning, design, and permitting steps prior to state plan submission.[973] In developing these final emission guidelines, the EPA changed its earlier assumption that states and affected EGUs would take significant steps towards planning and implementing control strategies prior to state plan submission. There are certain preliminary steps, such as an initial feasibility study, that the EPA expects that states and/or affected EGUs will undertake as a typical part of the state planning process. Under any rule or circumstances, it would not be reasonable for a state to commit an affected EGU to installation and operation of a certain control technology without undertaking at least an initial assessment of that technology—this is what is accomplished by feasibility studies. However, while the Agency believes that some sources are currently or will be undertaking FEED studies or other significant steps towards implementing pollution controls independent of these emission guidelines at earlier times, the EPA is not assuming when setting the compliance deadline that EGUs will be taking such steps prior to the existence of a state law requirement to do so (*i.e.,* prior to state plan adoption and submission).

The EPA received a number of comments on the proposed 24-month timeline for state plan submissions, which are discussed in detail below. As a general matter, many of these comments requested a longer timeframe for developing and submitting state plans. However, given that the number of affected EGUs state plans will have to cover under these final emission guidelines is very likely to be significantly lower than anticipated based on the proposal and that the EPA is not expecting states or owners or operators of affected EGUs to conduct FEED studies or otherwise start work on implementation prior to state plan submission, the EPA continues to believe that 24 months is an appropriate timeframe. Additionally, as discussed in the preamble to the recent revisions to the 40 CFR part 60, subpart Ba implementing regulations, the EPA's approach to timelines for state plan submission and review under CAA section 111(d) is informed by the need to minimize the impacts of emissions of dangerous air pollutants on public health and welfare by proceeding as expeditiously and as reasonably possible while accommodating the time needed for states to develop an effective plan.[974] To this end, the EPA is promulgating a timeframe for state plan submissions that is based on the minimum administrative time that is reasonably necessary given the need for states and owners or operators of affected EGUs to coordinate with reliability authorities in the development of state plans. In this case, the EPA believes that providing an additional 6 months beyond subpart Ba's 18 months for state plan submissions is sufficient to accommodate this additional coordination, particularly given that the number of affected EGUs that states will be addressing in their plans is far fewer than expected under the proposed emission guidelines.

Comment: Several commenters supported the EPA's proposed 24-month timeframe for state plan submissions and stressed the importance of achieving emission reductions as quickly as possible. Commenters also noted that, based on anecdotal evidence, 24 months is generally sufficient to incorporate legislative, regulatory, and other administrative procedures associates with submitting state plans. Many commenters, however, requested that the EPA provide additional time for states to develop and submit their state plans; many requested 36 months with some commenters asserting that even more time would be required. Commenters asking for a longer timeframe cited reasons including the size of states' EGU fleets and the specific BSERs proposed for certain subcategories (*i.e.,* CCS and hydrogen co-firing), the need for owners or operators of affected EGUs to conduct systems analyses and update their integrated resource plans (IRPs) prior to making final decisions for state plans, and the need for states to get their choices approved by the appropriate reliability and other regulatory commissions.

Response: As explained above, the EPA has made a number of changes in these final emission guidelines that have the effect of decreasing the planning burden on states, including not finalizing requirements for combustion turbine EGUs, exempting coal-fired EGUs that plan to cease operating by January 1, 2032, finalizing fewer subcategories for coal-fired EGUs, and not finalizing the subcategory for coal-fired EGUs that was based on utilization level. In general, these changes will decrease the number of units that state plans must address and also decrease the number and complexity of decisions states must make with regard to those units. Furthermore, 24 months is sufficient time for states to complete the steps necessary to develop and submit a state plan. Owners and operators are already or should already be considering how they will operate in a future environment where sources operating more cleanly are valued more. The EPA expects that states are already working or will work closely with the operators and operators of affected EGUs as those owners and operators update their IRPs and proceed through any necessary processes with, *e.g.,* PUCs and reliability authorities. Thus, the Agency expects that consultation with and between owners and operators, PUCs, and reliability authorities is currently ongoing and will remain so throughout state plan development and implementation. Against this backdrop of ongoing planning and consultation, the EPA's obligation in these emission guidelines is to ensure that state plan development and submission occurs within a timeframe consistent with the "adherence to [the EPA's] 2015 finding of an urgent need to counteract the threats posed by unregulated carbon dioxide emissions from coal-fired power plants."[975] The timeframe the EPA is providing for state plan development upfront coupled with the long lead times it is providing for compliance with standards of performance provides states and owners or operators ample time to ensure the orderly implementation of the control requirements under these emission guidelines.

Comment: Several commenters asserted that the EPA should provide longer than 24 months for state plan submissions to provide time for states to work through their necessary rulemaking, legislative, and/or administrative processes. Some commenters similarly stated that more than 24 months is needed in order to accommodate meaningful engagement on draft state plans.

Response: The default timeline provided for state plan development and submission under 40 CFR part 60, subpart Ba is 18 months. As the EPA acknowledged when it promulgated this timeframe, state regulatory and legislative processes and resources can vary significantly and influence the time needed to develop and submit state plans.[976] However, the CAA contains

[973] 88 FR 33240, 33402 (May 23, 2023).

[974] See, *e.g.,* 88 FR 80480, 80486 (November 17, 2023).

[975] *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914, 994 (D.C. Cir. 2021).

[976] 88 FR 80480, 80488 (November 17, 2023).

numerous, long-standing requirements under other programs for states to develop and submit plans in 18 or fewer months. The EPA therefore believes that states should be well positioned to accommodate an 18-month state plan submission timeframe, let alone at 24-month timeframe, from the perspective of the timing of state processes. The Agency does not believe it would be reasonable or consistent with CAA section 111's purpose of reducing air pollution that endangers public health and the environment to extend state plan submission deadlines to defer to lengthy state administrative processes.

Similarly, the EPA believes that 24 months provides sufficient time for states to conduct meaningful engagement with pertinent stakeholders under these emission guidelines. As discussed in section X.E.1.b.i of this preamble, the EPA is providing additional information in these final emission guidelines that states may use to inform their meaningful engagement strategies and that can help them to fulfill their obligations in a timely and diligent fashion. For example, the EPA has noted a number of types of stakeholder communities to assist states in identifying their pertinent stakeholders. It has also provided information and tools that states may use in considering options for state plans, including facility-specific information on air emissions and the potential emissions implications of installing CCS. Commenters also pointed out that several states have recently adopted regulations, programs, and tools relevant to identifying pertinent stakeholders and conducting meaningful engagement; such programs and tools, in addition to states' growing body of knowledge and experience pursuant to state initiatives and priorities, will aid states and stakeholders alike in conducting robust meaningful engagement in the timeframe for state plan development.

3. State Plan Revisions

As discussed in the preamble of the proposed action, the EPA expects that the 24-month state plan submission deadline for these emission guidelines would give states, utilities and independent power producers, and stakeholders sufficient time to determine into which subcategory each of the affected EGUs should fall and to formulate and submit a state plan accordingly. However, the EPA also acknowledges that, despite states' best efforts to accurately reflect the plans of owners or operators with regard to affected EGUs at the time of state plan submission, such plans may subsequently change. In general, states have the authority and discretion to submit revised state plans to the EPA for approval.[977] State plan revisions are generally subject to the same requirements as initial state plan submissions under these emission guidelines and the subpart Ba implementing regulations, including meaningful engagement, and the EPA reviews state plan revisions against the applicable requirements of these emission guidelines and the subpart Ba implementing regulations in the same manner in which it reviews initial state plan submissions pursuant to 40 CFR 60.27a. Requirements of the initial state plan approved by the EPA remain federally enforceable unless and until the EPA approves a plan revision that supersedes such requirements. States and affected EGUs should plan accordingly to avoid noncompliance.

The EPA is finalizing a state plan submission date that is 24 months after the publication of the final emission guidelines and is finalizing the first compliance date for affected coal-fired EGUs in the medium-term subcategory and affected natural gas- and oil-fired EGUs of January 1, 2030. A state may choose to submit a plan revision prior to the compliance dates in its existing state plan; however, the EPA reiterates that any already approved federally enforceable requirements, including milestones, increments of progress, and standards of performance, will remain in place unless and until the EPA approves the plan revision.

The EPA requested comment on whether it would be helpful to states to impose a cutoff date for the submission of plan revisions before the first compliance date. This would, in effect, establish a temporary moratorium on plan submissions in order to allow the EPA to act on the plans. State plan revisions would again be permitted after the final compliance date. The EPA is not finalizing such cutoff date to provide more flexibility to states in submitting revisions closer to the first compliance date, in the case that EPA may be able to review those revisions before the first compliance date.

Comment: Several commenters generally disagreed with establishing a cutoff date for state plan revisions before the first compliance date, arguing these timelines would be unworkable because state plan revisions may require public notice and stakeholder engagement.

Response: The EPA is not finalizing an explicit cutoff date that would in effect establish a temporary moratorium on plan submissions; however, the EPA notes that, because the first compliance date under the final emission guidelines is January 1, 2030, a plan revision submitted after November 1, 2028 (taking into consideration 1 year for EPA action on a state plan revision plus up to 60 days, approximately, for a completeness determination) may not provide sufficient time for the EPA to review and approve the plan sufficiently in advance of that compliance date to allow sources to appropriately plan for compliance. The EPA reiterates that EGUs will be expected to comply with any requirements already approved in the state plan until such time as the plan revision is approved.

4. Dual-Path Standards of Performance for Affected EGUs

As discussed in the proposed action, under the structure of these emission guidelines, states would assign affected coal-fired EGUs to subcategories in their state plans, and an affected EGU would not be able to change its applicable subcategory without a state plan revision. This is because, due to the nature of the BSERs for coal-fired steam generating units, an affected EGU that switches into either the medium-term or long-term subcategory may not be able to meet the compliance obligations for a new and different subcategory without considerable lead time; in order to ensure timely emission reductions, it is important that states identify which subcategories affected EGUs fall into in their state plan submissions so that affected EGUs have certainty about their expected regulatory obligations. Therefore, as a general matter, states must assign each affected EGU to a subcategory and have in place all the legal instruments necessary to implement the requirements for that subcategory by the time of state plan submission.

However, the EPA also solicited comment on a dual-path approach that would allow coal-fired steam generating units to have two different standards of performance submitted to the EPA in a state plan based on potential inclusion in two different subcategories. This proposal was based in large part on the proposed structure of the subcategories for coal-fired affected EGUs, under which it would have been realistic to expect that sources could prepare to comply with either the presumptive standard of performance for, *e.g.*, the imminent-term subcategory and the near-term subcategory or the imminent-term subcategory and the medium-term subcategory.

Because the final emission guidelines include only two subcategories for coal-

[977] 40 CFR 60.23a(a)(2), 60.28a.

fired affected EGUs and do not include the two subcategories for which the dual-path approach would have been appropriate, the EPA is not finalizing an approach that allows coal-fired steam generating units to have two different standards of performance submitted to the EPA in a state plan based on potential inclusion in two different subcategories.

Comment: In general, commenters supported a dual-path approach; however, several commenters requested that the EPA accommodate a multi-pathway approach (three or more pathways) due to the complexity of state plans and potential for numerous compliance pathways because of factors beyond the EGU owner or operator's control, such as infrastructure for CCS projects and increase in electric power demand due to electrification of the transportation sector.

Response: As stated above, the EPA is not finalizing the dual-path approach, nor a multi-pathway approach. If an affected EGU wishes to switch subcategories after the initial state plan approval, the state should submit a state plan revision sufficiently in advance of the compliance date for the subcategory into which it was assigned to permit the EPA's review and action on that plan revision.

5. EPA Action on State Plans

Pursuant to the final revisions to 40 CFR part 60, subpart Ba, in this action, the EPA is subject to a 60-day timeline for the Administrator's determination of completeness of a state plan submission and a 12-month timeline for action on state plans.[978] The timeframes and requirements for state plan submissions described in this section also apply to state plan revisions.[979]

As discussed in the proposed action, the EPA would first review the components of the state plan to determine whether the plan meets the completeness criteria of 40 CFR 60.27a(g). The EPA must determine whether a state plan submission has met the completeness criteria within 60 days of its receipt of that submission. If the EPA has failed to make a completeness determination for a state plan submission within 60 days of receipt, the submission shall be deemed, by operation of law, complete as of that date. Subpart Ba requires the EPA to take final action on a state plan submission within 12 months of that submission's being deemed complete. The EPA will review the components of state plan submissions against the applicable requirements of subpart Ba and these emission guidelines, consistent with the underlying requirement that state plans must be "satisfactory" per CAA section 111(d). The Administrator would have the option to fully approve; fully disapprove; partially approve and partially disapprove; or conditionally approve a state plan submission.[980] Any components of a state plan submission that the EPA approves become federally enforceable.

The EPA solicited comment on the use of the timeframes regarding EPA action on state plans in subpart Ba and commenters encouraged reconsidering the schedule, suggesting either increasing or decreasing the amount of time for action on state plans. In the final emission guidelines, the EPA is not superseding the timeframes in subpart Ba regarding EPA action on state plans and plan revisions.

Comment: One commenter suggested that the EPA should provide for automatic extension of compliance dates for affected EGUs if the Agency does not meet its 12-month deadline for plan approval.[981] Other commenters expressed concerns that the EPA will be unable to review all plans in the 12-month timeframe. One commenter suggested that the EPA should strive to review plans in less than the proposed 12-month timeframe.[982]

Response: The EPA does not believe it is appropriate to provide automatic extensions of compliance dates based on the timeframe for EPA action on state plan submissions. While there may be some degree of regulatory uncertainty that stems from waiting for the Agency to act on a state plan submission, it would not be a reasonable solution to add to that uncertainty by also making compliance dates contingent on the date of EPA's action. This additional uncertainty could have the effect of unnecessarily extending the compliance schedule and delaying emission reductions. Given that the dates on which the EPA takes final action on individual state plans are likely to be many and varied (based on, *inter alia,* when each state plan was submitted to the Agency), such extensions would create unnecessary confusion and potentially uneven application of the requirements for state plans. In this action, the EPA does not find a reason to supersede the timelines finalized in subpart Ba; therefore, review of and action on state plan submissions will be governed by the requirements of revised subpart Ba.

6. Federal Plan Applicability and Promulgation Timing

The provisions of 40 CFR part 60, subpart Ba, apply to the EPA's promulgation of any Federal plans under these emission guidelines. The EPA's obligation to promulgate a Federal plan is triggered in three situations: where a state does not submit a plan by the plan submission deadline; where the EPA determines that a state plan submission does not meet the completeness criteria and the time period for state plan submission has elapsed; and where the EPA fully or partially disapproves a state's plan.[983] Where a state has failed to submit a plan by the submission deadline, subpart Ba gives the EPA 12 months from the state plan submission due date to promulgate a Federal plan; otherwise, the 12-month period starts, as applicable, from the date the state plan submission is deemed incomplete or from the date of the EPA's disapproval. If the state submits and the EPA approves a state plan submission that corrects the relevant deficiency within the 12-month period, before the EPA promulgates a Federal plan, the EPA's obligation to promulgate a Federal plan is relieved.[984]

As provided by 40 CFR 60.27a(e), a Federal plan will prescribe standards of performance for affected EGUs of the same stringency as required by these emission guidelines and will require compliance with such standards as expeditiously as practicable but no later than the final compliance date under these guidelines. However, 40 CFR 60.27a(e)(2) provides that, upon application by the owner or operator of an affected EGU, the EPA may provide for the application of a less stringent standard of performance or longer compliance schedule than provided by these emission guidelines, in which case the EPA would follow the same process and criteria in the regulations that apply to states' provision of RULOF standards. Under subpart Ba, the EPA is also required to conduct meaningful engagement with pertinent stakeholders prior to promulgating a Federal plan.[985]

As discussed in section X.E.2 of this preamble, the EPA is finalizing a deadline for state plan submissions of 24 months after publication of these final emission guidelines in the **Federal Register**. Therefore, if a state fails to timely submit a state plan, the EPA

[978] 40 CFR 60.27a(b), (g)(1).

[979] See generally 40 CFR 60.27a.

[980] 40 CFR 60.27a(b).

[981] See Document ID No. EPA–HQ–OAR–2023–0072–0660.

[982] See Document ID No. EPA–HQ–OAR–2023–0072–0764.

[983] 40 CFR 60.27a(c).

[984] 40 CFR 60.27a(d).

[985] 40 CFR 60.27a(f).

would be obligated to promulgate a Federal plan within 36 months of publication of these final emission guidelines. Note that this will be the earliest possible obligation for the EPA to promulgate a Federal plan and that different triggers (*e.g.*, a disapproved state plan) will result in later obligations to promulgate Federal plans for other states, contingent on when the obligation is triggered.

Finally, the EPA acknowledges that, if a Tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for areas of Indian country where designated facilities are located. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves an applicable TIP applicable to those facilities.

XI. Implications for Other CAA Programs

A. New Source Review Program

The CAA's New Source Review (NSR) preconstruction permitting program applies to stationary sources that emit pollutants resulting from new construction and modifications of existing sources. The NSR program is authorized by CAA section 110(a)(2)(C), which requires that each state implementation plan (SIP) ''include a program to provide for the . . . regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that [NAAQS] are achieved, including a permit program as required in parts C and D [of title I of the CAA].'' The ''permit program as required in parts C and D'' refers to the ''major NSR'' program, which applies to new ''major stationary sources''[986] and ''major modifications''[987] of existing stationary sources. The ''minor NSR'' program applies to new construction and modifications of stationary sources that do not meet the emission thresholds for major NSR. NSR applicability is pollutant-specific, so a source seeking to newly construct or modify may need to obtain both major NSR and minor NSR permits before it can begin construction.

Under the CAA, states have primary responsibility for issuing NSR permits, and they can customize their programs within the limits of EPA regulations. The Federal NSR rules applying to state permitting authorities are found at 40 CFR 51.160 to 51.166. The EPA's primary role is to approve state program regulations and to review, comment on, and take any other necessary actions on draft and final permits to assure consistency with the EPA's rules, the SIP, and the CAA. When a state does not have EPA-approved authority to issue NSR permits, the EPA issues the NSR permits within the state, or delegates authority to the state to issue the NSR permits on behalf of the EPA, pursuant to rules at 40 CFR 49.151–173, 40 CFR 52.21, and 40 CFR 124.

For the major NSR program, the requirements that apply to a source depend on the air quality designation at the location of the source for each of its emitted pollutants at the time the permit is issued. Major NSR permits for sources located in an area that is designated as attainment or unclassifiable for the NAAQS for its pollutants are referred to as Prevention of Significant Deterioration (PSD) permits. PSD permits can include requirements for specific pollutants for which there are no NAAQS.[988] Sources subject to PSD must, among other requirements, comply with emission limitations that reflect the Best Available Control Technology (BACT) for ''each pollutant subject to regulation'' as specified by CAA sections 165(a)(4) and 169(3). Major NSR permits for sources located in nonattainment areas and that emit at or above the specified major NSR threshold for the pollutant for which the area is designated as nonattainment are referred to as Nonattainment NSR (NNSR) permits. Sources subject to NNSR must, among other requirements, meet the Lowest Achievable Emission Rate (LAER) pursuant to CAA sections 171(3) and 173(a)(2) for any pollutant subject to NNSR. For the minor NSR program, neither the CAA nor the EPA's rules set forth a minimum control technology requirement.

In keeping with the goal of progress toward attaining the NAAQS, sources seeking NNSR permits must provide or purchase ''offsets''—*i.e.*, decreases in emissions that compensate for the increases from the new source or modification. For sources seeking PSD permits, offsets are not required, but they must demonstrate that the emissions from the project will not cause or contribute to a violation of the NAAQS or the ''PSD increments'' (*i.e.*, margins of ''significant'' air quality deterioration above a baseline concentration that establish an air quality ceiling, typically below the NAAQS, for each PSD area). Sources can often make this air quality demonstration based on the BACT level of control or by accepting more stringent air quality-based limitations. However, if these methods are insufficient to show that increased emissions from the source will not cause or contribute to a violation of air quality standards, applicants may undertake mitigation measures that are analogous to offsets in order to satisfy this PSD permitting criterion.

When the EPA is making NSR permitting decisions, it has legal authority to consider potential disproportionate environmental burdens on a case-by-case basis. Based on Executive Order (E.O.) 12898, the EPA's Environmental Appeals Board (EAB) has held that environmental justice considerations must be considered in connection with the issuance of Federal PSD permits issued by EPA Regional Offices or states acting under delegations of Federal authority. The EAB ''has . . . encouraged permit issuers to examine any 'superficially plausible' claim that a minority or low-income population may be disproportionately affected by a particular facility.''[989] EPA guidance and EAB decisions do not advise EPA Regional Offices or delegated NSR permitting authorities to integrate environmental justice considerations into any particular component of the PSD permitting review, such as the determination of BACT. The practice of EPA Regional Offices and delegated states has been to conduct a largely freestanding environmental justice analysis for PSD permits that can take into account case-specific factors germane to any individual permit decision.

The minimum requirements for an approvable state NSR permitting program do not require state permitting authorities to reflect environmental justice considerations in their permitting decisions. However, states that implement NSR programs under an EPA-approved SIP have discretion to consider environmental justice in their NSR permitting actions and adopt additional requirements in the permitting decision to address potential disproportionate environmental burdens. Additionally, in some cases, a

[986] 40 CFR 52.21(b)(1)(i).

[987] 40 CFR 52.21(b)(2)(i) and the term ''net emissions increase'' as defined at 40 CFR 52.21(b)(3).

[988] For the PSD program, ''regulated NSR pollutant'' includes any pollutant for which a NAAQS has been promulgated (''criteria pollutants'') and any other air pollutant that meets the requirements of 40 CFR 52.21(b)(50). Some of these non-criteria pollutants include greenhouse gases, fluorides, sulfuric acid mist, hydrogen sulfide, and total reduced sulfur.

[989] *In re Shell Gulf of Mexico, Inc.*, 15 E.A.D. 103, 149 and n.71 (EAB 2010) (internal citations omitted).

state law requires consideration of environmental justice in the state's permitting decisions.

Through the NSR permit review process, permitting authorities have requirements for public participation in decision-making, which provide discretion for permitting authorities to provide enhanced engagement for communities with environmental justice concerns. This includes opportunities to enhance environmental justice by facilitating increased public participation in the formal permit consideration process (*e.g.*, by granting requests to extend public comment periods, holding multiple public meetings, or providing translation services at hearings in areas with limited English proficiency). The permitting authority can also take informal steps to enhance participation earlier in the process, such as inviting community groups to meet with the permitting authority and express their concerns before a draft permit is issued.

Additionally, in accordance with CAA 165(a)(2), the PSD regulations require the permitting authority to ''[p]rovide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations.'' 40 CFR 51.166(q)(2)(v). The ''alternatives'' and ''other appropriate considerations'' language in CAA 165(a)(2) can be interpreted to provide the permitting authority with discretion to incorporate siting and environmental justice considerations when issuing PSD permits—specifically, to impose permit conditions on the basis of environmental justice considerations raised in public comments regarding the air quality impacts of a proposed source. The EAB has recognized that consideration of the need for a facility is within the scope of CAA 165(a)(2) when a commenter raises the issue. The EPA has recognized that this language provides a potential statutory foundation in the CAA for this discretion.[990] The Federal regulations for NNSR permits also have an analysis of alternatives required by CAA 173(a)(5). 40 CFR 51.165(i).

1. Control Technology Reviews for Major NSR Permits

The statutory and regulatory basis for a control technology review for a source undergoing major NSR permitting differs from the criteria required in establishing an NSPS or emission guidelines. As such, sources that are permitted under major NSR may have differing control requirements for a pollutant than what is required by an applicable standard under CAA section 111. As noted above, sources permitted under the minor NSR program do not have a minimum control technology standard specified by statute or EPA rule, so a permitting authority has more flexibility in its determination of control technology for aminor NSR permit.

For PSD permits, the permitting authority must establish emission limitations based on BACT for each pollutant that is subject to PSD at the new major stationary source or at each emissions unit involved in the major modification. BACT is assessed on a case-by-case basis, and the permitting authority, in its analysis of BACT for each pollutant, evaluates the emission reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic, and other costs associated with each technology or technique. The CAA also specifies that BACT cannot be less stringent than any applicable standard of performance under the NSPS.[991]

In conducting a BACT analysis, many permitting authorities apply the EPA's five-step ''top-down'' approach, which the EPA recommends to ensure that all the criteria in the CAA's definition of BACT are considered. This approach begins with the permitting authority identifying all available control options that have the potential for practical application for the regulated NSR pollutant and emissions unit under evaluation. The analysis then evaluates each option and eliminates options that are technically infeasible, ranks the remaining options from most to least effective, evaluates the energy, environmental, economic impacts, and other costs of the options, eliminates options that are not achievable based on these considerations from the top of the list down, and ultimately selects the most effective remaining option as BACT.[992]

While the BACT review process is intended to capture a broad array of potential options for pollution control, the EPA has recognized that the list of available control options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. Thus, BACT should generally not be applied to regulate the permit applicant's purpose or objective for the proposed facility. However, this approach does not preclude a permitting authority from considering options that would change aspects (either minor or significant) of an applicants' proposed facility design in order to achieve pollutant reductions that may or may not be deemed achievable after further evaluation at later steps of the process. The EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire. The ''redefining the source'' issue is ultimately a question of degree that is within the discretion of the permitting authority, and any decision to exclude an option on ''redefining the source'' grounds should be explained and documented in the permit record.

In conducting the analysis of energy, environmental and economic impacts arising from each control option remaining under consideration, permitting authorities have considerable discretion in deciding the specific form of the BACT analysis and the weight to be given to the particular impacts under consideration. The EPA and other permitting authorities have most often used this analysis to eliminate more stringent control technologies with significant or unusual effects that are unacceptable in favor of the less stringent technologies with more acceptable collateral environmental effects. Permitting authorities may consider a wide variety of environmental impacts in this analysis, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, demand on local water resources, and emissions of other pollutants subject to NSR or pollutants not regulated under NSR such as air toxics. A permitting authority could place more weight on the collateral environmental effect of a control alternative on local communities—*e.g.*, if emission increases of co-pollutants from operating the control device may disproportionately

[990] See Memorandum from Gary S. Guzy, EPA General Counsel, titled *EPA Statutory and Regulatory Authorities Under Which Environmental Justice Issues May Be Addressed in Permitting* (December 1, 2000).

[991] 42 U.S.C. 7479(3) (''In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to [CAA Section 111 or 112].'').

[992] For more information on EPA's recommended BACT approach, see U.S. Environmental Protection Agency, New Source Review Workshop Manual (October 1990; Draft) at *https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf* and U.S. Environmental Protection Agency, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011; EPA–457/B–11–001) at *https://www.epa.gov/sites/default/files/2015-07/documents/ghgguid.pdf.*

affect a minority or low-income population—which may result in the permitting authority eliminating that control option and ultimately selecting a less stringent control technology for the target pollutant as BACT because it has more acceptable collateral impacts.

In addition, this analysis may extend to considering reduced, or excessive, energy or environmental impacts of the control alternative at an offsite location that is in support the operation of the facility obtaining the permit. For example, in the case of a facility that proposes to co-fire its new stationary combustion turbines with hydrogen procured from an offsite production facility, a permitting authority may determine it is appropriate to weigh favorably a control option that involves co-firing with hydrogen produced from low-GHG emitting processes, such as electrolysis powered by renewable energy, to recognize the reduced environmental impact of producing the fuel for the control option.

For NNSR permits, the statutory requirement for establishing LAER is more prescriptive and, consequently, tends to provide less discretion to permitting authorities than the discretion allowed under BACT. For new major stationary sources and major modifications in nonattainment areas, LAER is defined as the most stringent emission limitation required under a SIP or achieved in practice for a class or category of sources. Thus, unlike BACT, the LAER requirement does not consider economic, energy, or other environmental factors, except that LAER is not considered achievable if the cost of control is so great that a major new stationary source could not be built or operated.[993] As with BACT determinations, a determination of LAER cannot be less stringent than any applicable NSPS.[994]

2. NSR Implications of the NSPS

Any source that is planning to install a new or reconstructed EGU that meets the applicability of this final NSPS will likely require an NSR permit prior to its construction. In addition to including conditions for GHG emissions, the NSR permit would contain emission limitations for the non-GHG pollutants emitted by the new or reconstructed EGU. Depending on the level of emissions for each pollutant, the source may require a major NSR permit, minor NSR permit, or a combination of both types of permits.

As GHGs are regulated pollutants under the PSD program, this NSPS serves as the minimum level of control in determining BACT for any new major stationary source or major modification that meets the applicability of this NSPS and commences construction on its affected EGU(s) after the date of publication of the proposed NSPS in the **Federal Register**. However, as explained above, the fact that a minimum control requirement for BACT is established by an applicable NSPS does not mean that a permitting authority cannot select a more stringent control level for the PSD permit or consider control technologies for BACT beyond those that were considered in developing the NSPS. The authority for BACT is separate from that of BSER, and it requires a case-by-case review of a specific stationary source at the time its owner or operator applies for a PSD permit. Accordingly, the BACT analysis for a source with an applicable NSPS should reflect source-specific factors and any advances in control technology, reductions in the costs or other impacts of using particular control strategies, or other relevant information that may have become available after the EPA issued the NSPS.

3. NSR Implications of the Emission Guidelines

With respect to the final emission guidelines, each state will develop a plan that establishes standards of performance for each affected EGU in the state that meets the applicability criteria of this emission guidelines. In doing so, a state agency may develop a plan that requires an existing stationary source to undertake a physical or operational change. Under the NSR program, when a stationary source undertakes a physical or operational change, even if it is doing so to comply with a national or state level requirement, the source may need to obtain a preconstruction NSR permit, with the type of permit (*i.e.,* NNSR, PSD, or minor NSR) depending on the amount of the emissions increase resulting from the change and the air quality designation at the location of the source for its emitted pollutants. However, since emission guidelines are intended to reduce emissions at an existing stationary source, a NSR permit may not be needed to perform the physical or operational change required by the state plan if the change will not increase emissions at the source.

As noted elsewhere in this preamble, sources that will be complying with their state plan's standards of performance by installing and operating CCS could experience criteria pollutant emission increases that may result in the source triggering major NSR requirements. If a source with an affected EGU does trigger major NSR requirements for one or more pollutants as a result of complying with its standards of performance, the permitting authority would conduct a control technology review (*i.e.,* BACT or LAER, as appropriate) for each of the pollutants and require that the source comply with the other applicable major NSR requirements. As noted in section VII of this preamble, in light of concerns expressed by stakeholders over possible co-pollutant increases from CCS retrofit projects, the EPA plans to review its NSR guidance and determine how it can be updated to better assist permit applicants and permitting authorities in conducting BACT reviews for sources that intend to install CCS.

States may also establish the standards of performance in their plans in such a way so that their affected sources, in complying with those standards, in fact would not have emission increases that trigger major NSR requirements. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the standards of performance, their emissions would not increase in a way that trigger major NSR requirements. For example, a state could, as part of its state plan, develop enforceable conditions for a source expected to trigger major NSR that would effectively limit the unit's ability to increase its emissions in amounts that would trigger major NSR (effectively establishing a synthetic minor limitation).[995] Some commenters asserted that base load units may not be able to readily rely on this option to limit their emission increases given the need for those units to respond to demand and maintain grid reliability. In these cases, states may adopt other strategies in their state plans to ensure that base load units have the needed flexibility to operate and do so without triggering major NSR requirements.

[993] New Source Review Workshop Manual (October 1990; Draft), page G.4.

[994] 42 U.S.C. 7501(3); 40 CFR 51.165(a)(1)(xiii); 40 CFR part 51, appendix S, section II.A.18.

[995] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. See, *e.g.,* CAA sections 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or title V permitting programs. See, *e.g.,* 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of "potential to emit").

B. Title V Program

Title V regulations require each permit to include emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements. Requirements resulting from these rules that are imposed on EGUs or other potentially affected entities that have title V operating permits are applicable requirements under the title V regulations and would need to be incorporated into the source's title V permit in accordance with the schedule established in the title V regulations. For example, if the permit has a remaining life of 3 years or more, a permit reopening to incorporate the newly applicable requirement shall be completed no later than 18 months after promulgation of the applicable requirement. If the permit has a remaining life of less than 3 years, the newly applicable requirement must be incorporated at permit renewal.[996] Additionally, proceedings to reopen and issue a permit shall follow the same procedures that apply to initial permit issuance and only affect the parts of the permit for which cause to reopen exists. The reopening of permits is expected to be made as expeditiously as possible.[997]

In the proposal, the EPA also indicated that if a state needs to include provisions related to the state plan in a source's title V permit before submitting the plan to the EPA, these limits should be labeled as ''state-only'' or ''not federally enforceable'' until the EPA has approved the state plan. The EPA solicited comments on whether, and under what circumstances, states might use this mechanism. While no specific comments were received on this point, the EPA would like to further clarify that in finalizing this direction, the intention is to ensure that meaningful public participation is available during the development of a state plan, rather than limiting engagement to the permitting process. While the public would have the opportunity to comment on the individual permit provisions, this would not allow for the opportunity to comment on the plan as a whole before it is finalized.

XII. Summary of Cost, Environmental, and Economic Impacts

In accordance with E.O. 12866 and 13563, the guidelines of the Office of Management and Budget (OMB) Circular A–4 and the EPA's Guidelines for Preparing Economic Analyses, the EPA prepared an RIA for these final actions. The RIA is separate from the EPA's statutory BSER determinations and did not influence the EPA's choice of BSER for any of the regulated source categories or subcategories. This RIA presents the expected economic consequences of the EPA's final rules, including analysis of the benefits and costs associated with the projected emission reductions for three illustrative scenarios. The first scenario represents the final NSPS and emission guidelines in combination. The second and third scenarios represent different stringencies of the combined policies. All three illustrative scenarios are compared against a single baseline. For detailed descriptions of the three illustrative scenarios and the baseline, see section 1 of the RIA, which is titled ''Regulatory Impact Analysis for the 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'' and is available in the rulemaking docket.[998]

The three scenarios detailed in the RIA, including the final rules scenario, are illustrative in nature and do not represent the plans that states may ultimately pursue. As there are considerable flexibilities afforded to states in developing their state plans, the EPA does not have sufficient information to assess specific compliance measures on a unit-by-unit basis. Nonetheless, the EPA believes that such illustrative analysis can provide important insights.

In the RIA, the EPA evaluates the potential impacts of the three illustrative scenarios using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2024 to 2047 from the perspective of 2019. In addition, the EPA presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with the Agency's historic practice. These specific snapshot years are 2028, 2030, 2035, 2040, and 2045. In addition to the core benefit-cost analysis, the RIA also includes analyses of anticipated economic and energy impacts, environmental justice impacts, and employment impacts.

The analysis presented in this preamble section summarizes key results of the illustrative final rules scenario. For detailed benefit-cost results for the three illustrative scenarios and results of the variety of impact analysis just mentioned, please see the RIA, which is available in the docket for this action.

It should be noted that for the RIA for this rulemaking, the EPA undertook the same approach to determine benefits and costs as it has generally taken in prior rulemakings concerning the electric power sector. It does not rely on the benefit-cost results included in the RIA as part of its BSER analysis. Rather, the BSER analysis considers the BSER criteria as set out in CAA section 111(a)(1) and the caselaw—including the costs of the controls to the source, the amount of emission reductions, and other criteria—as described in section V.C.2.

A. Air Quality Impacts

For the analysis of the final rules, total cumulative power sector CO_2 emissions between 2028 and 2047 are projected to be 1,382 million metric tons lower under the illustrative final rules scenario than under the baseline. Table 4 shows projected aggregate annual electricity sector emission changes for the illustrative final rules scenario, relative to the baseline.

TABLE 4—PROJECTED ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE

	CO_2 (million metric tons)	Annual NO_X (thousand short tons)	Ozone season NO_X (thousand short tons)	Annual SO_2 (thousand short tons)	Direct $PM_{2.5}$ (thousand short tons)	Mercury (tons)
2028	−38	−20	−6	−34	−2	−0.1

[996] *See* 40 CFR 70.7(f)(1)(i).

[997] *See* 40 CFR 70.7(f)(2).

[998] The EPA also examined the final rules under a variety of different assumptions regarding demand, gas price, and contemporaneous rulemakings and determined that those alternative projections, inclusive of CCS buildout and cost profiles, would not alter any BSER design parameters selected in this action. For further discussion, see the technical memorandum, *IPM Sensitivity Runs,* available in the rulemaking docket.

TABLE 4—PROJECTED ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE—Continued

	CO_2 (million metric tons)	Annual NO_X (thousand short tons)	Ozone season NO_X (thousand short tons)	Annual SO_2 (thousand short tons)	Direct $PM_{2.5}$ (thousand short tons)	Mercury (tons)
2030	−50	−20	−7	−20	−2	−0.1
2035	−123	−49	−19	−90	−1	−0.1
2040	−54	−6	−6	−4	2	0.2
2045	−42	−24	−14	−41	−2	−0.2

Note: Ozone season is the May through September period in this analysis.

B. Compliance Cost Impacts

The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and illustrative scenarios, including the cost of monitoring, reporting, and recordkeeping. In simple terms, these costs are an estimate of the increased power industry expenditures required to comply with the final actions.

The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the plans that states may ultimately pursue. The illustrative final rules scenario is designed to reflect, to the extent possible, the scope and nature of the final rules. However, there is uncertainty with regards to the precise measures that states will adopt to meet the requirements because there are flexibilities afforded to the states in developing their state plans.

The IRA is projected to accelerate the ongoing shift towards lower-emitting technology. In particular, under the baseline tax credits for low-emitting technology results in growing generation share for renewable resources and the deployment of 11 GW of CCS retrofits on existing coal-fired steam generating units by 2035. New combined cycle builds are 20 GW by 2030, and existing coal capacity continues to decline, falling to 84 GW by 2030 and 31 GW by 2040. Under the illustrative final rules scenario, the EPA projects an incremental 8 GW of CCS retrofits on existing coal-fired steam generating units by 2035 relative to the baseline. By 2035, relative to the baseline, new combined cycle builds are 2 GW lower, new combustion turbine builds are 10 GW higher, and wind and solar additions are 15 GW higher. Total coal capacity is projected to be 73 GW in 2030 and 19 GW by 2040. As a result, the compliance cost of the final rules is lower than it would be absent the IRA.

We estimate the PV of the projected compliance costs for the analysis of the final standards for new combustion turbines and for existing steam generating EGUs over the 2024 to 2047 period, as well as estimate the equivalent annual value (EAV) of the flow of the compliance costs over this period. The EAV represents a flow of constant annual values that, had they occurred annually, would yield a sum equivalent to the PV. All dollars are in 2019 dollars. We estimate the PV and EAV using discount rates of 2 percent, 3 percent, and 7 percent.[999] The PV of compliance costs discounted at the 2 percent rate is estimated to be about 19 billion, with an EAV of about 0.98 billion. At the 3 percent rate, the PV of compliance costs is estimated to be about 15 billion, with an EAV of about 0.91 billion. At the 7 percent discount rate, the PV of compliance costs is estimated to be about 7.5 billion, with an EAV of about 0.65 billion. To put this in perspective, this levelized compliance cost is roughly one percent of the total projected levelized cost to produce electricity over the same timeframe under the baseline.

Section 3 of the RIA presents detailed discussions of the compliance cost projections for the final rule requirements, as well as projections of compliance costs for less and more stringent regulatory options.

C. Economic and Energy Impacts

These final actions have economic and energy market implications. The energy impact estimates presented here reflect the EPA's illustrative analysis of the final rules. States are afforded flexibility to implement the final rules, and thus the estimated impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. In addition, as discussed in section VII.E.1 of this preamble, the factors driving these impacts, including potential revenue streams for captured carbon, may change over the next 25 years, leading the estimated impacts to be different than reality. Table 5 presents a variety of energy market impact estimates for 2028, 2030, 2035, 2040, and 2045 for the illustrative final rules scenario, relative to the baseline.

TABLE 5—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE

[Percent change]

	2028 (%)	2030 (%)	2035 (%)	2040 (%)	2045 (%)
Retail electricity prices	−1	0	1	0	1
Average price of coal delivered to power sector	−1	−1	0	0	−32
Coal production for power sector use	−6	−4	−21	15	−84
Price of natural gas delivered to power sector	−2	0	3	0	0
Price of average Henry Hub (spot)	−2	−1	3	0	0

[999] Results using the 2 percent discount rate were not included in the proposals for these actions. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rules used these two recommended rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates). The Circular A–4 update also recommended consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. As a result of the update to Circular A–4, we include cost and benefits results calculated using a 2 percent discount rate.

TABLE 5—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE—Continued

[Percent change]

	2028 (%)	2030 (%)	2035 (%)	2040 (%)	2045 (%)
Natural gas use for electricity generation	−1	−2	4	0	2

These and other energy market impacts are discussed more extensively in section 3 of the RIA.

More broadly, changes in production in a directly regulated sector may have effects on other markets when output from that sector—for these rules, electricity—is used as an input in the production of other goods. It may also affect upstream industries that supply goods and services to the sector, along with labor and capital markets, as these suppliers alter production processes in response to changes in factor prices. In addition, households may change their demand for particular goods and services due to changes in the price of electricity and other final goods prices. Economy-wide models—and, more specifically, computable general equilibrium (CGE) models—are analytical tools that can be used to evaluate the broad impacts of a regulatory action. A CGE-based approach to cost estimation concurrently considers the effect of a regulation across all sectors in the economy.

In 2015, the EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory analysis. In its final report, the SAB recommended that the EPA begin to integrate CGE modeling into applicable regulatory analysis to offer a more comprehensive assessment of the effects of air regulations.[1000] In response to the SAB's recommendations, the EPA developed a new CGE model called SAGE designed for use in regulatory analysis. A second SAB panel performed a peer review of SAGE, and the review concluded in 2020.[1001]

The EPA used SAGE to evaluate potential economy-wide impacts of these final rules, and the results are contained in section 5.2 of the RIA. Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits. The annualized social cost estimated in SAGE for the finalized rules is approximately $1.32 billion (2019 dollars) between 2024 and 2047 using a 4.5 percent discount rate that is consistent with the internal discount rate in the model. Under the assumption that compliance costs from IPM in 2056 continue until 2081, the equivalent annualized value for social costs in the SAGE model is $1.51 billion (2019 dollars) over the period from 2024 to 2081, again using a 4.5 percent discount rate that is consistent with the internal discount rate of the model. The social cost estimate reflects the combined effect of the final rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the final rules. We are not able to identify their relative roles currently.

At proposal, the EPA solicited comment on the SAGE analysis presented in the RIA appendix. The SAGE analysis of the final rules is responsive to those comments. The comments received were supportive of the use of SAGE for estimating economy-wide social costs and other economy-wide impacts alongside the IPM-based cost and benefit estimates. The comments also suggested a variety of sensitivity analyses and several longer-term research goals for improving the capabilities of SAGE, such as adding a representation of emissions changes. For more detailed comment summaries and responses, see the response to comments in the docket for these actions.

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Employment impacts of these final actions are discussed more extensively in section 5 of the RIA.

D. Benefits

This section includes the estimated total benefits and the estimated net benefits of the final rules.

1. Total Benefits

Pursuant to E.O. 12866, the RIA for these actions analyzes the benefits associated with the projected emission changes under the final rules to inform the EPA and the public about these projected impacts. These final rules are projected to reduce national emissions of CO_2, SO_2, NO_X, and $PM_{2.5}$, which we estimate will provide climate benefits and public health benefits. The potential climate, health, welfare, and water quality impacts of these emission changes are discussed in detail in the RIA. In the RIA, the EPA presents the projected monetized climate benefits due to reductions in CO_2 emissions and the monetized health benefits attributable to changes in SO_2, NO_X, and $PM_{2.5}$ emissions, based on the emissions estimates in illustrative scenarios described previously. We monetize benefits of the final rules and evaluate other costs in part to enable a comparison of costs and benefits pursuant to E.O. 12866, but we recognize that there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified or monetized.

We emphasize that the monetized benefits analysis is entirely distinct from the statutory BSER determinations finalized herein and is presented solely for the purposes of complying with E.O. 12866. As discussed in more detail in the proposal and earlier in this action, the EPA weighed the relevant statutory factors to determine the appropriate standards and did not rely on the monetized benefits analysis for purposes of determining the standards. E.O. 12866 separately requires the EPA to perform a benefit-cost analysis, including monetizing costs and benefits where practicable, and the EPA has conducted such an analysis.

The EPA estimates the climate benefits of GHG emissions reductions expected from the final rules using estimates of the social cost of greenhouse gases (SC–GHG) that reflect recent advances in the scientific

[1000] U.S. EPA. 2017. SAB Advice on the Use of Economy-Wide Models in Evaluating the Social Costs, Benefits, and Economic Impacts of Air Regulations. EPA–SAB–17–012.

[1001] U.S. EPA. 2020. Technical Review of EPA's Computable General Equilibrium Model, SAGE. EPA–SAB–20–010.

literature on climate change and its economic impacts and that incorporate recommendations made by the National Academies of Science, Engineering, and Medicine.[1002] The EPA published and used these estimates in the RIA for the Final Oil and Gas Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, which was signed by the EPA Administrator on December 2, 2023.[1003] The EPA solicited public comment on the methodology and use of these estimates in the RIA for the Agency's December 2022 Oil and Gas Supplemental Proposal and has conducted an external peer review of these estimates, as described further below. Section 4 of the RIA lays out the details of the updated SC–GHG used within this final rule.

The SC–GHG is the monetary value of the net harm to society associated with a marginal increase in GHG emissions in a given year, or the benefit of avoiding that increase. In principle, SC–GHG 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 and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–GHG, therefore, reflects the societal value of reducing emissions of the gas in question by 1 metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect GHG emissions. In practice, data and modeling limitations restrain the ability of SC–GHG estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Since 2008, the EPA has used estimates of the social cost of various greenhouse gases (*i.e.*, SC–CO_2, SC–CH_4, and SC–N_2O), collectively referred to as the "social cost of greenhouse gases" (SC–GHG), in analyses of actions that affect GHG emissions. The values used by the EPA from 2009 to 2016, and since 2021—including in the proposal—have been consistent with those developed and recommended by the IWG on the SC–GHG; and the values used from 2017 to 2020 were consistent with those required by E.O. 13783, which disbanded the IWG. During 2015–2017, the National Academies conducted a comprehensive review of the SC–CO_2 and issued a final report in 2017 recommending specific criteria for future updates to the SC–CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process.[1004] The IWG was reconstituted in 2021 and E.O. 13990 directed it to develop a comprehensive update of its SC–GHG estimates, recommendations regarding areas of decision-making to which SC–GHG should be applied, and a standardized review and updating process to ensure that the recommended estimates continue to be based on the best available economics and science going forward.

The EPA is a member of the IWG and is participating in the IWG's work under E.O. 13990. As noted in previous EPA RIAs (including in the proposal RIA for this rulemaking), while that process continues, the EPA is continuously reviewing developments in the scientific literature on the SC–GHG, including more robust methodologies for estimating damages from emissions, and is looking for opportunities to further improve SC–GHG estimation.[1005] In the December 2022 Oil and Gas Supplemental Proposal RIA,[1006] the Agency included a sensitivity analysis of the climate benefits of that rule using a new set of SC–GHG estimates that incorporates recent research addressing recommendations of the National Academies[1007] in addition to using the interim SC–GHG estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*[1008] that the IWG recommended for use until updated estimates that address the National Academies' recommendations are available.

The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, *External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, which explains the methodology underlying the new set of estimates and was included as supplemental material to the RIA for the December 2022 Oil and Gas Supplemental Proposal.[1009] The response to comments document can be found in the docket for that action.

To ensure that the methodological updates adopted in the technical report are consistent with economic theory and reflect the latest science, the EPA also initiated an external peer review panel to conduct a high-quality review of the technical report, completed in May 2023. The peer reviewers commended the Agency on its development of the draft update, calling it a much-needed improvement in estimating the SC–GHG and a significant step toward addressing the National Academies' recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates were incorporated in the technical report to address peer reviewer recommendations. Complete information about the external peer review, including the peer reviewer selection process, the final report with individual recommendations from peer reviewers, and the EPA's response to each recommendation is available on

[1002] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

[1003] U.S. EPA. (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances." Washington, DC: U.S. EPA.

[1004] Ibid.

[1005] The EPA strives to base its analyses on the best available science and economics, consistent with its responsibilities, for example, under the Information Quality Act.

[1006] U.S. EPA. (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances." Washington, DC: U.S. EPA.

[1007] Ibid.

[1008] Interagency Working Group on Social Cost of Carbon (IWG). 2021 (February). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990. United States Government.

[1009] Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances," Docket ID No. EPA–HQ–OAR–2021–0317, November 2023.

the EPA's website.[1010] An overview of the methodological updates incorporated into the new SC–GHG estimates is provided in the RIA section 4.2. A more detailed explanation of each input and the modeling process is provided in the technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.[1011]

In addition to CO_2, these final rules are expected to reduce annual, national total emissions of NO_X and SO_2 and direct $PM_{2.5}$. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to annual average ambient $PM_{2.5}$ and would reduce the incidence of $PM_{2.5}$-attributable health effects. These final rules are also expected to reduce national ozone season NO_X emissions. In the presence of sunlight, NO_X and VOCs can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions in most locations reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs. The RIA estimates the health benefits of changes in $PM_{2.5}$ and ozone concentrations. The health effect endpoints, effect estimates, benefit unit-values, and how they were selected are described in the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD.[1012] Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized in section 4 of the RIA.

The following PV and EAV estimates reflect projected benefits over the 2024 to 2047 period, discounted to 2024 in 2019 dollars, for the analysis of the final rules. We monetize benefits of the final rules and evaluate other costs in part to enable a comparison of costs and benefits pursuant to E.O. 12866, but we recognize that there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified. The projected PV of monetized climate benefits is about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent.[1013] The projected PV of monetized health benefits is about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Combining the projected monetized climate and health benefits yields a total PV estimate of about $390 billion and EAV estimate of $21 billion.

At a 3 percent discount rate, these final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$. Thus, these final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at a 3 percent rate.

At a 7 percent discount rate, these final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$. Thus, these final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at a 7 percent rate.

The results presented in this section provide an incomplete overview of the effects of the final rules. The monetized climate benefits estimates do not include important benefits that we are unable to fully monetize due to data and modeling limitations. In addition, important health, welfare, and water quality benefits anticipated under these final rules are not quantified. We anticipate that taking non-monetized effects into account would show the total benefits of the final rules to be greater than this section reflects. Discussion of the non-monetized health, climate, welfare, and water quality benefits is found in section 4 of the RIA.

2. Net Benefits

The final rules are projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent. The final rules are also projected to reduce emissions of NO_X, SO_2 and direct $PM_{2.5}$ leading to national health benefits from $PM_{2.5}$ and ozone in most years, producing a projected PV of monetized health benefits of about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Thus, these final rules are expected to generate a PV of monetized benefits of $390 billion, with an EAV of $21 billion discounted at a 2 percent rate. The PV of the projected compliance costs are $19 billion, with an EAV of about $0.98 billion discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $370 billion and EAV of about $20 billion.

At a 3 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at 3 percent. The PV of the projected compliance costs are about $15 billion, with an EAV of $0.91 billion discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $360 billion and an EAV of about $19 billion.

At a 7 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at 7 percent. The PV of the projected compliance costs are about $7.5 billion,

[1010] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review*.

[1011] U.S. EPA (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances." Washington, DC: U.S. EPA.

[1012] U.S. EPA. (2023). *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*. Research Triangle Park, NC: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Health and Environmental Impact Division.

[1013] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with the EPA's updated estimates of the SC–CO_2. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC–CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A–4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC–CO_2. See section 4.2 of the RIA for more discussion.

with an EAV of $0.65 billion discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $320 billion and an EAV of about $19 billion.

See section 7 of the RIA for additional information on the estimated net benefits of these rules.

E. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

For this action, the analysis described in this section and in the RIA is presented for the purpose of providing the public with an analysis of potential EJ concerns associated with these rulemakings, consistent with E.O. 14096. This analysis did not inform the determinations made to support the final rules.

The EPA defines EJ as ''the just treatment and meaningful involvement of all people regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environment so that people: (i) Are fully protected from disproportionate and adverse human health and environmental effects (including risks) and hazards, including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers; and (ii) have equitable access to a healthy, sustainable, and resilient environment in which to live, play, work, learn, grow, worship, and engage in cultural and subsistence practices.'' [1014] In recognizing that particular communities of EJ concern often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

1. Analytical Considerations

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' [1015] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) Create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (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?'' [1016]

To address these questions in the context of these final rules, the EPA developed a unique analytical approach that considers the purpose and specifics of these rulemakings, as well as the nature of known and potential disproportionate and adverse exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential EJ characteristics (*e.g.*, residence of historically redlined areas), environmental impacts (*e.g.*, other ozone metrics), and more granular spatial resolutions (*e.g.*, neighborhood scale) that were not evaluated. Also due to data and resource limitations, we discuss climate EJ impacts of this action qualitatively (section 6.3 of the RIA).

For these rules, we employ two types of analysis to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analysis can inform whether there are potential EJ concerns for population groups of concern in the baseline (question 1).[1017] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns due to the implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3).

In section 6 of the RIA, we utilize the two types of analysis to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to populations of potential EJ concern (section 6.4); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, life expectancy, redlining, Tribal land, age, sex, educational attainment, and degree of linguistic isolation (section 6.5). It is important to note that due to the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes relative to the baseline concentrations in each modeled future year, these rules are expected to have a small impact on the distribution of exposures across each demographic group. Each of these analyses should be considered independently of each other as each was performed to answer separate questions and is associated with unique limitations and uncertainties.

a. Proximity Analyses

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local environmental stressors, such as local NO_2 and SO_2 emitted from affected sources in these final rules, traffic, or noise. The Agency has conducted a demographic analysis of the populations living near facilities impacted by these rules including 114 facilities for which the EPA is unaware of existing retirement plans by 2032, 23 facilities (a subset of the 114 facilities) with known retirement plans between 2033–2040, and 94 facilities (also a subset of the 114 facilities) without known retirement plans before 2040. The baseline analysis indicates that on average the populations living within 5 km and 10 km of 114 facilities impacted by the final rules without announced retirement by 2032 have a higher percentage of the population that is American Indian, below the Federal poverty level, and below two times the Federal poverty level than the national average. In addition, the population living within 50 kilometers of the same 114 facilities has a higher percentage of the population that is Black. Relating these results to EJ question 1, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by

[1014] *https://www.federalregister.gov/documents/2023/04/26/2023-08955/revitalizing-our-nations-commitment-to-environmental-justice-for-all.*

[1015] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[1016] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[1017] The baseline for proximity analyses is current population information, whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.*, 2023 and 2026).

the regulatory actions for certain population groups of concern in the baseline (question 1). However, as proximity to affected facilities does not capture variation in baseline exposures across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure impact. The full results of the demographic analysis can be found in RIA section 6.4. The methodology and the results of the demographic analysis for the final rules are presented in a technical report, *Analysis of Demographic Factors for Populations Living Near Coal-Fired Electric Generating Units (EGUs) for the Section 111 NSPS and Emissions Guidelines—Final,* available in the docket for these actions.

b. Exposure Analyses

While the exposure analyses can respond to all three EJ questions, correctly interpreting the results requires an understanding of several important caveats. First, recognizing the flexibility afforded to each state in implementing the final guidelines, the results below are based on analysis of several illustrative compliance scenarios which represent potential compliance outcomes in each state. This analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. It is also important to note that the potential emissions changes discussed below are relative to a projected baseline, and any localized decreases or increases are subject to the uncertainty of the baseline projections discussed in section 3.7 of the RIA. This uncertainty becomes increasingly relevant in later years in which baseline modeling projects substantial reductions in emissions relative to today. Furthermore, several additional caveats should be noted that are specific to the exposure analysis. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the NAAQS whereas the $PM_{2.5}$ metric is more similar to the long-term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state and fuel level emission data paired with facility-level baseline emissions and provided at a resolution of 12 square kilometers. Additionally, here we focus on air quality changes due to these rulemakings and infer post-policy ozone and $PM_{2.5}$ exposure burden impacts. Note, we discuss climate EJ impacts of these actions qualitatively (section 6.3 of the RIA).

Exposure analysis results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

These rules are also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$ and because NO_X is a precursor to ozone formation, reducing these emissions would impact human exposure. Quantitative ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions, so they are performed to evaluate potential disproportionate impacts of these rulemakings. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from the EPA's EJ technical guidance more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. As discussed in the RIA, our analysis indicates that baseline ozone and $PM_{2.5}$ concentration will decline substantially relative to today's levels for all demographic groups in all future modeled years, and these baseline levels of ozone and $PM_{2.5}$ can be considered to be relatively low. However, there are differences in exposure among demographic groups within these relatively low levels of baseline exposure. Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic populations, Asian populations, and those without a high school diploma may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian populations, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and unemployed populations may also experience disproportionately higher ozone concentrations than the reference group. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group. Therefore, also in response to question 1, there likely are potential EJ concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory actions for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications.

Relative to the low baseline levels of exposure modeled in future years for $PM_{2.5}$ and ozone, exposure analyses show that the final rules will result in modest but widespread reductions in $PM_{2.5}$ and ozone concentrations in virtually all areas of the country, although some limited areas may experience small increases in ozone concentrations relative to forecasted conditions without the rule. The extent of areas experiencing ozone increases varies among snapshot years. Due to the small magnitude of the exposure changes across population demographics associated with these rulemakings relative to the magnitude of the baseline disparities, we infer that post-policy EJ ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated compared to the baseline. Due to the very small magnitude of differences across demographic population post-policy impacts, we do not find evidence that disparities among communities with EJ concerns will be exacerbated or mitigated by the regulatory alternatives under consideration regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures for most demographic groups in the future years evaluated. In 2035, under the illustrative compliance scenarios analyzed, it is possible that Asian populations, Hispanic populations, and those linguistically isolated, and those living on Tribal land may experience a slight exacerbation of ozone exposure disparities at the national level (question 3), compared to baseline ozone levels. Additionally at the national level, those living on Tribal land may experience a slight exacerbation of ozone exposure disparities in 2040 and a slight mitigation of ozone exposure disparities in 2028 and 2030. At the state level, ozone exposure disparities may be either mitigated or exacerbated for certain demographic groups, also to a small degree. As discussed above, it is important to note that this analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

2. Outreach and Engagement

As part of the regulatory development process for these rulemakings, and consistent with directives set forth in multiple Executive Orders, the EPA conducted extensive outreach with interested parties including Tribal nations and communities with environmental justice concerns. This outreach allowed the EPA to gather information from a variety of viewpoints while also providing parties with an overview of the EPA's work to reduce GHG emissions from the power sector.

Prior to the May 2023 proposal, the EPA opened a public docket for pre-proposal input.[1018] The EPA continued to engage with interested parties by speaking on the EPA National Community Engagement call and the National Tribal Air Association Policy Update call in September 2022. Following publication of the proposal, the EPA hosted two informational webinars on June 6 and 7, 2023, specially targeted towards tribal environmental professionals, tribal nations, and communities with environmental justice concerns. The purpose of these webinars was to provide an overview of the proposal, information on how to effectively engage in the regulatory process and provide the EPA an opportunity to answer questions. The EPA held virtual public hearings on June 13, 14, and 15, 2023, that allowed the public an opportunity to present comments and information regarding the proposed rules.

The EPA recently finalized revisions to the subpart Ba implementing regulations requiring states to conduct meaningful engagement with pertinent stakeholders as part of the state plan development process. The EPA underscores the importance of this part of the state plan development process. For more detailed information on meaningful engagement, see section X.E.1.b.i of this preamble.

[1018] EPA–HQ–OAR–2022–0723.

F. Grid Reliability Considerations and Reliability-Related Mechanisms

1. Overview

The Federal Energy Regulatory Commission (FERC) is the federal agency with vested authority to ensure reliability of the bulk power system (16 U.S.C. 824o). FERC oversees and approves reliability standards that are developed by NERC and then become mandatory for all owners and operators of the bulk power system. Regional wholesale energy markets, like RTOs, ISOs, public service commissions, balancing authorities, and reliability coordinators all have reliability related responsibilities. The EPA's role under the CAA section 111 is to reduce emissions of dangerous air pollutants, including those emitted from the electric power sector. In doing so, it has a long, and exemplary history of ensuring its public-health-based emissions standards and guidelines that impact the power sector are sensitive to reliability-related issues and constructed in a manner that does not interfere with grid operators' responsibility to deliver reliable power. The EPA met with many entities with responsibility over the reliability of the bulk power system in crafting these final rules to make certain the rules will not impede their ability to ensure reliability of the bulk power system. This section outlines the array of modifications made in these final actions, outlined in section I.G of this preamble, that collectively help ensure that these final actions will not interfere with systems operators' ability to continue providing reliable power. Additional to this suite of adjustments, the EPA is introducing both a short-term reliability mechanism for emergency situations and a reliability assurance mechanism available for states to include in their state plans for additional flexibility. In response to the May 2023 proposed rule, the EPA received extensive comments regarding grid reliability and resource adequacy from balancing authorities, independent system operators and regional transmission organizations, state regulators, power companies, and other stakeholders. The EPA engaged with each of these group of commenters to garner a granular understanding of their reliability-related concerns. Additionally, the EPA met repeatedly with technical staff and Commissioners of FERC, DOE, NERC, and other reliability experts during the course of this rulemaking. At FERC's invitation, the EPA participated in FERC's Annual Reliability Technical Conference on November 9, 2023. Further, the EPA solicited additional comment on reliability-related mechanisms as part of the November 2023 supplemental proposed rule.

Comment: Several comments from grid operators raised the concern that the proposed rules have the potential to trigger material negative impacts to grid reliability. Concerns coalesced around the loss of firm dispatchable assets which they view as outpacing the development and interconnection of new assets that do not possess commensurate reliability attributes. Other commenters maintained that the proposals included adequate lead times for reliability planning, and that reliability attributes are currently sourced by a collection of assets, and as such a collection of future assets will be able to provide the requisite reliability attributes. Some commenters also asserted that the proposals would actually improve transparency around unit-specific decisions, which are often not communicated transparently with adequate notice, leading to a better reliability planning process.

Response: These final rules include a number of flexibilities and rule adjustments that will accommodate appropriate planning decisions by affected sources, system planners, and reliability authorities in a way that allows for the continued reliable operation of the electric grid. These final actions also include adjustments and improvements, with specific provisions related to compliance timing and system emergencies, that address reliability concerns. The rules do not interfere with ongoing efforts by key stakeholders to appropriately plan for an evolving electric system. The EPA agrees that transparency around unit-specific planning is of paramount importance to enabling systems operators advanced notice to plan for continued reliable bulk power operations.

The EPA initiated follow-up conversations with all balancing authorities and systems operators that submitted public comments to ensure a granular and thorough understanding of all reliability-related concerns raised in response to the proposed rules. In addition, the EPA solicited additional comment on reliability related mechanisms in the supplemental proposal issued in November 2023. The EPA examined the record carefully and responded with a suite of changes to the proposal that, though not always explicitly directed at addressing concerns raised with respect to reliability, nonetheless collectively help ensure EPA's rules will not interfere with grid operators' responsibilities to provide reliable power.

As discussed earlier in this preamble, the EPA is finalizing several adjustments to provisions in the proposed rules that address reliability concerns and ensure that these rules provide adequate flexibilities and assurance mechanisms that allow grid operators to continue to fulfill their responsibilities to maintain the reliability of the bulk-power system. These adjustments include restructuring the subcategories for coal-fired steam generating EGUs: the EPA is not finalizing the proposed imminent or near term subcategory structure which should provide states with a wider planning latitude, and units with cease operations dates prior to January 1, 2032 are not regulated by this final rule. Importantly, the compliance timeline for installing CCS in the long-term subcategory has been extended by an additional 2 years. The EPA is not finalizing the 30 percent hydrogen co-firing BSER for the intermediate subcategory for new combustion turbines. These changes facilitate reliability planning and operations by providing more lead time for CCS installation-related compliance. The adjusted scope of these actions also provides additional time for the EPA to consult with a broad range of stakeholders, including grid operators, to deliberate and determine the best way to address emissions from existing gas turbines while respecting their contribution to electric reliability in the foreseeable future. In addition to these adjustments, as detailed in section X.D of this preamble, the EPA is offering states a suite of voluntary compliance flexibilities that could be used to address reliability concerns. These compliance flexibilities include clarifying the circumstances under which it may be appropriate for states to employ RULOF to establish source specific standards of performance and compliance schedules for affected EGUs to address reliability, allowing emission averaging, trading, and unit-specific mass-based compliance mechanisms for certain subcategories—provided that they achieve an equivalent level of emission reduction consistent with the application of individual rate-based standards of performance, and, for certain mechanisms, that they include a backstop emission rate, and offering a compliance date extension for affected new and existing EGUs that encounter unanticipated delays with control technology implementation.

The EPA believes the adjustments made to the final rules outlined above are sufficient to ensure the rules can be implemented without impairing the ability of grid operators to deliver reliable power. The EPA is nonetheless finalizing additional reliability-related instruments to provide further certainty that implementation of these final rules will not intrude on grid operators' ability to ensure reliability. The short-term reliability mechanism is available for both new and existing units and is designed to provide additional flexibility through an alternative compliance strategy during acute system emergencies that threaten reliability. The reliability assurance mechanism will be available for existing units that intend to cease operating, but, for unforeseen reasons, need to temporarily remain online to support reliability beyond the planned cease operation date. This reliability assurance mechanism, which requires a specific and adequate showing of reliability need that is satisfactory to the EPA, is intended for circumstances where there is insufficient time to complete a state plan revision, and it is limited to the amount of time substantiated, which may not exceed 1 year. The EPA intends to consult with FERC for advice on applications of reliability need that exceed 6 months. These instruments will be presumptively approvable, provided they meet the requirements defined in these emission guidelines, if states choose to incorporate them into their plans.

Comment: Commenters from industry and grid operators expressed support for the inclusion of a requirement that states include in their state plans a demonstration of consultation with all relevant reliability authorities to facilitate planning. Other commenters asserted that the proposals included sufficient coordination with reliability authorities, through the Initial Reporting Milestone Status Report requirements.

Response: The EPA agrees that planning for reliability is critically important. Indeed, all stakeholders generally agree that effective planning is essential to ensuring electric reliability is maintained.[1019] State planning, including coordination and transparency across jurisdictions, is particularly important given that state plans in one jurisdiction can impact the reliability and resource adequacy of other system operators. The EPA is finalizing, as part of the state plan development process, that states are required to conduct meaningful engagement with stakeholders. As part of this required meaningful engagement, states are strongly encouraged to consult with the relevant balancing authorities and reliability coordinators for their affected sources and to share available unit-specific requirements and compliance information in a timely fashion. Sharing regulatory requirements and unit-specific compliance information with balancing authorities and reliability coordinators in a timely manner will promote early and informed reliability planning. Strong system-planning processes of utility transmission companies and RTOs are among the most important tools to assure that reliability will not be adversely affected by regulations.[1020] [1021] A robust planning process that recognizes the different roles of states and their relevant balancing authorities, transmission planners, and reliability coordinators should help to identify potential resource adequacy or reliability issues early in the state planning process. States will also be able to address reliability-related issues through a revision in their state plan, including to address issues that were not foreseen during the state planning process.

In addition to these measures, DOE has authority pursuant to section 202(c) of the Federal Power Act to, on its own motion or by request, order, among other things, the temporary generation of electricity from particular sources in certain emergency conditions, including during events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements. Such orders may be issued for 90 days and may be extended in 90-day increments after consultation with EPA. DOE has historically issued section 202(c) orders at the request of electric generators and grid operators such as RTOs in order to enable the supply of additional generation in times of expected emergency-related generation shortfalls.

Congress provided section 202(c) as the primary mechanism to ensure that when generation is needed to meet an emergency, environmental protections will not prevent a source from meeting that need. To date, section 202(c) has worked well, allowing, for example,

[1019] "Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023," Susan Tierney, Analysis Group, November 7, 2023.

[1020] "Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023," Susan Tierney, November 7, 2023.

[1021] "Modernizing Governance: Key to Electric Grid Reliability", Kleinman Center for Energy Policy, University of Pennsylvania, March 2024.

additional generation to come online to meet demand in the California Independent System Operator and PJM territories in 2022.[1022] Section 202(c) has also been used to allow generators to remain online pending completion of infrastructure needed to facilitate reliable replacement of those generators. The EPA continues to believe that section 202(c) is an effective mechanism for meeting the purpose of ensuring that all physically available generation will be available as needed to meet an emergency situation, regardless of environmental regulatory constraints. Given the heightened concerns about reliability expressed by commenters in the context of this rule and ongoing changes in the electricity sector, however, this final action includes an additional supplemental short-term reliability mechanism that states may elect to include in their state plans. States that adopt this mechanism could make it available for sources to use without needing action by DOE under section 202(c). Of course, section 202(c) would continue to be available for sources subject to this rule for emergency situations where EPA's short-term reliability mechanism would not apply.

Many electric reliability and bulk-power system authorities, including FERC and the regulated wholesale markets, are actively engaged in activities to ensure the reliability of the transmission grid, while paying careful attention to the changing resource mix and the ongoing trends in the power sector.[1023] [1024] There are multiple agencies and entities that have some authority and responsibility to ensure electric reliability. These include state utility commissions, balancing authorities, reliability coordinators, DOE, FERC, and NERC. The EPA's central mission is to protect human health and the environment and the EPA does not have direct authority or responsibility to ensure electric reliability. Still, the EPA believes reliability of the bulk power system is of paramount importance, and has included additional measures in these final actions that are delineated throughout this section, evaluated the resource adequacy implications in the final TSD, *Resource Adequacy Analysis*, and conducted capacity expansion modeling of the final rules in a manner that takes into account resource adequacy needs. Additionally, the EPA performed a variety of other sensitivity analyses including an examination of higher electricity demand (many areas are reporting accelerated load growth forecasts due to data centers, increased manufacturing, crypto currency, electrification and other factors) and the impact of the EPA's additional regulatory actions affecting the power sector. These sensitivity analyses indicate that, in the context of higher demand and other pending power sector rules, the industry has available pathways to comply with this rule that respect NERC reliability considerations and constraints. These results are detailed in the technical memoranda in the docket titled, *IPM Sensitivity Runs* and *Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG, and MATS*.

The EPA has carefully examined all comments related to reliability that were submitted during the public comment period for the proposal and for the supplemental notice. The Agency has engaged in dialogue with each of the balancing authorities regarding the content of their submitted comments. Based on this extensive engagement and consultation, the Agency's analysis of the impacts of these rules, and the various features of this rule that will work in tandem to ensure the standards and emission guidelines finalized here are achievable and can respond to future reliability and resource adequacy needs, the EPA has concluded these final rules will not interfere with grid operators' ability to continue delivering reliable power.

The EPA received a range of opinions during the comment process, and also during FERC's Annual Reliability Conference, some of which expressed that the proposed rule could provide a net benefit to reliability planning given the enhanced visibility into unit-specific compliance plans.[1025] This section discusses the additional compliance flexibilities and reliability instruments that have been included in these final rules.

The EPA has carefully considered the importance of reliability of the bulk-power system in developing these final rules. Stakeholders have recognized the EPA's long and successful history of ensuring its power sector rules are crafted to deliver significant public health benefits while not impairing the ability of grid operators to ensure reliable power.[1026] The entities responsible for ensuring reliability, which encompass electric utilities, RTOs and ISOs, reliability coordinators, other grid operators, utility and non-utility energy companies, and Federal and state regulators, have also historically met challenges in navigating power sector environmental obligations while maintaining reliability.[1027]

2. Compliance Flexibilities for New and Existing Affected EGUs

These final rules include three key compliance flexibilities for new and existing sources and reliability coordinators so that they can continue to plan for the reliable operation of the electric system; RULOF, emissions averaging and trading, and compliance extensions of up to 1 year for units installing control technology. As discussed in section X.C.2 of this preamble, states may use the RULOF provisions to address circumstances in which reliability or resource adequacy is a concern. Use of RULOF may be appropriate where reliability or resource adequacy considerations for a particular EGU are fundamentally different from those considered when developing these emission guidelines, which may make it unreasonable for an affected EGU to comply with a standard of performance by the prescribed date. Under these circumstances, the state may choose to particularize the compliance obligations for the affected EGU in order to address the reliability or resource adequacy concern. As explained in section X.C.2, the EPA believes any adjustments that are needed will take the form of different compliance timelines. RULOF is relevant at the stage of establishing standards of performance and compliance schedules to affected EGUs as a state plan is being developed or revised.

States have the ability to use emission averaging or trading, as well as unit-specific mass-based compliance, as described in section X.D of this preamble, which may also provide reliability-related benefits. The use of these alternative compliance flexibilities is not required, but states may employ these flexibilities, provided they demonstrate that their programs achieve an equivalent level of emission reduction with unit-specific application

[1022] DOE. DOE's Use of Federal Power Act Emergency Authority. *https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority*.

[1023] See Resource Adequacy Analysis document for further analysis and exploration of these important elements.

[1025] "In the current environment, grid operators are unsure about when resources may retire, increasing uncertainty and making planning harder. The proposed rules have long timelines for enactment, giving states, utilities, and grid operators plenty of time to plan for the transition." From "Prepared Statement of Ric O'Connell Executive Director, GridLab," Testimony before FERC Annual Reliability Technical Conference on November 9, 2023.

[1026] "Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants," Susan Tierney, November 7, 2023.

[1027] "Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability," Susan Tierney, May 2014.

of rate-based standards of performance and apply requirements relevant to the particular flexibility, as specified in section X.D. These compliance flexibilities are voluntary, and states may choose whether to allow their use in state plans, subject to certain conditions. However, states may find that the reliability-specific adjustments discussed below provide sufficient flexibility in lieu of the mechanisms described in section X.D.

States may incorporate into their state plans a mechanism that allows compliance date extensions up to 1 year for an existing affected EGU that is in the process of installing a control technology to meet its standard of performance in the state plan, under specific circumstances, a detailed discussion can be found in section X.C.1.d of this document. As discussed in section VIII.N of this document, the Administrator may provide a similar extension for new combustion turbines. The state or Administrator may allow the extension of the compliance date if the source demonstrates a delay in the construction or implementation of the control technology resulting from causes that are entirely outside the owner or operator's control. These may include delays in obtaining a final construction permit, after a timely and complete application, or delays due to documented supply chain issues; for example, a backlog for step-up transformer equipment. This compliance date extension is not expressly offered for reliability purposes, but rather as a flexibility to account for unforeseen and uncontrollable lags in construction or implementation of control technology to meet the unit's standard of performance, in instances where a source can demonstrate efforts to comply by the required timeframes as part of these final actions, including evidence that it took the necessary steps to comply with sufficient lead time to meet the compliance schedule absent unusual problems, and that those problems are entirely outside the source's control and the source's actions or inactions did not contribute to the delay. This potential extension can help ensure that sufficient capacity is available by providing additional time for an affected EGU to operate for a specific amount of time while it resolves delays related to installation of pollution controls.

If the owner/operator of an affected EGU encounters a delay outside of the owner or operator's control, and which prevents the source from meeting its compliance obligations, the affected EGU must follow the procedures outlined in the state plan for documenting the basis for the extension.[1028] Any delay in implementation that will necessitate a compliance date extension of more than 1 year must be done through a state plan revision to adjust the compliance schedule using RULOF as a basis. See section X.C.2 of this preamble for information on RULOF.

A similar 1-year compliance date extension flexibility for units implementing control technologies that encounter a delay outside of the owner or operator's control which prevents the source from meeting compliance obligations is also available to certain new sources, which are directly regulated by the EPA. This is described in section VIII.N of this preamble.

3. Reliability Mechanisms

While the EPA believes the significant structural adjustments and compliance flexibilities that are discussed above are adequate to ensure that the implementation of these final rules does not interfere with systems operators' ability to ensure electric reliability, the EPA is also finalizing two reliability-related mechanisms as additional safeguards. These mechanisms include a short-term reliability mechanism for unexpected and short-duration emergency events, and a reliability assurance mechanism for units with retirement dates that are enforceable in the state plan, provided there is a documented and verified reliability concern. The EPA notes that these mechanisms must be included in the state plan to be utilized by the owners/operators of existing affected EGUs subject to requirements in the state plan. Sections XII.3.a, and XII.3.b of this preamble describe presumptively approvable methodologies for incorporating these mechanisms into a state plan.

a. Short-Term Reliability Mechanism

Comment: Multiple commenters requested an explicit short-term mechanism which could accommodate emergency situations and provide additional flexibility to affected sources. Commenters requested that the mechanism include additional rule flexibilities that could potentially be used during emergency conditions that would help reliability authorities avert a load shed event. A mechanism would function as an additional automated flexibility measure with a clearly articulated emergency provision for affected sources to respond to short-duration emergency grid situations. Some commenters requested a mechanism that is distinct from the process established by DOE's emergency authority under the Federal Power Act (section 202(c)), whereby DOE is required by the terms of section 202(c) to issue orders tailored to best meet particularized emergency circumstances.[1029] Other commenters highlighted the numerous rule flexibilities that were designed to accommodate reliability concerns and emergency conditions and indicated that the EPA's rule need not overly accommodate reliability and resource adequacy concerns since the primary burden for developing solutions falls to industry, grid operators, reliability coordinators, state planners, and other stakeholders. These commenters indicated that it is important to consider any trade-offs with additional flexibility measures, in particular any trade-offs with emissions implications.

Response: The EPA agrees with the latter commenters and expects that the broader adjustments in the final rules, in addition to the compliance flexibilities offered to states in section X.D of this document, along with DOE's pre-existing section 202(c) authority, are sufficient to enable an affected unit to respond to emergencies as needed and still comply with the annual requirements of these actions. As an additional safeguard measure, the EPA is finalizing a short-term reliability mechanism to assure that these final actions will not interfere with grid operators' ability to ensure electric reliability. More specifically, the EPA has determined that some accommodation during grid emergencies, which are rare, is warranted in order to provide some additional flexibility to help system planners, affected sources, state regulators, and reliability authorities meet demand and avert load shed when such emergencies occur. The EPA believes this additional flexibility is warranted, given the projected increase in extreme weather events exacerbated by climate change.

A short-term reliability mechanism for new sources is included in the final NSPS. Similarly, a short-term mechanism is offered to states to include in state plans for use with existing sources during specific and defined periods of time where the grid is under extreme strain. The short-term reliability mechanism is linked to specific conditions under which the system operators may not have

[1028] Assuming the affected EGU is in a state that has included the extension mechanism in its approved plan.

[1029] *https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.*

sufficient available generation to call upon to meet electric demand, and various reliability authorities have issued emergency alerts to rectify the situation. These emergency alerts are most often associated with extreme weather events where electric demand increases and there are often unexpected transmission and generation outages. Recent examples of short-term emergency alert conditions include Winter Storm Uri in 2021 and Winter Storm Elliot in 2022, both of which included unanticipated generator outages and triggered emergency grid operations. The EPA expects that the broader adjustments to the final rules, in combination with the compliance flexibilities described in section XII.F.2 of this document, are sufficient to enable an affected unit to respond to grid emergencies as needed and still comply with the annual requirements of these actions. Nonetheless, the EPA is finalizing this short-term reliability mechanism, available to states to include at their discretion, to provide an additional layer of assurance that these final actions will not interfere with the grid operator's ability to ensure electric reliability.

A short-term reliability mechanism is included for new sources in the final NSPS, and additionally offered to states to include in state plans for existing sources. The mechanism provides affected sources additional flexibility during rare and extreme emergency events, when all available generators are called upon to meet electric demand. For new sources, the mechanism allows sources to calculate applicability and compliance without using the emissions and operational data produced during these discrete events, with appropriate documentation.[1030] For existing sources, the mechanism allows sources to use the baseline emission rate during these discrete events, also with appropriate documentation.[1031]

The mechanism is only applicable during an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor, which requires plans and sets procedures for reliability entities to help avert disruptions in electric service during emergency conditions.[1032] The NERC reliability standard articulates roles and responsibilities, defines notification processes for reliability coordinators and operators, requires a plan for grid management practices, and specifies a compliance monitoring process. Notably, the standard defines three levels of Energy Emergency Alerts (EEA) that guide reliability coordinators during energy emergencies and assist with communicating information across the system and with the public to avert potential disruptions:

• *EEA–1:* All available generation resources in use—The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.

• *EEA–2:* Load management procedures in effect—The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority. An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies. An energy deficient Balancing Authority is still able to maintain its minimum Contingency Reserve requirement.

• *EEA–3:* Firm Load interruption is imminent or in progress—The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

The alerts are typically issued in reaction to emergencies as they develop, are generally rare, and most often have been issued during extreme weather events, such as hurricanes, cold weather events, and heatwaves. The most concerning alert is EEA–3, where interruption of electric service through controlled load shed is imminent for some areas, although load shed does not necessarily occur under every EEA–3 declaration. According to NERC, 25 EEA–3s were declared in 2022, an increase of 15 EEA–3 declarations over 2021. Nine of the EEA–3 declarations in 2022 included shedding of firm load. While the number of declarations increased from 2021, the amount of load that was shed during the 2022 events was less than 10 percent of the previous year.[1033] All of the EEA–3 declarations in 2022 were related to extreme weather impacts, according to NERC.[1034]

Other emergency events (EEA–1 and EEA–2) are more frequent, although also relatively rare, based upon recent data. Data for the largest ISOs and RTOs indicate that EEA–1 and EEA–2 can occur several times over a year, for relatively brief periods in most instances, in response to developing reliability emergencies.[1035] Across the country, reliability coordinators (RCs) are charged by NERC to implement reliability standards and issue EEAs.[1036] The RCs monitor, track, and issue alerts according to the NERC alert protocol. This data is also generally supposed to be publicly available on each reliability coordinator's website, which documents the frequency and duration of emergency alerts. However, while there are requirements to report events where EEA–3 was declared to NERC [1037] and NERC publicly tracks use of EEA–3,[1038] EEA–1 events are the least likely to be documented consistently, for example, there is no similar publicly available tracking and reporting for use of EEA–1 alerts in a centralized and consistent manner.

Energy Emergency Alerts also have an important geographic and/or regional component, since most emergencies affect a particular geographic zone, and hence a smaller number of generators are subject to the alert in most instances.

[1030] The performance standard shall be the Phase I standard for the affected new source under the NSPS.

[1031] The baseline emission rate for existing sources is the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**.

[1032] NERC Reliability Standards, *https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx*, and NERC Emergency Preparedness and Operations (Reliability Standard EOP–011–2). *https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-2.pdf*.

[1033] 2023 State of Reliability Technical Assessment, NERC. *https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf*.

[1034] Ibid.

[1035] Since 2021, ERCOT issued two EEA–1 events, two EEA–2 events, and one EEA–3 event (all for events occurring over an 8-hour period one day in 2021, and for 1 hour in 2023). In SPP, since 2021, there were eight EEA–1 events, five EEA–2 events, and two EEA–3 events (occurring over 5 days). The EEA–1 and EEA–2 events lasted between 1 and 19 hours. In MISO, there was a 2-day event in 2021 that resulted in an EEA magnitude 1, 2, or 3 alert through the day and into the next day. One EEA–1 event in 2022 lasted for a half hour and an EEA–2 event for 3 hours. In 2023, there was an EEA–2 event for 9.5 hours. In PJM, no alerts were issued in 2021. In 2022, roughly a dozen alerts were issued. Some lasted minutes, while others lasted half a day. One event stretched for 3 days. There were two alerts issued in 2023, lasting roughly 3 and 1 hours each. While this data is not comprehensive, it is indicative of the frequency and duration of emergency events that fall under the NERC reliability standard alert process. See: ERCOT Market Notices, SPP Historical Advisories and Alerts, *https://www.oasis.oati.com/SWPP/*; MISO Maximum Generation Emergency Declarations (2023), *https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf*; and MISO Maximum Generation Emergency Declarations (2023), *https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf*. See also PJM Emergency Procedures and Postings, *https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf*.

[1036] NERC Organization Certification (January 2024). *https://www.nerc.com/pa/comp/Pages/Registration.aspx*.

[1037] *https://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/M-11_Energy_Emergency_Alerts.pdf*.

[1038] *https://www.nerc.com/pa/RAPA/ri/Pages/EEA2andEEA3.aspx*.

During extreme and large-scale weather events, the alerts often cover a much broader geographic area, such as when Winter Storm Elliott impacted two-thirds of the lower 48 states and rapidly intensified into a bomb cyclone in December 2022. Many areas declared EEAs, and four states experienced operator-controlled load shed and 2.1 million customers experienced power outages.[1039] When these events occur, a much larger group of affected sources would be potentially covered.[1040] It should be noted that issuance of EEA's is not just dependent on a generator's availability, but also, generation deliverability, as transmission constraints due to operational conditions or planned maintenance activities can lead to issuance of EEA's that help ensure system stability and reliability.

The EPA's assessment is that these alerts generally occur infrequently, only rarely persist for as long as several days, and are indicative of a grid under strain. When the alerts are more prolonged, lasting for several days, they are generally dictated by persistent extreme weather with widespread impacts and a higher probability of load shed. The short-term reliability mechanism offers sources that come under a documented level 2 and or 3 EEA, combined with a documented request from the balancing authority to deviate from its scheduled operations, for example, by increasing output in response to the alert. In other words, only the specific units called upon, or otherwise instructed to increase output beyond the planned day-ahead or other near-term expected output during an EEA level 2 or 3 event are eligible for this flexibility, with proper documentation.

For new sources, the emissions and/or generation data will not be counted when determining applicability and the use of the sources' Phase 1 standard of performance may be used for compliance determinations through the duration of these events, as long as appropriate documentation is provided. For existing sources, states may choose to temporarily apply an alternative standard of performance, or a unit's baseline emission performance rate, when demonstrating compliance with the final standards, with appropriate documentation. It should be emphasized that these final emission guidelines require compliance with the standards of performance on an annual basis (or rolling annual average for new sources), as opposed to a shorter period such as hourly, daily, or monthly. This relatively long compliance period provides significant flexibility for sources that face circumstances whereby their emission performance may change temporarily due to various factors, including in response to grid emergency conditions. Nonetheless, this mechanism is included in these final rules to ensure that affected sources have the additional flexibility needed to meet demand during emergency conditions.[1041]

The short-term reliability mechanism references EEA–2 and EEA–3 for several reasons. First, balancing authorities and grid operators do not necessarily have to take action under EEA–1 conditions, such as calling on interruptible loads. As such, there is much less cost or inconvenience to declaring EEA–1, as a general matter, and EEA–2 and EEA–3 events are more aligned with events that are rare or truly represent emergency conditions. Second, EEA–1 events are a preparatory step in anticipation of potentially worsening conditions, as opposed to an indicator of imminent load-shed. Thus, under EEA–1, balancing authorities and grid operators do not generally take actions such as calling for voluntary demand reduction or calling on interruptible loads, and reliability coordinators are afforded more discretion for declaring an EEA–1. As such, there is much less cost or inconvenience to declaring EEA–1, as a general matter, and providing operational or cost relief under EEA–1 could create an incentive to deploy it more routinely. In addition, waiving significant regulatory requirements before taking actions such as calling for voluntary demand reductions or calling upon contractually arranged interruptible loads would not be commensurate to the significance of the various response actions. Third, reliability coordinators are afforded more discretion for declaring an EEA–1, and thus may have a potential incentive to deploy it more routinely if there is some operational or cost relief associated with it. And lastly, the reporting of EEA–1 is not consistent throughout the country, and there is some degree of opaqueness associated with the frequency and duration of EEA–1 events, thus making it a less robust mechanism threshold for purposes of aligning it with the requirements of this final action. For these reasons, the EPA believes that EEA–2 and EEA–3 are the appropriate threshold for inclusion in the short-term reliability mechanism and better represent rare or truly emergency conditions in which providing a limited exemption from a significant environmental requirement is justifiable.

Thus, the EPA believes that the selection of EEA–2 and EEA–3 are aligned with the conditions envisioned where an affected source might need temporarily relief, in order to offer reliability coordinators and balancing authorities the flexibility needed during emergency events to maintain reliability. In addition, as explained earlier, DOE's 202(c) authority is an additional mechanism that can be deployed under certain emergency conditions, which may occur outside any EEA–2 or EEA–3 event. These tools, either individually or in combination, help provide additional assurance that sources and reliability coordinators can continue to maintain a reliable system.

The mechanism is available to states to include in their state plans in an explicit manner, which will allow additional flexibility to sources in those states during short-term reliability emergencies. Inclusion of the reliability mechanism in a state plan must be part of the public comment process that each state must undertake. The comment process will afford full notice and the opportunity for the public comment, and the state plan will need to specify alternative performance standards for each specific affected source during these events (as defined in this section). The state plan must clearly indicate the specific parameters of emergency alerts cited as part of this mechanism, the relevant reliability coordinators that are authorized to issue the alerts in the state, and the compliance entities who are affected by this action (*i.e.,* affected sources). These sources must provide documentation of emergencies, as indicated in this section. The documentation must include evidence of the alert from the issuing entity, duration of the alert, and requests by reliability entities to sources to increase output in response to the emergency. The source must supply this

[1039] 2023 State of Reliability Technical Assessment, NERC. *https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf.*

[1040] For example, the entire footprint of SPP *currently* includes roughly 50 individual coal-steam units, reflecting roughly 19 GW of capacity.

[1040] For PJM, there are *currently* roughly 65 individual coal-steam units with total capacity of roughly 30 GW, which could potentially be covered by a regionwide alert. These estimates are considerably lower when known and committed coal-steam retirements are excluded. Within the PJM footprint, there are 27 control areas or transmission zones where emergency procedures are applied.

[1041] For example, units with installed CCS technology may be called upon to run at full capacity (*i.e.,* without the parasitic load of the carbon capture equipment). The EPA does not expect this to be a typical response as units are economically disincentivized to shut off or bypass control equipment given the tax credit incentives in IRC section 45Q.

information to the state regulatory entities and to the EPA when demonstrating compliance with the annual performance standards. This demonstration will indicate the discrete periods where the alternative standards or emission rates were in place, coinciding with the emergency alerts.

The calculation of the emission rate for an affected source in a state that adopts the short-term reliability mechanism must adhere to the following during potential emergency alerts:

- When demonstrating annual compliance with the standard of performance, the existing affected source may apply its baseline emission rate in lieu of its standard of performance for the hours of operation that correspond to the duration of the alert; and
- The existing affected EGU would demonstrate compliance based on application of its baseline emission performance rate standard of performance for the documented hours it operated under a revised schedule due to an EEA 2 or 3.
- For new sources, the EGU would demonstrate compliance based on application of its phase 1 performance standard for the documented hours it operated under a revised schedule due to an EEA 2 or 3. with the same documentation listed above.

Supplemental reporting, recordkeeping and documentation required:

- Documentation that the EEA was in effect from the entity issuing the alert, along with documentation of the exact duration of the event;[1042]
- Documentation from the entity issuing the alert that the EEA included the affected source/region where the unit was located; and
- Documentation that the source was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside of its scheduled dispatch during emergency conditions from a reliability coordinator, balancing authority, or ISO/RTO.

b. Reliability Assurance Mechanism

The EPA gave considerable attention and thought to comments from all stakeholders concerning potential reliability-related considerations. As noted earlier, the EPA engaged in extensive stakeholder outreach and provided additional opportunity for public comment as part of the supplemental notice for small businesses, since similar reliability-related concerns were raised. This section provides additional background, as well as approvable language, for a reliability assurance mechanism that states have the option to incorporate into their state plans.

Comment: Some commenters cautioned that EPA rules could exacerbate an ongoing concern that firm, dispatchable assets are exiting the grid at a faster pace than new capacity can be deployed and that most new electric generating capacity does not provide the equivalent reliability attributes as the capacity being retired. Several commenters provided examples where units with publicly announced retirement dates were delayed by reliability entities and coordinators due, in part, to the potential for energy shortfalls that might increase reliability risks in the ISO. Many commenters cited findings from NERC that highlighted the potential for capacity shortfalls, some of which are already in effect in some areas. Other commenters asserted that there is no need for a reliability assurance mechanism given the sufficient lead times in the proposal and the various flexibilities already provided. Some commenters included analysis that showed resource adequacy shortfalls over the forecasted time horizon were limited and manageable under the proposal.

Response: The EPA believes that the provisions in these final actions are sufficient to accommodate installation of pollution controls and reliability planning. The EPA has further articulated the use of RULOF, which can be deployed under the state planning and revision processes, for specific circumstances related to reliability. The EPA is also finalizing compliance flexibilities that can address delays to the installation or permitting of control technologies or associated infrastructure that are beyond the control of the EGU owner/operator. The EPA acknowledges that isolated issues could unfold over the course of the implementation timeline that could not have been foreseen during the planning process and that may require units to remain online beyond their planned cease operation dates to maintain reliability.

The EPA does not agree that the final rule will result in long-term adverse reliability impacts.[1043] [1044] Nevertheless, as an added safeguard, the EPA is finalizing a reliability assurance mechanism for existing affected sources that have committed to cease operation but, for unforeseen reasons, need to temporarily remain online to support reliability for a discrete amount of time beyond their planned date to cease operations. The primary mechanism to address reliability-related issues for units with cease operations dates is through the state plan revision process. This reliability assurance mechanism is designed to enable extensions for cease operation dates when there is insufficient time to complete a state plan revision. Under this reliability assurance mechanism, which can only be accessed if included in a state plan, units could obtain up to a 1-year extension of a cease operation date. If a state decides to include the mechanism in its state plan, then the mechanism must be disclosed during the public comment process that states must undertake. Under this reliability assurance mechanism, units may obtain extensions only for the amount of time substantiated through their applications and approved by the appropriate EPA Regional Administrator. For extension requests greater than 6 months, EPA will seek the advice of FERC in these cases and therefore applications must be submitted to FERC, as well as to the appropriate EPA Regional Administrator. The date from which an extension can be given is the enforceable date in the state plan, including any cease operation dates in state plans that are prior to January 1, 2032.

These provisions are similar in part to a reliability-related flexibility provided by the EPA for the MATS rule finalized in December 2011. On December 16, 2011, the EPA issued a memorandum[1045] outlining an Enforcement Response Policy whereby affected sources enter into a CAA section 113(a) administrative order for up to 1 year for narrow circumstances including when the deactivation of a unit or delay in installation of controls due to factors beyond the owner's/operator's control could have an adverse, localized impact on electric reliability. Under MATS, affected sources were required to come into compliance with standards within 3 years of the effective date. The EPA believed flexibility was warranted given potential constraints around the availability of control equipment and associated skilled workforce for all affected sources within the compliance window. While a 1-year extension as

[1042] *https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-2.pdf.*

[1043] "Bulk System Reliability for Tomorrow's Grid" The Brattle Group, December 20, 2023.

[1044] "The Future of Resource Adequacy" The Department of Energy, April 2024.

[1045] *https://www.epa.gov/sites/default/files/documents/mats-erp.pdf.*

part of CAA section 112(i)(3)(B) was broadly available to affected sources, additional time through an administrative order was limited to units that were demonstrated to be critical for reliability purposes under the Enforcement Response Policy.[1046] FERC's role in this process, which was developed with extensive stakeholder input,[1047] was to assess the submitted request to ensure any application was adequately substantiated with respect to its reliability-related claims. While several affected EGUs requested and were granted a 1-year CAA section 112(i)(3)(B) compliance extension by their permitting authority, OECA only issued five administrative orders in connection to the Enforcement Response Policy.[1048] These orders relied upon a FERC review of the reliability risks associated with the loss of specific units, following the accompanying FERC policy memorandum guidance.[1049] The 2012 MATS Final Rule was ultimately implemented over the 2015–2016 timeframe without challenges to grid reliability.

Given the array of adjustments made to the rule explained above, and the ability of states to address unanticipated changes in circumstances through the state plan revision process, the EPA does not anticipate that this mechanism, if included by states in the planning process, will be heavily utilized. This mechanism provides an assurance to system planners and affected sources, which can provide additional time for the state to execute a state plan revision, if needed. For states choosing to include this option in their state plans, the reliability assurance mechanism can provide units up to a 1-year extension of the scheduled cease operation date without a state plan revision, provided the reliability need is adequately justified and the extension is limited to the time for which the reliability need is demonstrated. This mechanism can accommodate situations when, with little notice, the relevant reliability authority determines that an EGU scheduled to cease operations is needed beyond that date, in order to maintain reliability during the 12 months leading up to or after the EGU is scheduled to retire. For potential situations in which system planners, affected sources, and reliability authorities identify a reliability concern, including a potential resource adequacy shortfall and an associated demonstration of increased loss of load expectation, more than one year in advance, this approach allows for the time needed for states to undertake a state plan revision process. The EPA recognizes that successful reliability planning involves many stakeholders and is a complex long-term process. For this reason, the EPA is encouraging states to consult electric reliability authorities during the state plan process, as part of the requirements under Meaningful Engagement (see section X.E.1.b.i of this document). The EPA acknowledges that there may be isolated instances in which the deactivation or retirement of a unit could have impacts on the electric grid in the future that cannot be predicted or planned for with specificity during the state planning process, wherein all anticipated reliability-related issues would be analyzed and addressed. This mechanism is not intended for use with units encountering unforeseen delays in installation of control technologies, as such issues are addressed through compliance flexibilities discussed in section XII.F.2, or for units subject to an obligation to operate that is not based on the reliability criteria included here.

To ensure that reliability claims, following the specific requirements delineated below, submitted through this mechanism are sufficiently well documented, the EPA is requiring that the unit's relevant reliability Planning Authority(ies) certify that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested. Additionally, the EPA intends to seek the advice of FERC, the Federal agency with authority to oversee the reliability of the bulk-power system, to incorporate a review of applications for this mechanism that request more than 6 months of additional operating time beyond the existing date by which the unit is scheduled to cease operations to resolve a reliability issue. Additional operating time is available for up to 12 months from the unit's cease operation date through this mechanism. Any relief request exceeding 12 months would need to be addressed through the state plan revision process outlined in section X.E.3. In determining whether to grant a request under this mechanism, the EPA will assess whether the associated Planning Authority's reliability analysis identifies and supports, in a detailed and reasoned fashion, anticipated noncompliance with a Reliability Standard, substantiated by specific metrics described below, should a unit go offline per its established commitment. To assist in its determination, the EPA will seek FERC's advice regarding whether analysis of the reliability risk and the potential for violation of a mandatory Reliability Standard or increased loss of load expectation is adequately supported in the filed documentation.

This mechanism is for existing sources that have relied on a commitment to cease operating for purposes of these emission guidelines. Such reliance might occur in three circumstances: (1) units that plan to cease operation before January 1, 2032, and that are therefore exempt because they have elected to have enforceable cease operations dates in the state plan; (2) affected EGUs that choose to employ 40 percent natural gas co-firing by 2030 with a retirement date of no later than January 1, 2039; or (3) affected EGUs that have source-specific standards of performance based on remaining useful life, pursuant to the RULOF provisions outlined in section X.C.2 of this document. In each of these cases, units would have a commitment to cease operating by a date certain. This mechanism would allow for extensions of those dates to address unforeseen reliability or reserve margin concerns that arise due to changes in circumstances after the state plan has been finalized. Therefore, the date from which an extension can be given under this mechanism is the enforceable cease operations date in the state plan, including those prior to January 1, 2032. Only operators/owners of units that have satisfied all applicable milestones, metrics, and reporting obligations outlined in section X.C.3, and section X.C.4 for units with cease operation dates prior to January 1, 2032, would be eligible to use this mechanism.

This mechanism creates additional flexibility for specified narrow circumstances for existing sources and provides additional time and flexibility to allow a state, if necessary, to submit a plan revision should circumstances persist. In other words, this mechanism would be for use only when there is insufficient time to complete a state plan revision.

States can decide whether to include this extension mechanism in their state plans. If included in a state plan, the mechanism would be triggered when a unit submits an application to the EPA Regional Administrator where it faces an unforeseen situation that creates a

[1046] December 16, 2011, memorandum, "The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercery and Air Toxics Standard" from Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance.

[1047] See FERC Docket No. PL12–1–000.

[1048] *https://www.epa.gov/enforcement/enforcement-response-policy-mercury-and-air-toxics-standard-mats.*

[1049] *https://www.ferc.gov/sites/default/files/2020-04/E-5_9.pdf.*

reliability issue should that unit go offline consistent with its commitment to cease operations—for example, if the reliability coordinator identifies an unexpected capacity shortfall and determines that a specific unit(s) in a state(s) is needed to remain operational to satisfy a specific and documented reliability concern related to a unit's planned retirement. This mechanism would allow extensions, if approved by the Regional EPA Administrator, for units to operate after committed retirement dates without a full state plan revision. Any existing standard of performance finalized in the state plan under RULOF or the natural gas co-firing subcategory would remain in place. States have the discretion to place additional requirements on units requesting extensions. The relevant EPA Regional Administrator would approve the reliability assurance application or reject it if it were found that that the reliability assertion was not adequately supported. Units would need to substantiate the claim that they must remain online for reliability purposes with documentation demonstrating a forecasted reliability failure should the unit be taken offline, and this justification would need to be submitted to the appropriate EPA Regional Administrator and, for extensions exceeding 6 months, also to FERC, as described below. Extensions would be granted only for the duration of time demonstrated through the documentation, not to exceed 12 months, inclusive of the 6-month extension that is available and the relevant Planning Authority(ies) must certify that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested. Any further extension would require a state plan revision.

The process and documentation required to demonstrate that a unit is required to stay online because it is reliability-critical is described in this section.

In order to use this mechanism for an extension, certain conditions must be met by the unit and substantiated in written electronic notification to the appropriate EPA Regional Administrator, with an identical copy submitted to FERC for extension requests exceeding 6 months. More specifically, those conditions are that, where appropriate, the EGU owner complied with all applicable reporting obligations and milestones as described in sections X.C.4 (for units in the medium-term subcategory and units relying on a cease operation date for a less stringent standard of performance pursuant to RULOF), and section X.E.1.b.ii (for units with cease operation dates before January 1, 2032). No less than 30 days prior to the compliance date for applications for extensions of less than 6 months, and no less than 45 days prior to the compliance date for applications for extensions exceeding 6 months, but no earlier than 12 months prior to the compliance date (any requests over 12 months prior to a compliance date should be addressed through state plan revisions), a written complete application to activate the reliability assurance mechanism must be submitted to the appropriate EPA Regional Administrator, with a copy submitted to the state, including information responding to each of the seven elements listed as follows.

A copy of an extension request exceeding 6 months must also be submitted to FERC through a process and at an office of FERC's designation, including any additional specific information identified by FERC and responding to each of the following elements:

(1) Analysis of the reliability risk if the unit were not in operation demonstrating that the continued operation of the unit after the applicable compliance date is critical to maintaining electric reliability, such that retirement of that unit would trigger one or more of the following: (A) would result in noncompliance with at least one of the mandatory reliability standards approved by FERC, or (B) would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, this requires a clear demonstration that each unit would be needed to maintain the targeted level of resource adequacy.[1050] In addition, a projection substantiating the duration of the requested extension must be included for the length of time that the unit is expected to extend its cease-operations date because it is reliability-critical with accompanying analysis supporting the timeframe, not to exceed 12 months. The demonstration must satisfactorily substantiate at least one of the two conditions outlined above. Any unit that has received a Reliability Must Run Designation or equivalent from a reliability coordinator or balancing authority would fit this description. The types of information that will be helpful, based on the prior reliability extension process developed for MATS between the EPA and FERC include, but are not limited to, system planning and operations studies, system restoration studies or plans, operating procedures, and mitigation plans required by applicable Reliability Standards as defined by FERC in its May 17, 2012, Policy Statement issued to clarify requirements for the reliability extensions available through MATS.[1051]

(2) Analysis submitted by the relevant Planning Authority that verifies the reliability related claims, or presents a separate and equivalent analysis, confirming the asserted reliability risk if the unit were not in operation, or an explanation of why such a concurrence or separate analysis cannot be provided, and where necessary, any related system wide or regional analysis. This analysis or concurrence must include a substantiation for the duration of the extension request.

(3) Copies of any written comments from third parties regarding the extension.

(4) Demonstration from the unit owner/operator, grid operator and other relevant entities that they have a plan that includes appropriate actions, including bringing on new capacity or transmission, to resolve the underlying reliability issue, including the steps and timeframes for implementing measures to rectify the underlying reliability issue.

(5) Retirement date extensions allowed through this mechanism will be granted for only the increment of time that is substantiated by the reliability need and supporting documentation and may not exceed 12 months, inclusive of the 6-month extensions available with RTO, ISO, and reliability coordinator certification.

(6) For units affected by these emissions guidelines, states may choose to require the application to identify the level of operation that is required to avoid the documented reliability risk, and consistent with that level propose alternative compliance requirements, such as alternative standards or consistent utilization constraints for the duration of the extension. The EPA Regional Office may, within 30 days of the submission, reject the application if the submission is incomplete with respect to the above requirements or if the reliability assertion is not adequately supported.

(7) Only owners/operators of units that have satisfied all applicable milestone and reporting requirements and obligations under section X.C.3., and section X.C.4 for units with cease

[1050] Probabilistic Assessment: Technical Guideline Document, NERC, August 2016.

[1051] "Policy Statement on the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards" FERC, Issued May 17, 2012, at PL12–1–000.

operation dates prior to January 1, 2032, may use this mechanism for an extension as those sources will have provided information enabling the state and the public to assess that the units have diligently taken all actions necessary to meet their enforceable cease operations dates and demonstrate the use of all available tools to meet reliability challenges. Units that have failed to meet these obligations may make extension requests through the state plan revision process.

The EPA intends to consult with FERC in a timely manner on reliability-critical claims given FERC's expertise on reliability issues. The EPA may also seek advice from other reliability experts, to inform the EPA's decision. The EPA intends to decide whether it will grant a compliance extension for a retiring unit based on a documented reliability need within 30 days of receiving the application for applications less than 6 months, and within 45 days for applications exceeding 6 months to account for time needed to consult with FERC. Whether to grant an extension to an owner/operator is solely the decision of the EPA Regional Administrator.

For units already subject to standards of performance through state plans including those co-firing until 2039, and for units with specific, tailored and differentiated compliance dates developed through RULOF that employ this mechanism, those standards would apply during the extension.

4. Considerations for Evaluating 111 Final Actions With Other EPA Rules

Consistent with the EPA's statutory obligations under a range of CAA programs, the Agency has recently initiated and/or finalized multiple rulemakings to reduce emissions of air pollutants, air toxics, and greenhouse gases from the power sector. The EPA has conducted an assessment of the potential impacts of these regulatory efforts on grid resource adequacy, which is examined and discussed in the final TSD, *Resource Adequacy Analysis.* This analysis is informed by regional reserve margin targets, regional transmission capability, and generator availability. Moreover, as described in this action, the EPA designs its programs, implementation compliance flexibilities, and backstop mechanisms to be robust to future uncertainties and various compliance pathways for the collective of market and regulatory drivers. Finally, the backstop reliability mechanisms discussed in this section are, by design, similar to mechanisms utilized in the EPA's proposed Effluent Limitations Guidelines (ELG) rulemaking. There, to ensure that units choosing to permanently cease the combustion of coal by a particular date in their permits are not restricted from operation in the event of an emergency related to load balancing, the permit conditions allow for grid emergency exemptions (88 FR 18900). Harmonizing the use of similar criteria for emergency related reliability concerns across the two rules further buttresses unit confidence that grid reliability and environmental responsibilities will not come into conflict. It also streamlines the demonstrations and evidence that a unit must provide in such events. This cross-regulatory harmonization ensures that the Agency can successfully meet its CWA and CAA responsibilities regarding public health in a manner consistent with grid stability as it has consistently done throughout its 54-year history.

The EPA has taken into consideration, to the extent possible, the alignment of compliance timeframes and other aspects of these policies for affected units. For each regulatory effort, there has been coordination and alignment of requirements and timelines, to the extent possible. The potential impact of these various regulatory efforts is further examined in the final TSD, *Resource Adequacy Analysis.* Additionally, the EPA considered the impact of this suite of power sector rules by performing a variety of sensitivity analyses described in XII.F.3. These considerations are discussed in the technical memoranda, *IPM Sensitivity* Runs and *Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG, and MATS,* available in the rulemaking docket.

XIII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, EPA, submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Any changes made in response to recommendations received as part of Executive Order 12866 review have been documented in the docket.

The EPA prepared an analysis of the potential costs and benefits associated with these actions. This analysis, ''Regulatory Impact Analysis for the 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,'' is available in the docket and describes in detail the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates.

Table 6 presents the estimated present values (PV) and equivalent annualized values (EAV) of the projected climate benefits, health benefits, compliance costs, and net benefits of the final rules in 2019 dollars discounted to 2024. This analysis covers the impacts of the final standards for new combustion turbines and for existing steam generating EGUs. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the final rules.

Under E.O. 12866, the EPA is directed to consider the costs and benefits of its actions. Accordingly, in addition to the projected climate benefits of the final rules from anticipated reductions in CO_2 emissions, the projected monetized health benefits include those related to public health associated with projected reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3 and 7 percent. As shown in section 4.3.9 of the RIA, there are health benefits in the years 2028, 2030, 2035, and 2045 and health disbenefits in 2040. The projected climate benefits in this table are based on estimates of the social cost of carbon ($SC\text{–}CO_2$) at a 2 percent near-term Ramsey discount rate and are discounted using a 2 percent discount rate to obtain the PV and EAV estimates in the table. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and illustrative policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the final requirements.

These results present an incomplete overview of the potential effects of the final rules because important categories of benefits—including benefits from reducing HAP emissions—were not monetized and are therefore not reflected in the benefit-cost tables. The EPA anticipates that taking non-monetized effects into account would show the final rules to have a greater net benefit than this table reflects.

TABLE 6—PROJECTED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULES, 2024 THROUGH 2047

[Billions 2019$, discounted to 2024] [a]

	Present value (PV)		
	2% Discount rate	3% Discount rate	7% Discount rate
Climate Benefits [c]	270	270	270
Health Benefits [d]	120	100	59
Compliance Costs	19	15	7.5
Net Benefits [e]	370	360	320
Equivalent Annualized Value (EAV) [b]			
Climate Benefits [c]	14	14	14
Health Benefits [d]	6.3	6.1	5.2
Compliance Costs	0.98	0.91	0.65
Net Benefits [e]	20	19	19
Non-Monetized Benefits [e]	Benefits from reductions in HAP emissions Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP Reductions in exposure to ambient NO_2 and SO_2 Improved visibility (reduced haze) from $PM_{2.5}$ reductions		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The annualized present value of costs and benefits are calculated over the 24-year period from 2024 to 2047.

[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC–CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC–CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[d] The projected monetized air quality related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent. This table presents the net health benefit impact over the analytic timeframe of 2024 to 2047. As shown in section 4.3.9 of the RIA, there are health benefits in the years 2028, 2030, 2035, and 2045 and health disbenefits in 2040.

[e] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See section 4.2 of the RIA for a discussion of climate effects that are not yet reflected in the SC–CO_2 and thus remain unmonetized and section 4.4 of the RIA for a discussion of other non-monetized benefits.

As shown in table 6, the final rules are projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent. The final rules are also projected to reduce emissions of NO_X, SO_2 and direct $PM_{2.5}$ leading to national health benefits from $PM_{2.5}$ and ozone in most years, producing a projected PV of monetized health benefits of about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Thus, these final rules are expected to generate a PV of monetized benefits of $390 billion, with an EAV of $21 billion discounted at a 2 percent rate. The PV of the projected compliance costs are $19 billion, with an EAV of about $0.98 billion discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $370 billion and EAV of about $20 billion.

At a 3 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at 3 percent. The PV of the projected compliance costs are about $15 billion, with an EAV of $0.91 billion discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $360 billion and an EAV of about $19 billion.

At a 7 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at 7 percent. The PV of the projected compliance costs are about $7.5 billion, with an EAV of $0.65 billion discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $320 billion and an EAV of about $19 billion.

We also note that the RIA follows the EPA's historic practice of using a detailed technology-rich partial equilibrium model of the electricity and related fuel sectors to estimate the incremental costs of producing electricity under the requirements of proposed and final major EPA power sector rules. In section 5.2 of the RIA for these actions, the EPA has also included an economy-wide analysis that considers additional facets of the economic response to the final rules, including the full resource requirements of the expected compliance pathways, some of which are paid for through subsidies. The social cost estimates in the economy-wide analysis and discussed in section 5.2 of the RIA are still far below the projected benefits of the final rules.

B. Paperwork Reduction Act (PRA)

1. 40 CFR Part 60, Subpart TTTT

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0685.

2. 40 CFR Part 60, Subpart TTTTa

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2771.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

Respondents/affected entities: Owners and operators of fossil-fuel fired EGUs.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 2.

Frequency of response: Annual.

Total estimated burden: 110 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $12,000 (per year), includes $0 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

3. 40 CFR Part 60, Subpart UUUUa

This action does not impose an information collection burden under the PRA.

4. 40 CFR Part 60, Subpart UUUUb

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2770.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This rule imposes specific requirements on state governments with existing fossil fuel-fired steam generating units. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit GHG emissions from these existing EGUs. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation) is estimated to be 89,000 hours at a total annual labor cost of $11.7 million. The annual burden for the Federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 24,000 hours at a total annual labor cost of $1.7 million. Burden is defined at 5 CFR 1320.3(b).

Respondents/affected entities: States with one or more designated facilities covered under subpart UUUUb.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 43.

Frequency of response: Once.

Total estimated burden: 89,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $11.7 million, includes $35,000 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

Pursuant to sections 603 and 609(b) of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. Summaries of the IRFA and Panel recommendations are presented in the supplemental proposed rule at 88 FR 80582 (November 20, 2023). The complete IRFA and Panel Report are available in the docket for this action.[1052]

As required by section 604 of the RFA, the EPA prepared a final regulatory flexibility analysis (FRFA) for this action. The FRFA provides a statement of the need for, and objectives of, the rule; addresses the issues raised by public comments on the IRFA for the proposed rule, including public comments filed by the Chief Counsel for Advocacy of the Small Business Administration; describes the small entities to which the rule will apply; describes the projected reporting, recordkeeping and other compliance requirements of the rule and their impacts; and describes the steps the agency has taken to minimize impacts on small entities consistent with the stated objectives of the Clean Air Act. The complete FRFA is available for review in the docket and is summarized here. The scope of the FRFA is limited to the NSPS. The impacts of the emission guidelines are not evaluated here because the emission guidelines do not place explicit requirements on the regulated industry. Those impacts will be evaluated pursuant to the development of a Federal plan.

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare. Since that time, the evidence of the harms posed by GHG emissions has only grown and Americans experience the destructive and worsening effects of climate change every day. Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2021. At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources are available to the power sector, and multiple projects are in various stages of operation and development. Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is finalizing several actions under CAA section 111 to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing emission guidelines and NSPS that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of CAA section 111, the final NSPS and emission guidelines reflect the application of the BSER that,

[1052] See Document ID No. EPA–HQ–OAR–2023–0072–8109 and Document ID No. EPA–HQ–OAR–2023–0072–8108.

taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

These final actions ensure that EGUs reduce their GHG emissions in a manner that is cost-effective and improve the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These standards and emission guidelines will significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA has designed these standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

The significant issues raised in public comments specifically in response to the initial regulatory flexibility analysis came from the Office of Advocacy within the Small Business Administration (Advocacy). The EPA agreed that convening a SBAR Panel was warranted because the EPA solicited comment on a number of policy options that, if finalized, could affect the estimate of total compliance costs and therefore the impacts on small entities. The EPA issued an IRFA and solicited comment on regulatory flexibilities for small business in a supplemental proposed rule, published in November 2023.

Advocacy provided further substantive comments on the IRFA that accompanied the November 2023 supplemental proposed rule. The comments reiterated the concerns raised in its original comment letter on the proposed rule and further made the following claims: (1) the IRFA does not provide small entities an accurate description of the impacts of the proposed rule, (2) small entities remain concerned that the EPA has not taken reliability concerns seriously.

In response to these comments and feedback during the SBAR Panel, the EPA revised its small business assessment to incorporate the final SBA guidelines (effective March 17th 2023) when performing the screening analysis to identify small businesses that have built or have planned/committed builds of combustion turbines since 2017. The EPA also treated additional entities within this subset as small based on feedback received during the panel process. The net effect of these changes is to increase the total compliance cost attributed to small entities, and the number of small entities potentially affected. The EPA additionally increased the assumed delivered hydrogen price to $1.15/kg.

Further, the EPA is finalizing multiple adjustments to the proposed rule that ensure the requirements in the final actions can be implemented without compromising the ability of power companies, grid operators, and state and Federal energy regulators to maintain resource adequacy and grid reliability.

To estimate the number of small businesses potentially impacted by the NSPS, the EPA performed a small entity screening analysis for impacts on all affected EGUs by comparing compliance costs to historic revenues at the ultimate parent company level. The EPA reviewed historical data and planned builds since 2017 to determine the universe of NGCC and natural gas combustion turbine additions. Next, the EPA followed SBA size standards to determine which ultimate parent entities should be considered small entities in this analysis.

Once the costs of the rule were calculated, the costs attributed to small entities were calculated by multiplying the total costs to the share of the historical build attributed to small entities. These costs were then shared to individual entities using the ratio of their build to total small entity additions in the historical dataset.

The EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Of the 14 entities that own NGCC units considered in this analysis, three are projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035 and none are projected to experience compliance costs greater than or equal to 3 percent of generation revenues in 2035.

Prior to the November 2023 supplemental proposed rule, the EPA convened a SBAR Panel to obtain recommendations from small entity representatives (SERs) on elements of the regulation. The Panel identified significant alternatives for consideration by the Administrator of the EPA, which were summarized in a final report. Based on the Panel recommendations, as well as comments received in response to both the May 2023 proposed rule and the November 2023 supplemental proposed rule, the EPA is finalizing several regulatory alternatives that could accomplish the stated objectives of the Clean Air Act while minimizing any significant economic impact of the final rule on small entities. Discussion of those alternatives is provided below.

Mechanisms for reliability relief: As described in section XII.F of this preamble, the EPA is finalizing several adjustments to provisions in the proposed rules that address reliability concerns and ensure that the final rules provide adequate flexibilities and assurance mechanisms that allow grid operators to continue to fulfill their responsibilities to maintain the reliability of the bulk-power system. The EPA is additionally finalizing additional reliability-related instruments to provide further certainty that implementation of these final rules will not intrude on grid operator's ability to ensure reliability. The short-term reliability emergency mechanism, which is available for both new and existing units, is designed to provide an alternative compliance strategy during acute system emergencies when reliability might be threatened. The reliability assurance mechanism will be available for existing units that intend to cease operating, but, for unforeseen reasons, need to temporarily remain online to support reliability beyond the planned cease operation date. This reliability assurance mechanism, which requires an adequate showing of reliability need, is intended to apply to circumstances where there is insufficient time to complete a state plan revision. Whether to grant an extension to an owner/operator is solely the decision of the EPA. Concurrence or approval of FERC is not a condition but may inform EPA's decision. These instruments will be presumptively approvable, provided they meet the requirements defined in these emission guidelines, if states choose to incorporate them into their plans.

Throughout the SBAR Panel outreach, SERs expressed concerns that the proposed rule will have significant reliability impacts, including that areas with transmission system limitations and energy market constraints risk power interruption if replacement generation cannot be put in place before retirements. SERs recommended that Regional Transmission Organizations (RTOs) be involved to evaluate safety and reliability concerns.

SERs additionally stated that the proposed rule relies on the continued development of technologies not currently in wide use and large-scale investments in new infrastructure and that the proposed rule pushes these technologies significantly faster than the infrastructure will be ready and sooner than the SERs can justify investment to their stakeholders and ratepayers. SERs stated that this is of particular concern for small entities that are retiring generation in response to other regulatory mandates and need to replace that generation to continue serving their customers.

The suite of comprehensive adjustments in the final rules, along with the two explicit reliability mechanisms are directly responsive to SER's statements and concerns about grid reliability and the impact of retiring generating on small businesses.

Subcategories: Throughout the SBAR Panel, SERs expressed concerns that control requirements on rural electric cooperatives may be an additional hardship on economically disadvantaged communities and small entities. SERs stated that the EPA should further evaluate increased energy costs, transmission upgrade costs, and infrastructure encroachment which are concrete effects on the disproportionately impacted communities. Additionally, SERs stated hydrogen and CCS cannot be BSER because they are not commercially available and viable in very rural areas.

The EPA solicited comment on potential exclusions or subcategories for small entities that would be based on the class, type, or size of the source and be consistent with the Clean Air Act. The EPA also solicited comment on whether rural electric cooperatives and small utility distribution systems (serving 50,000 customers or less) can expect to have access to hydrogen and CCS infrastructure, and if a subcategory for these units is appropriate.

The EPA evaluated public comments received and determined that establishing a separate subcategory for rural electric cooperatives was not warranted. However, the EPA is not finalizing the low-GHG hydrogen BSER pathway. In response to concerns raised by small business and other commenters, the EPA conducted additional analysis of the BSER criteria and its proposed determination that low-GHG hydrogen co-firing qualified as the BSER. This additional analysis led the EPA to assess that the cost of low-GHG hydrogen in 2030 will likely be higher than proposed, and these higher cost estimates and associated uncertainties related to its nationwide availability were key factors in the EPA's decision to revise its 2030 cost estimate for delivered low-GHG hydrogen and are reflected in the increased price. For CCS, as discussed in sections VIII.F.4.c.iv and VII.C.1.a of this preamble, the EPA considered geographic availability of sequestration, as well as the timelines, materials, and workforce necessary for installing CCS, and determined they are sufficient. Moreover, while the BSER is premised on source-to-sink CO_2 pipelines and sequestration, the EPA notes that many EGUs in rural areas are primed to take advantage of synergy with the broader deployment of CCS in other industries. Capture, pipelines, and sequestration are already in place or in advanced stages of deployment for ethanol production from corn, an industry rooted in rural areas. The high purity CO_2 from ethanol production provides advantageous economics for CCS.

The EPA believes the decision to not finalize a low-GHG hydrogen BSER pathway is responsive to SER's statements and concerns regarding the availability of low-GHG hydrogen in very rural areas.

In addition, the EPA is preparing a Small Entity Compliance Guide to help small entities comply with this rule. The guide will be available 60 days after publication of the final rule at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

D. Unfunded Mandates Reform Act of 1995 (UMRA)

The NSPS contain a Federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for the private sector in any one year. The NSPS do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538 for state, local, and tribal governments, in the aggregate. Accordingly, the EPA prepared, under section 202 of UMRA, a written statement of the benefit-cost analysis, which is in section XIII.A of this preamble and in the RIA.

The repeal of the ACE Rule and emission guidelines do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and do not significantly or uniquely affect small governments. The emission guidelines do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop plans to implement the guidelines under CAA section 111(d) for designated EGUs. The burden for states to develop CAA section 111(d) plans in the 24-month period following promulgation of the emission guidelines was estimated and is listed in section XIII.B, but this burden is estimated to be below $100 million in any one year. As explained in section X.E.6, the emission guidelines do not impose specific requirements on tribal governments that have designated EGUs located in their area of Indian country.

These actions are not subject to the requirements of section 203 of UMRA because they contain no regulatory requirements that might significantly or uniquely affect small governments. In light of the interest in these actions among governmental entities, the EPA initiated consultation with governmental entities. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, including the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and National Association of Regulatory Utility Commissioners to participate in the meeting. The purpose of the consultation was to provide general background on these rulemakings, answer questions, and solicit input from state and local governments. For a summary of the UMRA consultation see the memorandum in the docket titled *Federalism Pre-Proposal Consultation Summary.*[1053]

E. Executive Order 13132: Federalism

These actions do not have federalism implications as that term is defined in E.O. 13132. Consistent with the cooperative federalism approach directed by the Clean Air Act, states will establish standards of performance for existing sources under the emission guidelines set out in this final rule. These actions will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

Although the direct compliance costs may not be substantial, the EPA nonetheless elected to consult with representatives of state and local governments in the process of

[1053] See Document ID No. EPA–HQ–OAR–2023–0072–0033.

developing these actions to permit them to have meaningful and timely input into their development. The EPA's consultation regarded planned actions for the NSPS and emission guidelines. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, including the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and National Association of Regulatory Utility Commissioners to participate in the meeting. The purpose of the consultation was to provide general background on these rulemakings, answer questions, and solicit input from state and local governments. For a summary of the Federalism consultation see the memorandum in the docket titled *Federalism Pre-Proposal Consultation Summary.*[1054]

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

These actions do not have tribal implications, as specified in Executive Order 13175. The NSPS imposes requirements on owners and operators of new or reconstructed stationary combustion turbines and the emission guidelines do not impose direct requirements on tribal governments. Tribes are not required to develop plans to implement the emission guidelines developed under CAA section 111(d) for designated EGUs. The EPA is aware of two fossil fuel-fired steam generating units located in Indian country, and one fossil fuel-fired steam generating units owned or operated by tribal entities. The EPA notes that the emission guidelines do not directly impose specific requirements on EGU sources, including those located in Indian country, but before developing any standards for sources on tribal land, the EPA would consult with leaders from affected tribes. Thus, Executive Order 13175 does not apply to these actions.

Because the EPA is aware of tribal interest in these rules and consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered government-to-government consultation with tribes and conducted outreach and engagement.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks Populations and Low-Income Populations

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is a significant regulatory action as defined by E.O. 12866(3)(f)(1), and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the Agency has evaluated the environmental health and welfare effects of climate change on children. GHGs contribute to climate change and are emitted in significant quantities by the power sector. The EPA believes that the GHG emission reductions resulting from implementation of these standards and guidelines will further improve children's health. The assessment literature cited in the EPA's 2009 Endangerment Findings concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects (74 FR 66524, December 15, 2009). The assessment literature since 2016 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience. These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More detailed information on the impacts of climate change to human health and welfare is provided in section III of this preamble. Under these final actions, the EPA expects that CO_2 emissions reductions will improve air quality and mitigate climate impacts which will benefit the health and welfare of children.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

These actions, which are significant regulatory actions under Executive Order 12866, are likely to have to have a significant adverse effect on the supply, distribution or use of energy. The EPA has prepared a Statement of Energy Effects for these actions as follows. The EPA estimates a 1.4 percent increase in retail electricity prices on average, across the contiguous U.S. in 2035, and a 42 percent reduction in coal-fired electricity generation in 2035 as a result of these actions. The EPA projects that utility power sector delivered natural gas prices will increase 3 percent in 2035. As outlined in the Final TSD, *Resource Adequacy Analysis,* available in the docket for this rulemaking, the EPA demonstrates that compliance with the final rules can be achieved while maintaining resource adequacy, and that the rules include additional flexibility measures designed to address reliability-related concerns. For more information on the estimated energy effects, please refer section 3 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This rulemaking involves technical standards. Therefore, the EPA conducted searches for the 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 through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Method 19 of 40 CFR part 60, appendix A. No applicable voluntary consensus standards (VCS) were identified for EPA Method 19. For additional information, please see the March 23, 2023, memorandum titled *Voluntary Consensus Standard Results for New Source Performance Standards for*

[1054] See Document ID No. EPA–HQ–OAR–2023–0072–0033.

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.[1055]

In accordance with the requirements of 1 CFR part 51, the EPA is incorporating the following 10 voluntary consensus standards by reference in the final rule.

• ANSI C12.20–2010, American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010) is cited in the final rule to assure consistent monitoring of electric output. This standard establishes the physical aspects and acceptable performance criteria for 0.2 and 0.5 accuracy class electricity meters. These meters would be used to measure hourly electric output that would be used, in part, to calculate compliance with an emissions standard.

• ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), is cited in the final rule to provide directions and rules for conduct and reporting of results of thermal performance tests for open cycle simple cycle combustion turbines. The object is to determine the thermal performance of the combustion turbine when operating at test conditions and correcting these test results to specified reference conditions. PTC 22 provides explicit procedures for the determination of the following performance results: corrected power, corrected heat rate (efficiency), corrected exhaust flow, corrected exhaust energy, and corrected exhaust temperature. Tests may be designed to satisfy different goals, including absolute performance and comparative performance.

• ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), is cited in the final rule to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of heat-cycle electric power plants and combined heat and power units (PTC 46 is not applicable to simple cycle combustion turbines). Test results provide a measure of the performance of a power plant or thermal island at a specified cycle configuration, operating disposition and/or fixed power level, and at a unique set of base reference conditions. PTC 46 provides explicit procedures for the determination of the following performance results: corrected net power, corrected heat rate, and corrected heat input.

• ASTM D388–99 (Reapproved 2004), Standard Classification of Coals by Rank, covers the classification of coals by rank, that is, according to their degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite. It is used to define coal as a fuel type which is then referenced when defining coal-fired electric generating units, one of the subjects of this rule.

• ASTM D396–98, Standard Specification for Fuel Oils, covers grades of fuel oil intended for use in various types of fuel-oil-burning equipment under various climatic and operating conditions. These include Grades 1 and 2 (for use in domestic and small industrial burners), Grade 4 (heavy distillate fuels or distillate/residual fuel blends used in commercial/industrial burners equipped for this viscosity range), and Grades 5 and 6 (residual fuels of increasing viscosity and boiling range, used in industrial burners).

• ASTM D975–08a, Standard Specification for Diesel Fuel Oils, covers seven grades of diesel fuel oils based on grade, sulfur content, and volatility. These grades range from Grade No. 1–D S15 (a special-purpose, light middle distillate fuel for use in diesel engine applications requiring a fuel with 15 ppm sulfur (maximum) and higher volatility than that provided by Grade No. 2–D S15 fuel) to Grade No. 4–D (a heavy distillate fuel, or a blend of distillate and residual oil, for use in low- and medium-speed diesel engines in applications involving predominantly constant speed and load).

• ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008) covers two grades of kerosene suitable for use in critical kerosene burner applications: No. 1–K (a special low sulfur grade kerosene suitable for use in non-flue-connected kerosene burner appliances and for use in wick-fed illuminating lamps) and No. 2–K (a regular grade kerosene suitable for use in flue-connected burner appliances and for use in wick-fed illuminating lamps). It is used to define kerosene, which is a type of uniform fuel listed in this rule.

• ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011) covers biodiesel (B100) Grades S15 and S500 for use as a blend component with middle distillate fuels. It is used to define biodiesel, which is a type of uniform fuel listed in this rule.

• ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010) covers fuel blend grades of 6 to 20 volume percent biodiesel with the remainder being a light middle or middle distillate diesel fuel, collectively designated as B6 to B20. It is used to define biodiesel blends, which is a type of uniform fuel listed in this rule.

• ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009) is cited in the final rule for its guidance on determining performance characteristics of stationary combustion turbines. ISO 2314 specifies guidelines and procedures for preparing, conducting and reporting thermal acceptance tests in order to determine and/or verify electrical power output, mechanical power, thermal efficiency (heat rate), turbine exhaust gas energy and/or other performance characteristics of open-cycle simple cycle combustion turbines using combustion systems supplied with gaseous and/or liquid fuels as well as closed-cycle and semi closed-cycle simple cycle combustion turbines. It can also be applied to simple cycle combustion turbines in combined cycle power plants or in connection with other heat recovery systems. ISO 2314 includes procedures for the determination of the following performance parameters, corrected to the reference operating parameters: electrical or mechanical power output (gas power, if only gas is supplied), thermal efficiency or heat rate; and combustion turbine engine exhaust energy (optionally exhaust temperature and flow).

The EPA determined that the ANSI, ASME, ASTM, and ISO standards, notwithstanding the age of the standards, are reasonably available because they are available for purchase from the following addresses: American National Standards Institute (ANSI), 25 West 43rd Street, 4th Floor, New York, NY 10036–7422, +1.212.642.4900, *info@ansi.org*, *www.ansi.org*; American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990, +1.800.843.2763, *customercare@asme.org*, *www.asme.org*; ASTM International, 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, +1.610.832.9500, *www.astm.org*; International Organization for Standardization (ISO), Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland, +41.22.749.01.11, *customerservice@iso.org*, *www.iso.org*.

[1055] See Document ID No. EPA–HQ–OAR–2023–0072–0032.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to these actions result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. Baseline $PM_{2.5}$ and ozone and exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, and those without a high school diploma may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian populations, residents of Tribal Lands, populations with life expectancy data unavailable, children, and unemployed populations may also experience disproportionately higher ozone concentrations than the national average. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the national average.

For existing sources, the EPA believes that this action is not likely to change existing disproportionate and adverse disparities among communities with EJ concerns regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures for most demographic groups in the future years evaluated. However, in 2035, under the illustrative compliance scenarios analyzed, it is possible that Asian populations, Hispanic populations, and those linguistically isolated, and those living on Tribal land may experience a slight exacerbation of ozone exposure disparities at the national level (EJ question 3). Additionally at the national level, those living on Tribal land may experience a slight exacerbation of ozone exposure disparities in 2040 and a slight mitigation of ozone exposure disparities in 2028 and 2030. At the state level, ozone exposure disparities may be either mitigated or exacerbated for certain demographic groups analyzed, also to a small degree. As discussed above, it is important to note that this analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

For new sources, the EPA believes that it is not practicable to assess whether this action is likely to result in new disproportionate and adverse effects on communities with environmental justice concerns, because the location and number of new sources is unknown. However, the EPA believes that the projected total cumulative power sector reduction of 1,365 million metric tons of CO_2 emissions between 2028 and 2047 will have a beneficial effect on populations at risk of climate change effects/impacts. Research indicates that racial, ethnic, and low socioeconomic status, vulnerable lifestages, and geographic locations may leave individuals uniquely vulnerable to climate change health impacts in the U.S.

The information supporting this Executive Order review is contained in section XII.E of this preamble and in section 6, Environmental Justice Impacts of the RIA, which is in the public docket.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit the rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

XIV. Statutory Authority

The statutory authority for the actions in this rulemaking is provided by sections 111, 302, and 307(d)(1) of the CAA as amended (42 U.S.C. 7411, 7602, 7607(d)(1)). These actions are subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons set forth in the preamble, the EPA amends 40 CFR part 60 as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Section 60.17 is amended by:
■ a. Revising paragraphs (d)(1), (g)(15) and (16), (h)(38), (43), (47), (145), (206), and (212), the introductory text of paragraph (i);
■ b. Removing note 1 to paragraph (k) and paragraph (l);
■ c. Redesignating paragraphs (j) through (u) as shown in the following table:

Old paragraph	New paragraph
(j)	(k).
(k)	(m).
(m) through (o)	(n) through (p).
(p) through (r)	(r) through (t).
(s)	(q).
(t)	(j).
(u)	(l).

■ d. Revising newly-redesignated paragraphs (j) and (l), the introductory text to newly-redesignated paragraph (m), newly-redesignated paragraph (n), and the introductory text to newly-redesignated paragraphs (o), (q), and (r).

The revisions read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(d) * * *

(1) ANSI No. C12.20–2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010); IBR approved for §§ 60.5535(d); 60.5535a(d); 60.5860b(a).

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(g) * * *

(15) ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014); IBR approved for §§ 60.5580; 60.5580a.

(16) ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15,1997); IBR approved for §§ 60.5580; 60.5580a.

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(h) * * *

(38) ASTM D388–99 (Reapproved 2004) ε^1(ASTM D388–99R04), Standard Classification of Coals by Rank, (Approved June 1, 2004); IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251; 60.5580; 60.5580a.

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(43) ASTM D396–98, Standard Specification for Fuel Oils, (Approved April 10, 1998); IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b); 60.5580; 60.5580a.

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(47) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, (Approved October 1, 2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.

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(145) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1,

2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.

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(206) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, 60.5580, and 60.5580a.

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(212) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, 60.5580, and 60.5580a.

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(i) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209; phone: (301) 927–7077; website: *https://www.aoac.org/*.

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(j) CSA Group (CSA) (formerly Canadian Standards Association), 178 Rexdale Boulevard, Toronto, Ontario, Canada; phone: (800) 463–6727; website: *https://shop.csa.ca*.

(1) CSA B415.1–10, Performance Testing of Solid-fuel-burning Heating Appliances, (March 2010), IBR approved for §§ 60.534; 60.5476.

(2) [Reserved]

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(l) European Standards (EN), European Committee for Standardization, Management Centre, Avenue Marnix 17, B–1000 Brussels, Belgium; phone: + 32 2 550 08 11; website: *https://www.en-standard.eu*.

(1) DIN EN 303–5:2012E (EN 303–5), Heating boilers—Part 5: Heating boilers for solid fuels, manually and automatically stoked, nominal heat output of up to 500 kW—Terminology, requirements, testing and marking, (October 2012), IBR approved for § 60.5476.

(2) [Reserved]

* * * * *

(m) GPA Midstream Association, 6060 American Plaza, Suite 700, Tulsa, OK 74135; phone: (918) 493–3872; website: *www.gpamidstream.org*.

* * * * *

(n) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland; phone: + 41 22 749 01 11; website: *www.iso.org*.

(1) ISO 8178–4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—part 4: Test Cycles for Different Engine Applications, IBR approved for § 60.4241(b).

(2) ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009), IBR approved for §§ 60.5580; 60.5580a.

(3) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition, IBR approved for § 60.107a(d).

(4) ISO 10715:1997(E), Natural gas—Sampling guidelines, (First Edition, June 1, 1997), IBR approved for § 60.4415(a).

(o) National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161.

* * * * *

(q) Pacific Lumber Inspection Bureau (formerly West Coast Lumber Inspection Bureau), 1010 South 336th Street #210, Federal Way, WA 98003; phone: (253) 835.3344; website: *www.plib.org*.

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(r) Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092; phone (800) 332–8686; website: *www.tappi.org*.

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Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

■ 3. Section 60.5508 is revised to read as follows:

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit or an integrated gasification combined cycle (IGCC) facility that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, or commences modification after January 8, 2014, but on or before May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction after January 8, 2014, but on or before May 23, 2023, or commences reconstruction after June 18, 2014, but on or before May 23, 2023. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

■ 4. Section 60.5509 is revised to read as follows:

§ 60.5509 What are my general requirements for complying with this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commenced construction after January 8, 2014, but on or before May 23, 2023, or commenced reconstruction after June 18, 2014, but on or before May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (10) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating

of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this paragraph (b)(7) continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.*, not connected to a natural gas pipeline).

(9) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

(10) Your EGU is subject to subpart TTTTa of this part.

■ 5. Section 60.5520 is revised to read as follows:

§ 60.5520 What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 or 2 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 2 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 2 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.*, uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.*, non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

■ 6. Section 60.5525 is revised to read as follows:

§ 60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 or 2 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under § 60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard = \frac{(50 \text{ x } HTIP_{ng}) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.*, no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 or 2 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced commercial operation (as defined in 40 CFR 72.2) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under 40 CFR 75.64(a) has passed prior to October 23, 2015, emissions reporting shall begin according to § 60.5555(c)(3)(i) (for Acid Rain program units), or according to § 60.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under 40 CFR 75.64(a) occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 60.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 60.5555(c)(3)(iii).

(4) Electric sales by your affected facility generated when it operated during a system emergency as defined in § 60.5580 are excluded for applicability with the base load standard if you can sufficiently provide the documentation listed in § 60.5560(i).

■ 7. Section 60.5535 is amended by revising paragraphs (a), (b), (c)(3), (d)(1), (e), and (f) to read as follows:

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.*, carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for "valid operating hours", as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from equation F–11 in appendix F to 40

CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) * * *

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

* * * * *

(d) * * *

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.*, lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.*, hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

* * * * *

(e) Consistent with § 60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 or 2 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternative, or if the EGUs are subject to different emission standards in table 1 or 2 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

* * * * *

■ 8. Section 60.5540 is revised to read as follows:

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 or 2 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.*, either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535(b) or (c), as applicable, and either the generating load data from § 60.5535(d)(1) for output-based calculations or the heat input data from § 60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.*, blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.*, operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of 40 CFR 75 are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535 for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520) value reported under 40 CFR part 75 to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.*, denominator) of their actual 12-operating month emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual 12-operating month emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section.

Round off the result to two significant figures.

(b) In accordance with § 60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 or 2 to this subpart, or the emissions standard calculated in accordance with § 60.5525(a)(2).

■ 9. Section 60.5555 is amended by revising paragraphs (a)(2)(iv) and (v), (f), and (g) to read as follows.

§ 60.5555 What reports must I submit and when?

(a) * * *

(2) * * *

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.*, the total number of valid operating hours (as defined in § 60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

* * * * *

(f) If your affected EGU captures CO_2 to meet the applicable emissions standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

■ 10. Section 60.5560 is amended by adding paragraphs (h) and (i) to read as follows:

§ 60.5560 What records must I maintain?

* * * * *

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert, and documentation of the exact duration of the event;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located, and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

■ 11. Section 60.5580 is amended by:

■ a. Revising the definitions for "Annual capacity factor", and "Base load rating";

■ b. Revising and republishing the definition for "Coal"; and

■ c. Revising the definitions for "Combined cycle unit", "Combined head and power unit or CHP unit", "Design efficiency", "Distillate oil", "ISO conditions", "Net electric sales", and "System emergency".

The revisions and republications read as follows:

§ 60.5580 What definitions apply to this subpart?

* * * * *

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.*, solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.*, solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388–99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit*, (also known as "cogeneration") means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.*, electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.*, CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22–2014, ASME PTC 46–1996, ISO 2314:2009(E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699–08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751–11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467–10 (incorporated by reference, see § 60.17).

* * * * *

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

* * * * *

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

* * * * *

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor.

* * * * *

■ 12. Table 1 to subpart TTTT is revised to read as follows:

Table 1 to Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Steam Generating Units and Integrated Gasification Combined Cycle Facilities That Commenced Construction After January 8, 2014, and Reconstruction or Modification After June 18, 2014

[*Note:* Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh-gross).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg CO_2/MWh of gross energy output (2,000 lb CO_2/MWh-gross).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg CO_2/MWh of gross energy output (1,800 lb CO_2/MWh-gross).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: (1) 820 kg CO_2/MWh of gross energy output (1,800 lb CO_2/MWh-gross) for units with a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h); or (2) 910 kg CO_2/MWh of gross energy output (2,000 lb CO_2/MWh-gross) for units with a base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.

■ 13. Table 2 to subpart TTTT is revised to read as follows:

Table 2 to Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction After January 8, 2014, and Reconstruction After June 18, 2014 (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[*Note:* Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	450 kg CO_2/MWh (1,000 lb CO_2/MWh) of gross energy output; or 470 kg CO_2/MWh (1,030 lb CO_2/MWh) of net energy output.

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis].	50 kg CO_2/GJ (120 lb CO_2/MMBtu) of heat input.
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis.	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525.

■ 14. Table 3 to subpart TTTT is revised to read as follows:

Table 3 to Subpart TTTT of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§ 60.8(c)–(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§ 60.14	Modification	Yes (steam generating units and IGCC facilities). No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

■ 15. Add subpart TTTTa to read as follows:

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Applicability

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.*, uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.*, non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard\ = \frac{(50 \text{ x } HTIP_{ng}) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2\ emissions\ standard\ = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.*, no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.*, carbon capture and storage), you may use data from a certified oxygen

(O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ''valid operating hours'', as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F–11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G–4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F–7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G–4 nomenclature.

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G–4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.*, lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.*, hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.*, lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C–1 of 40 CFR part 98. If your fuel is not listed in table C–1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A–7 to this part, and you must convert your CO_2 emissions to heat input using Equation G–4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.*, either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.*, blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.*, operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_{A}}{TDF} + [\, (Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE} \,] \text{ (Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \text{ (Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.*, denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.*, CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.*, the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit

reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.*, beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the Administrator has delegated authority to your state, local, or Tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions) of this part.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388–99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit,* (also known as "cogeneration") means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22–2014, ASME PTC 46–1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699–08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751–11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467–10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/

h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.*, a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.*, onsite photovoltaics), integrated energy storage (*e.g.*, onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.*, steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.*, economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

TABLE 1 TO SUBPART TTTTA OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 23, 2023 (GROSS OR NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

TABLE 2 TO SUBPART TTTTA OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STEAM GENERATING UNITS OR IGCC THAT COMMENCED MODIFICATION AFTER MAY 23, 2023

Affected EGU	CO_2 Emission standard
Modified coal-fired steam generating unit.	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

TABLE 3 TO SUBPART TTTTA OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTTA

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping.	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No..	
§ 60.8(b)	Performance test method alternatives.	Yes	Administrator can approve alternate methods.
§ 60.8(c)–(f)	Conducting performance tests.	No..	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No..	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)..	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No..	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements.	No..	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

Subpart UUUUa—[Reserved]

■ 16. Remove and reserve subpart UUUUa.

■ 17. Add subpart UUUUb to read as follows:

Sec.

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

Introduction

§ 60.5700b What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish standards of performance limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. State plans under the emission guidelines in this subpart are also subject to the requirements of subpart Ba. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or Ba of this part, the requirements of this subpart shall apply.

§ 60.5705b Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases (GHG). The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from facilities regulated in the State plan, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the State plan, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from facilities regulated in the State plan, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to GHG emissions from facilities regulated in the State plan, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§ 60.5710b Am I affected by this subpart?

(a) If you are the Governor of a State in the contiguous United States with one or more affected EGUs that must be addressed in your State plan as indicated in § 60.5845b, you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no affected EGUs, or if all EGUs in your State are excluded from being affected EGUs per § 60.5850b, you must submit a negative declaration letter in place of the State plan.

(b) If you are a coal-fired steam generating unit that has demonstrated that it plans to permanently cease operation prior to January 1, 2032, consistent with § 60.5740b(a)(9)(ii), and that would be an affected EGU under these emissions guidelines but for § 60.5850b(k), you must comply with § 60.5876b.

§ 60.5715b What is the review and approval process for my State plan?

(a) The EPA will determine the completeness of your State plan submission according to § 60.27a(g). The timeline for completeness determinations is provided in § 60.27a(g)(1).

(b) The EPA will act on your State plan submission according to § 60.27a. The Administrator will have 12 months after the date the final State plan or State plan revision (as allowed under § 60.5790b) is found to be complete to fully approve, partially approve, conditionally approve, partially disapprove, and/or fully disapprove such State plan or revision or each portion thereof.

§ 60.5720b What if I do not submit a State plan or my State plan is not approvable?

(a) If you do not submit an approvable State plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved State plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a State plan replacing the relevant portion(s) of the Federal plan.

§ 60.5725b In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a State plan or a negative declaration letter (if applicable).

§ 60.5730b Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, consistent with the electronic submission requirements in § 60.5875b, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014, reconstruction on or before June 18, 2014, or modification on or before May 23, 2023, is found in your State, you will be found to have failed to submit a State plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a State plan.

State Plan Requirements

§ 60.5740b What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (13) of this section in your State plan submittal. The final State plan must meet the requirements and include the information required under § 60.5775b and must also meet any administrative and technical completeness criteria listed in § 60.27a(g)(2) and (3) that are not otherwise specifically enumerated here.

(1) *Identification of affected EGUs.* Consistent with § 60.25a(a), you must identify the affected EGUs covered by

your State plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845b. You must also identify the subcategory into which you have classified each affected EGU. States must subcategorize affected EGUs into one of the following subcategories:

(i) *Long-term coal-fired steam generating units,* consisting of coal-fired steam generating units that are not medium-term coal-fired steam generating units and do not plan to permanently cease operation before January 1, 2039.

(ii) *Medium-term 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, 2039.

(iii) *Base load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.

(iv) *Intermediate load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.

(v) *Low load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor less than 8 percent.

(vi) *Base load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.

(vii) *Intermediate load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.

(viii) *Low load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor less than 8 percent.

(2) *Inventory of Data from Affected EGUs.* You must include an inventory of the following data from the affected EGUs:

(i) The nameplate capacity of the affected EGU, as defined in § 60.5880b.

(ii) The base load rating of the affected EGU, as defined in § 60.5880b.

(iii) The data within the continuous 5-year period immediately prior to May 9, 2024 including:

(A) The sum of the CO_2 emissions during each quarter in the 5-year period.

(B) For affected EGUs in all subcategories except the low load natural gas- and oil-fired subcategories, the sum of the gross energy output during each quarter in the 5-year period; for affected EGUs in the low load natural gas- and oil-fired subcategories, the sum of the heat input during each quarter in the 5-year period.

(C) The heat input for each fuel type combusted during each quarter in the 5-year period.

(D) The start date and end date of the most representative continuous 8-quarter period used to determine the baseline of emission performance under § 60.5775b(d), the sum of the CO_2 mass emissions during that period, the sum of the gross energy output or, for affected EGUs in the low load natural gas-fired subcategory or low load oil-fired subcategory, the sum of the heat input during that period, and sum of the heat input for each fuel type combusted during that period.

(3) *Standards of Performance.* You must include all standards of performance for each affected EGU according to § 60.5775b. Standards of performance must be established at a level of performance that does not exceed the level calculated through the use of the methods described in § 60.5775b(b), unless a State establishes a standard of performance pursuant to § 60.5775b(e).

(4) *Requirements related to Subcategory Applicability.* (i) You must include the following enforceable requirements to establish an affected EGU's applicability for each of the following subcategories:

(A) For medium-term coal-fired steam generating units, you must include a requirement to permanently cease operations by a date after December 31, 2031, and before January 1, 2039.

(B) For steam generating units that meet the definition of natural gas- or oil-fired, and that either retain the capability to fire coal after May 9, 2024, that fired any coal during the 5-year period prior to that date, or that will fire any coal after that date and before January 1, 2030, you must include a requirement to remove the capability to fire coal before January 1, 2030.

(C) For each affected EGU, you must also estimate coal, oil, and natural gas usage by heat input for the first 3 calendar years after January 1, 2030.

(D) For affected EGUs that plan to permanently cease operation, you must include a requirement that each such affected EGU comply with applicable State and Federal requirements for permanently ceasing operation, including removal from its respective State's air emissions inventory and amending or revoking all applicable permits to reflect the permanent shutdown status of the EGU.

(5) *Increments of Progress.* You must include in your State plan legally enforceable increments of progress as required elements for affected EGUs in the long-term coal-fired steam generating unit and medium-term coal-fired steam generating unit subcategories.

(i) For affected EGUs in the long-term coal-fired steam generating unit subcategory using carbon capture to meet their applicable standard of performance and affected EGUs in the medium-term coal-fired steam generating unit subcategory using natural gas co-firing to meet their applicable standard of performance, State plans must assign calendar-date deadlines to each of the increments of progress described in subsection (a)(5)(i) and meet the website reporting obligations of subsection (a)(5)(iii):

(A) Submittal of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration for each affected EGU in the State plan.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or front-end engineering and design (FEED) study.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks the facility anticipates along the way.

(B) Completion of awarding of contracts. The owner or operator of an affected EGU can demonstrate compliance with this increment of progress by submitting sufficient evidence that the appropriate contracts have been awarded.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish boiler modifications.

(C) Initiation of on-site construction or installation of emission control equipment or process change.

(1) For each affected unit in the long-term coal-fired steam generating unit

subcategory, initiation of on-site construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, initiation of on-site construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(D) Completion of on-site construction or installation of emission control equipment or process change.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, completion of on-site construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, completion of on-site construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(E) Commencement of permitting actions related to pipeline construction. The owner or operator of an affected EGU must demonstrate that they have commenced permitting actions by a date specified in the State plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate each affected unit at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities.

(1) For affected units in the long-term coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts CCS to meet the standard of performance and ensure timely completion of CCS-related pipeline infrastructure.

(2) For affected units in the medium-term coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts natural gas co-firing to meet the standard of performance and ensures timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities.

(F) For each affected unit in the long-term coal-fired steam generating unit subcategory, a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities.

(G) Compliance with the standard of performance as follows:

(1) For each affected unit in the medium-term coal-fired subcategory, by January 1, 2030.

(2) For each affected unit in the long-term coal-fired steam generating subcategory, by January 1, 2032.

(ii) For any affected unit in the long-term coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than CCS or in the medium-term coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than natural gas co-firing:

(A) The State plan must include appropriate increments of progress consistent with 40 CFR 60.21a(h) specific to the affected unit's control strategy.

(1) The increment of progress corresponding to 40 CFR 60.21a(h)(1) must be assigned the earliest calendar date among the increments.

(2) The increment of progress corresponding to 40 CFR 60.21a(h)(5) must be assigned calendar dates as follows: for affected EGUs in the long-term coal-fired steam generating subcategory, no later than January 1, 2032; and for affected EGUs in the medium-term coal-fired steam generating subcategory, no later than January 1, 2030.

(iii) The owner or operator of the affected EGU must post within 30 business days of the State plan submittal a description of the activities or actions that constitute the increments of progress and the schedule for achieving the increments of progress on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10). As the calendar dates for each increment of progress occurs, the owner or operator of the affected EGU must post within 30 business days any documentation necessary to demonstrate that each increment of progress has been met on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10).

(iv) You must include in your State plan a requirement that the owner or operator of each affected EGU shall report to the State regulatory agency any deviation from any federally enforceable State plan increment of progress within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. This report must explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. You must also include in your State plan a requirement that the owner or operator of the affected EGU to post a report of any deviation from any federally enforceable increment of progress on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10) within 30 business days.

(6) *Reporting Obligations and Milestones for Affected EGUs that Have Demonstrated They Plan to Permanently Cease Operations.* You must include in your State plan legally enforceable reporting obligations and milestones for affected EGUs in the medium-term coal-fired steam generating unit (§ 60.5740b(a)(1)(ii)) subcategory, and for affected EGUs that invoke RULOF based on a unit's remaining useful life according to paragraphs (a)(6)(i) through (v) of this section:

(i) Five years before the date the affected EGU permanently ceases operations (either the date used to determine the applicable subcategory under these emission guidelines or the date used to invoke RULOF based on remaining useful life) or 60 days after State plan submission, whichever is later, the owner or operator of the affected EGU must submit an Initial Milestone Report to the applicable air pollution control agency that includes the information in paragraphs (a)(6)(i)(A) through (D) of this section:

(A) A summary of the process steps required for the affected EGU to permanently cease operations by the date included in the State plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit.

(B) A list of key milestones that will be used to assess whether each process step has been met, and calendar day deadlines for each milestone. These milestones must include at least the initial notice to the relevant reliability authority or authorities of an EGU's deactivation date and submittal of an official retirement filing with the EGU's relevant reliability authority or authorities.

(C) An analysis of how the process steps, milestones, and associated timelines included in the Milestone

Report compare to the timelines of similar EGUs within the State that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines.

(D) Supporting regulatory documents, which include those listed in paragraphs (a)(6)(i)(D)(*1*) through (*3*) of this section:

(1) Any correspondence and official filings with the relevant Regional Transmission Organization (RTO), Independent System Operator, Balancing Authority, Public Utilities Commission (PUC), or other applicable authority;

(2) Any deactivation-related reliability assessments conducted by the RTO or Independent System Operator;

(3) Any filings with the United States Securities and Exchange Commission or notices to investors, including but not limited to, those listed in paragraphs (a)(6)(i)(D)(*3*)(*i*) through (*v*) of this section.

(i) References in forms 10–K and 10–Q, in which the plans for the EGU are mentioned;

(ii) Any integrated resource plans and PUC orders approving the EGU's deactivation;

(iii) Any reliability analyses developed by the RTO, Independent System Operator, or relevant reliability authority in response to the EGU's deactivation notification;

(iv) Any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and

(v) Any notification to or from an RTO, Independent System Operator, or Balancing Authority altering the timing of deactivation for the EGU.

(ii) For each of the remaining years prior to the date by which an affected EGU has committed to permanently cease operations that is included in the State plan, the owner or operator of the affected EGU must submit an annual Milestone Status Report that includes the information in paragraphs (a)(6)(ii)(A) and (B) of this section:

(A) Progress toward meeting all milestones identified in the Initial Milestone Report, described in § 60.5740b(a)(6)(i); and

(B) Supporting regulatory documents and relevant SEC filings, including correspondence and official filings with the relevant RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority to demonstrate compliance with or progress toward all milestones.

(iii) No later than six months from the date the affected EGU permanently ceases operations (either the date used to determine the applicable subcategory under these emission guidelines or the date used to invoke RULOF based on remaining useful life), the owner or operator of the affected EGU must submit a Final Milestone Status Report. This report must document any actions that the EGU has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(iv) The owner or operator of the affected EGU must post their Initial Milestone Report, as described in paragraph (a)(6)(i) of this section; annual Milestone Status Reports, as described in paragraph (a)(6)(ii) of this section; and Final Milestone Status Report, as described in paragraph (a)(6)(iii) of this section; including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the Carbon Pollution Standards for EGUs website required by paragraph (a)(10) of this section within 30 business days of being filed.

(v) You must include in your State plan a requirement that the owner or operator of each affected EGU shall report to the State regulatory agency any deviation from any federally enforceable State plan reporting milestone within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. This report must explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. You must also include in your State plan a requirement that the owner or operator of the affected EGU to post a report of any deviation from any federally enforceable reporting milestone on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10) within 30 business days.

(7) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your State plan all applicable monitoring, reporting and recordkeeping requirements, including initial and ongoing quality assurance and quality control procedures, for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860b.

(8) *State reporting.* You must include in your State plan a description of the process, contents, and schedule for State reporting to the EPA about State plan implementation and progress.

(9) *Specific requirements for existing coal-fired steam generating EGUs.* Your State plan must include the requirements in paragraphs (a)(9)(i) through (iii) of this section specifically for existing coal-fired steam generating EGUs:

(i) Your State plan must require that any existing coal-fired steam-generating EGU shall operate only subject to a standard of performance pursuant to § 60.5775b or under an exemption of applicability provided under § 60.5850b (including any extension of the date by which an EGU has committed to cease operating pursuant to the reliability assurance mechanism, described in paragraph (a)(13) of this section).

(ii) You must include a list of the coal-fired steam generating EGUs that are existing sources at the time of State plan submission and that plan to permanently cease operation before January 1, 2032, and the calendar dates by which they have committed to cease operating.

(iii) The State plan must provide that an existing coal-fired steam generating EGU operating past the date listed in the State plan pursuant to paragraph (a)(9)(ii) of this section is in violation of that State plan, except to the extent the existing coal-fired steam generating EGU has received an extension of its date for ceasing operation pursuant to the reliability assurance mechanism, described in paragraph (a)(13) of this section.

(10) *Carbon Pollution Standards for EGUs Websites.* You must require in your State plan that owners or operators of affected EGUs establish a publicly accessible ''Carbon Pollution Standards for EGUs Website'' and that they post relevant documents to this website. You must require in your State plan that owners or operators of affected EGUs post their subcategory designations and compliance schedules as well as any emissions data and other information needed to demonstrate compliance with a standard of performance to this website in a timely manner. This information includes, but is not limited to, emissions data and other information relevant to determining compliance with applicable standards of performance, information relevant to the designation and determination of compliance with increments of progress and reporting obligations including milestones for affected EGUs that plan to permanently cease operations, and any extension requests made and

granted pursuant to the compliance date extension mechanism or the reliability assurance mechanism. Data should be available in a readily downloadable format. In addition, you must establish a website that displays the links to these websites for all affected EGUs in your State plan.

(11) *Compliance Date Extension*. You may include in your State plan provisions allowing for a compliance date extension for owners or operators of affected EGU(s) that are installing add-on controls and that are unable to meet the applicable standard of performance by the compliance date specified in § 60.5740b(a)(4)(i) due to circumstances beyond the owner or operator's control. Such provisions may allow an owner or operator of an affected EGU to request an extension of no longer than one year from the specified compliance date and may only allow the owner or operator to receive an extension once. The optional State plan mechanism must provide that an extension request contains a demonstration of necessity that includes the following:

(i) A demonstration that the owner or operator of the affected EGU cannot meet its compliance date due to circumstances beyond the owner or operator's control and that the owner or operator has met all relevant increments of progress and otherwise taken all steps reasonably possible to install the controls necessary for compliance by the specified compliance date up to the point of the delay. The demonstration shall:

(A) Identify each affected unit for which the owner or operator is seeking the compliance extension;

(B) Identify and describe the controls to be installed at each affected unit to comply with the applicable standard of performance pursuant to § 60.5775b;

(C) Describe and demonstrate all progress towards installing the controls and that the owner or operator has itself acted consistent with achieving timely compliance, including:

(1) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable; and

(2) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(D) Identify the circumstances that are entirely beyond the owner or operator's control and that necessitate additional time to install the identified controls. This may include:

(1) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in § 60.5740b(a)(4)(i);

(2) Documentation of any permit delays; or

(3) Documentation of delays in construction or permitting of infrastructure (*e.g.*, CO_2 pipelines) that is necessary for implementation of the control technology;

(E) Identify a proposed compliance date no later than one year after the applicable compliance date listed in § 60.5740b(a)(4)(i) and, if necessary, updated calendar dates for the increments of progress that have not yet been met.

(ii) The State air pollution control agency is charged with approving or disapproving a compliance date extension request based on its written determination that the affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraphs (a)(11)(i)(A) through (E) of this section. The following provisions for approval must be included in the mechanism:

(A) All documentation required as part of this extension must be submitted by the owner or operator of the affected EGU to the State air pollution control agency no later than 6 months prior to the applicable compliance date for that affected EGU.

(B) The owner or operator of the affected EGU must notify the relevant EPA Regional Administrator of their compliance date extension request at the time of the submission of the request.

(C) The owner or operator of the affected EGU must post their application for the compliance date extension request to the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10), when they submit the request to the State air pollution control agency.

(D) The owner or operator of the affected EGU must post the State's determination on the compliance date extension request to the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10), upon receipt of the determination and, if the request is approved, update the information on the website related to the compliance date and increments of progress dates within 30 days of the receipt of the State's approval.

(12) *Short-Term Reliability Mechanism*. You may include in your State plan provisions for a short-term reliability mechanism for affected EGUs in your State that operate during a system emergency, as defined in § 60.5880b. Such a mechanism must include the components listed in paragraphs (a)(12)(i) through (vi) of this section.

(i) A requirement that the short-term reliability mechanism is available only during system emergencies as defined in § 60.5880b. The State plan must identify the entity or entities that are authorized to issue system emergencies for the State.

(ii) A provision that, for the duration of a documented system emergency, an impacted affected EGU may comply with an emission limitation corresponding to its baseline emission performance rate, as calculated under § 60.5775b(d), in lieu of its otherwise applicable standard of performance. The State plan must clearly identify the alternative emission limitation that corresponds to the affected EGU's baseline emission rate and include it as an enforceable emission limitation that may be applied only during periods of system emergency.

(iii) A requirement that an affected EGU impacted by the system emergency and complying with an alternative emission limitation must provide documentation, as part of its compliance demonstration, of the system emergency according to (a)(12)(iii)(A) through (D) of this section and that it was impacted by that system emergency.

(A) Documentation that the system emergency was in effect from the entity issuing the system emergency and documentation of the exact duration of the event;

(B) Documentation from the entity issuing the system emergency that the system emergency included the affected source/region where the unit was located;

(C) Documentation that the source was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside of its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/RTO; and

(D) Data collected during the event including the sum of the CO_2 emissions, the sum of the gross energy output, and the resulting CO_2 emissions performance rate.

(iv) A requirement to document the hours an affected EGU operated under a system emergency and the enforceable emission limitation, whether the applicable standard of performance or the alternative emission limitation, under which that affected EGU operated during those hours.

(v) A provision that, for the purpose of demonstrating compliance with the applicable standard of performance, the affected EGU would comply with its baseline emissions rate as calculated under § 60.5775b(d) in lieu of its otherwise applicable standard of performance for the hours of operation that correspond to the duration of the event.

(vi) The inclusion of provisions defining the short-term reliability mechanism must be part of the public comment process as part of the State plan's development.

(13) *Reliability Assurance Mechanism.* You may include provisions for a reliability assurance mechanism in your State plan. If included, such provisions would allow for one extension, not to exceed 12-months of the date by which an affected EGU has committed to permanently cease operations based on a demonstration consistent with this paragraph (a)(13) that operation of the affected EGU is necessary for electric grid reliability.

(i) The State plan must require that the reliability assurance mechanism would only be appliable to the following EGUs which, for the purpose of this paragraph (a)(13), are collectively referred to as ''eligible EGUs'':

(A) Coal-fired steam generating units that are exempt from these emission guidelines pursuant to § 60.5850b(k),

(B) Affected EGUs in the medium-term coal-fired steam-generating subcategory that have enforceable commitments to permanently cease operation before January 1, 2039, in the State plan, and

(C) Affected EGUs that have enforceable dates to permanently cease operation included in the State plan pursuant to § 60.24a(g).

(ii)The date from which an extension would run is the date included in the State plan by which an eligible EGU has committed to permanently cease operation.

(iii) The State plan must provide that an extension is only available to owners or operators of affected EGUs that have satisfied all applicable increments of progress and reporting obligations and milestones in paragraphs (a)(5) and (6) of this section. This includes requiring that the owner or operator of an affected EGU has posted all information relevant to such increments of progress and reporting obligations and milestones on the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10).

(iv) The State plan must provide that any applicable standard of performance for an affected EGU must remain in place during the duration of an extension provided under this mechanism.

(v) The State plan may provide for requests for an extension of up to 12 months without a State plan revision.

(A) For an extension of 6 months or less, the owner or operator of the eligible EGU requesting the extension must submit the information in paragraph (a)(13)(vi) to the applicable EPA Regional Administrator to review and approve or disapprove the extension request.

(B) For an extension of more than 6 months and up to 12 months, the owner or operator of the eligible EGU requesting the extension must submit the information in paragraph (a)(13)(vii) to the Federal Energy Regulatory Commission (through a process and at an office of the Federal Energy Regulatory Commission's designation) and to the applicable EPA Regional Administrator to review and approve or disapprove the extension request.

(vi) The State plan must require that to apply for an extension for 6 months or less, described in paragraph (a)(13)(v)(A) of this section, the owner or operator of an eligible EGU must submit a complete written application that includes the information listed in paragraphs (a)(13)(vi)(A) through (D) of this section no less than 30 days prior to the cease operation date, but no earlier than 12 months prior to the cease operation date.

(A) An analysis of the reliability risk that clearly demonstrates that the eligible EGU is critical to maintaining electric reliability. The analysis must include a projection of the length of time that the EGU is expected to be reliability-critical and the length of the requested extension must be no longer than this period or 6 months, whichever is shorter. In order to show an approvable reliability need, the analysis must clearly demonstrate that an eligible EGU ceasing operation by the date listed in the State plan would cause one or more of the conditions listed in paragraphs (a)(13)(vi)(A)(*1*) or (*2*) of this section. An eligible EGU that has received a Reliability Must Run designation, or equivalent from a Reliability Coordinator or Balancing Authority, would fulfill those conditions.

(*1*) Result in noncompliance with at least one of the mandatory reliability standards approved by FERC; or

(*2*) Would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, this requires a clear demonstration that the eligible EGU would be needed to maintain the targeted level of resource adequacy.

(B) Certification from the relevant reliability planning authority that the claims of reliability risk are accurate and that the identified reliability problem both exists and requires the specific relief requested. This certification must be accompanied by a written analysis by the relevant planning authority consistent with paragraph (a)(13)(vi)(A) of this section, confirming the asserted reliability risk if the eligible EGU was not in operation. The information from the relevant reliability planning authority must also include any related system-wide or regional analysis and a substantiation of the length of time that the eligible EGU is expected to be reliability critical.

(C) Copies of any written comments from third parties regarding the extension.

(D) Demonstration from the owner or operator of the eligible EGU, grid operator, and other relevant entities of a plan, including appropriate actions to bring on new capacity or transmission, to resolve the underlying reliability issue is leading to the need to employ this reliability assurance mechanism, including the steps and timeframes for implementing measures to rectify the underlying reliability issue.

(E) Any other information requested by the applicable EPA Regional Administrator or the Federal Energy Regulatory Commission.

(vii) The State plan must require that to apply for an extension longer than 6 months but up to 12 months, described in paragraph (a)(13)(v)(B) of this section, the owner or operator of an eligible EGU must submit a complete written application that includes the information listed in (a)(13)(vi)(A) through (E) of this section, except that the period of time under (a)(13)(vi)(A) would be 12 months. For requests for extensions longer than 6 months, this application must be submitted to the EPA Regional Administrator no less than 45 days prior to the date for ceasing operation listed in the State plan, but no earlier than 12 months prior to that date.

(viii) The State plan must provide that extensions will only be granted for the period of time that is substantiated by the reliability need and the submitted analysis and documentation, and shall not exceed 12 months in total.

(ix) The State plan must provide that the reliability assurance mechanism shall not be used more than once to extend an eligible EGU's planned cease operation date.

(x) The EPA Regional Administrator may reject the application if the submission is incomplete with respect to the requirements listed in paragraphs (a)(13)(vi)(A) through (E) of this section or if the submission does not adequately support the asserted reliability risk or the period of time for which the eligible EGU is anticipated to be reliability critical.

(b) [Reserved]

§ 60.5775b What standards of performance must I include in my State plan?

(a) For each affected EGU, your State plan must include the standard of performance that applies for the affected EGU. A standard of performance for an affected EGU may take the following forms:

(1) A rate-based standard of performance for an individual affected EGU that does not exceed the level calculated through the use of the methods described in § 60.5775b(c) and (d).

(2) A standard of performance in an alternate form, which may apply for affected EGUs in the long-term coal-fired steam generating unit subcategory or the medium-term coal-fired steam generating unit subcategory, as provided for in § 60.5775b(e).

(b) Standard(s) of performance for affected EGUs included under your State plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The State plan submittal must include the methods by which each standard of performance meets each of the following requirements:

(1) An affected EGU's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.

(2) An affected EGU's standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the standard of performance.

(3) An affected EGU's standard of performance is non-duplicative with respect to a State plan if it is not already incorporated as an standard of performance in the State plan.

(4) An affected EGU's standard of performance is permanent if the standard of performance must be met continuously unless it is replaced by another standard of performance in an approved State plan revision.

(5) An affected EGU's standard of performance is enforceable if:

(i) A technically accurate limitation or requirement, and the time period for the limitation or requirement, are specified;

(ii) Compliance requirements are clearly defined;

(iii) The affected EGUs are responsible for compliance and liable for violations identified;

(iv) Each compliance activity or measure is enforceable as a practical matter, as defined by 40 CFR 49.167; and

(v) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its standard of performance based on its emissions) and secure appropriate corrective actions: in the case of the Administrator, pursuant to CAA sections 113(a)–(h); in the case of a State, pursuant to its State plan, State law or CAA section 304, as applicable; and in the case of third parties, pursuant to CAA section 304.

(c) Methodology for establishing presumptively approvable standards of performance, for affected EGUs in each subcategory.

(1) Long-term coal-fired steam generating units

(i) BSER is CCS with 90 percent capture of CO_2.

(ii) Degree of emission limitation is 88.4 percent reduction in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an emission rate limit defined by an 88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.

(2) Medium-term coal-fired steam generating units

(i) BSER is natural gas co-firing at 40 percent of the heat input to the unit.

(ii) Degree of emission limitation is a 16 percent reduction in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an emission rate limit defined by a 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.

(iv) For units in this subcategory that have an amount of co-firing that is reflected in the baseline operation, States must account for such preexisting co-firing in adjusting the degree of emission limitation (*e.g.*, for an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 12 percent to reflect the preexisting level of natural gas co-firing).

(3) Base load oil-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,400 lb CO_2/MWh-gross.

(4) Intermediate load oil-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,600 lb CO_2/MWh-gross.

(5) Low load oil-fired steam generating units.

(i) BSER is uniform fuels.

(ii) Degree of emission limitation is 170 lb CO_2/MMBtu.

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 170 lb CO_2/MMBtu.

(6) Base load natural gas-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,400 lb CO_2/MWh-gross.

(7) Intermediate load natural gas-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,600 lb CO_2/MWh-gross.

(8) Low load natural gas-fired steam generating.

(i) BSER is uniform fuels.

(ii) Degree of emission limitation is 130 lb CO_2/MMBtu.

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 130 lb CO_2/MMBtu.

(d) Methodology for establishing the unit-specific baseline of emission performance.

(1) A State shall use the CO_2 mass emissions and corresponding electricity

generation or, for affected EGUs in the low load oil- or natural gas-fired subcategory, heat input data for a given affected EGU from the most representative continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to May 9, 2024.

(2) For the continuous 8 quarters of data, a State shall divide the total CO_2 emissions (in the form of pounds) over that continuous time period by either the total gross electricity generation (in the form of MWh) or, for affected EGUs in the low load oil- or natural gas-fired subcategory, total heat input (in the form of MMBtu) over that same time period to calculate baseline CO_2 emission performance in lb CO_2 per MWh or lb CO_2 per MMBtu.

(e) Your State plan may include a standard of performance in an alternate form that differs from the presumptively approvable standard of performance specified in § 60.5775b(a)(1), as follows:

(1) An aggregate rate-based standard of performance (lb CO_2/MWh-gross) that applies for a group of affected EGUs that share the same owner or operator, as calculated on a gross generation weighted average basis, provided the standard of performance meets the requirements of paragraph (f) of this section.

(2) A mass-based standard of performance in the form of an annual limit on allowable mass CO_2 emissions for an individual affected EGU, provided the standard of performance meets the requirements of paragraph (g) of this section.

(3) A rate-based standard of performance (lb CO_2/MWh-gross) implemented through a rate-based emission trading program, such that an affected EGU must meet the specified lb CO_2/MWh-gross rate that applies for the affected EGU, and where an affected EGU may surrender compliance instruments denoted in 1 short ton of CO_2 to adjust its reported lb CO_2/MWh-gross rate for the purpose of demonstrating compliance, provided the standard of performance meets the requirements of paragraph (h) of this section.

(4) A mass-based standard of performance in the form of an annual CO_2 budget implemented through a mass-based CO_2 emission trading program, where an affected EGU must surrender CO_2 allowances in an amount equal to its reported mass CO_2 emissions, provided the standard of performance meets the requirements of paragraph (i) of this section.

(f) Where your State plan includes a standard of performance in the form of an aggregate rate-based standard of performance (lb CO_2/MWh-gross) that applies for a group of affected EGUs that share the same owner or operator, as calculated on a gross generation weighted average basis, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section, to each of the affected EGUs that form the group.

(2) Documentation of any assumptions underlying the calculation of the aggregate rate-based standard of performance (lb CO_2/MWh-gross).

(3) The process for calculating the aggregate gross generation weighted average emission rate (lb CO_2/MWh-gross) at the end of each compliance period, based on the reported emissions (lb CO_2) and utilization (MWh-gross) of each of the affected EGUs that form the group.

(4) Measures to implement and enforce the annual aggregate rate-based standard of performance, including the basis for determining owner or operator compliance with the aggregate standard of performance and provisions to address any changes to owners or operators in the course of implementation.

(5) A demonstration of how the application of the aggregate rate-based standard of performance will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(g) Where your State plan includes a standard of performance in the form of an annual limit on allowable mass CO_2 emissions for an individual affected EGU, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply to the affected EGU under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) The utilization level used to calculate the mass CO_2 limit, by multiplying the assumed utilization level (MWh-gross) by the presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross), including the underlying data used for the calculation and documentation of any assumptions underlying this calculation.

(3) Measures to implement and enforce the annual limit on mass CO_2 emissions, including provisions that address assurance of achievement of equivalent emission performance.

(4) A demonstration of how the application of the mass CO_2 limit for the affected EGU will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(5) The backstop rate-based emission rate requirement (lb CO_2/MWh-gross) that will also be applied to the affected EGU on an annual basis.

(6) For affected EGUs in the long-term coal-fired steam generating unit subcategory, in lieu of paragraphs (g)(2), (4), and (5) of this section, you may include a presumptively approvable mass CO_2 limit based on the product of the rate-based standard of performance (lb CO_2/MWh-gross) under paragraph (a)(1) of this section multiplied by a level of utilization (MWh-gross) corresponding to an annual capacity factor of 80 percent for the individual affected EGU with a backstop rate-based emission rate requirement equivalent to a reduction in baseline emission performance of 80 percent on an annual calendar-year basis.

(h) Where your State plan includes a standard of performance in the form of a rate-based standard of performance (lb CO_2/MWh-gross) implemented through a rate-based emission trading program, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that applies to each of the affected EGUs participating in the rate-based emission trading program under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) Measures to implement and enforce the rate-based emission trading program, including the basis for awarding compliance instruments (denoted in 1 ton of CO_2) to an affected EGU that performs better on an annual basis than its rate-based standard of performance, and the process for demonstration of compliance that includes the surrender of such compliance instruments by an affected EGU that exceeds its rate-based standard of performance.

(3) A demonstration of how the use of the rate-based emission trading program will achieve equivalent or better emission reduction as would be achieved through the application of a

rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(i) Where your State plan includes a mass-based standard of performance implemented through a mass-based CO_2 emission trading program, where an affected EGU must surrender CO_2 allowances in an amount equal to its reported mass CO_2 emissions, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply to each affected EGU participating in the trading program under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) The calculation of the mass CO_2 budget contribution for each participating affected EGU, determined by multiplying the assumed utilization level (MWh-gross) of the affected EGU by its presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross), including the underlying data used for the calculation and documentation of any assumptions underlying this calculation.

(3) Measures to implement and enforce the annual budget of the mass-based CO_2 emission trading program, including provisions that address assurance of achievement of equivalent emission performance.

(4) A demonstration of how the application of the CO_2 emission budget for the group of participating affected EGUs will achieve equivalent or better emission performance as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply to each participating affected EGU under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(5) The backstop rate-based emission rate requirement (lb CO_2/MWh-gross) that will also be applied to each participating affected EGU on an annual basis.

(j) In order to use the provisions of § 60.24a(e) through (h) to apply a less stringent standard of performance or longer compliance schedule to an affected EGU based on consideration of electric grid reliability, including resource adequacy, under these emission guidelines, a State must provide the following with its State plan submission:

(1) An analysis of the reliability risk clearly demonstrating that the particular affected EGU is critical to maintaining electric reliability such that requiring it to comply with the applicable requirements under paragraph (c) of this section or § 60.5780b would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission or would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, a clear demonstration is required that the particular affected EGU would be needed to maintain the targeted level of resource adequacy. The analysis must also include a projection of the period of time for which the particular affected EGU is expected to be reliability critical and substantiate the basis for applying a less stringent standard of performance or longer compliance schedule consistent with 40 CFR 60.24a(e).

(2) An analysis by the relevant reliability planning authority that corroborates the asserted reliability risk identified in the analysis under paragraph (j)(1) of this section and confirms that requiring the particular affected EGU to comply with its applicable requirements under paragraph (c) of this section or § 60.5780b would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission or would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region, and also confirms the period of time for which the EGU is projected to be reliability critical.

(3) A certification from the relevant reliability planning authority that the claims of reliability risk are accurate and that the identified reliability problem both exists and requires the specific relief requested.

§ 60.5780b What compliance dates and compliance periods must I include in my State plan?

(a) The State plan must include the following compliance dates:

(1) For affected EGUs in the long-term coal-fired subcategory, the State plan must require compliance with the applicable standards of performance starting no later than January 1, 2032, unless the State has applied a later compliance date pursuant to § 60.24a(e) through (h).

(2) For affected EGUs in the medium-term coal-fired subcategory, the base load oil-fired subcategory, the intermediate load oil-fired steam generating subcategory, the low load oil-fired subcategory, the base load natural gas-fired subcategory, the intermediate load natural gas-fired subcategory, and the low load natural gas-fired subcategory, the State plan must require compliance with the applicable standards of performance starting no later than January 1, 2030, unless State has applied a later compliance date pursuant to § 60.24a(e) through (h).

(b) The State plan must require affected EGUs to achieve compliance with their applicable standards of performance for each compliance period as defined in § 60.5880b.

§ 60.5785b What are the timing requirements for submitting my State plan?

(a) You must submit a State plan or a negative declaration letter with the information required under § 60.5740b by May 11, 2026.

(b) You must submit all information required under paragraph (a) of this section according to the electronic reporting requirements in § 60.5875b.

§ 60.5790b What is the procedure for revising my State plan?

EPA-approved State plans can be revised only with approval by the Administrator. The Administrator will approve a State plan revision if it is satisfactory with respect to the applicable requirements of this subpart and all applicable requirements of subpart Ba of this part. If one (or more) of State plan elements in § 60.5740b require revision, the State must submit a State plan revision pursuant to § 60.28a.

§ 60.5795b Commitment to review emission guidelines for coal-fired affected EGUs

EPA will review and, if appropriate, revise these emission guidelines as they apply to coal-fired steam generating affected EGUs by January 1, 2041. Notwithstanding this commitment, EPA need not review these emission guidelines if the Administrator determines that such review is not appropriate in light of readily available information on their continued appropriateness.

Applicability of State Plans to Affected EGUs

§ 60.5840b Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State, except as provided in § 60.5710b(b). However, affected EGU owners or operators must comply with the State plan that a State develops to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a State plan to implement and enforce the standards of performance contained in this subpart by May 11, 2026, or the EPA disapproves State plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720b, applicable to each affected EGU within the State.

§ 60.5845b What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your State plan are:

(1) Any affected EGUs that were in operation or had commenced construction on or before January 8, 2014;

(2) Coal-fired steam generating units that commenced a modification on or before May 23, 2023.

(b) An affected EGU is a steam generating unit that meets the relevant applicability conditions specified in paragraphs (b)(1) through (2) of this section, as applicable, except as provided in § 60.5850b.

(1) Serves a generator capable of selling greater than 25 MW to a utility power distribution system; and

(2) Has a base load rating (*i.e.*, design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

§ 60.5850b What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) New or reconstructed steam generating units that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date;

(b) Modified natural gas- or oil-fired steam generating units that are subject to subpart TTTT of this part as a result of commencing modification after the subpart TTTT applicability date;

(c) Modified coal-fired steam generating units that are subject to subpart TTTTa of this part as a result of commencing modification after the subpart TTTTa applicability date;

(d) EGUs subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh;

(e) Non-fossil fuel units (*i.e.*, units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(f) CHP units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater;

(g) Units that serve a generator along with other EGUs, where the effective generation capacity (determined based on a prorated output of the base load rating of each EGU) is 25 MW or less;

(h) Municipal waste combustor units subject to 40 CFR part 60, subpart Eb;

(i) Commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or

(j) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

(k) Existing coal-fired steam generating units that have demonstrated that they plan to permanently cease operations before January 1, 2032, pursuant to § 60.5740b(a)(9)(ii).

Recordkeeping and Reporting Requirements

§ 60.5860b What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my State plan for affected EGUs?

(a) Your State plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (9) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet standards of performance must prepare a monitoring plan in accordance with the applicable provisions in 40 CFR 75.53(g) and (h), unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to 40 CFR part 75.

(2) For rate-based standards of performance, only "valid operating hours,", *i.e.*, full or partial unit (or stack) operating hours for which:

(i) "Valid data" (as defined in § 60.5880b) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; data obtained from flow monitoring bias adjustments are not considered to be valid data; and data provided or not provided from monitoring instruments that have not met the required frequency for relative accuracy audit testing are not considered to be valid data and

(ii) The corresponding hourly gross energy output value is also valid data (Note: For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based standards of performance, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.*, carbon capture and storage (CCS)), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.*, from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(ii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2

concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6), if required by a State plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to 40 CFR part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D to 40 CFR part 75, as applicable.

(ii) For each measured hourly heat input rate, use Equation G–4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6), if required by a State plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to 40 CFR part 75 and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(5) For rate-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis gross electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain, and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with gross electric output to determine gross energy output. The owner or operator must use the following procedures to calculate gross energy output, as appropriate for the type of affected EGU(s).

(i) Determine $P_{gross/net}$ the hourly gross or net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.*, full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate $P_{gross/net}$ for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output value reported under 40 CFR part 75 to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(iv)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

$P_{GROSS/NET}$ = Gross or net energy output of your affected EGU for each valid operating hour (as defined in 60.5860b(a)(2)) in MWh.

$(PE)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(PE)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(PE)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected egu's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(PE)_{A}$ = Electric energy used for any auxiliary loads in MWh.

$(PT)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(V) of this section in MWh.

$(PT)_{HR}$ = Non-steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(PT)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric transmission and distribution factor of 0.95 for a combined heat and power affected egu where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consist of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

Equation 2 to Paragraph (a)(5)(v)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

Q_M = Measured steam flow in kilograms (KG) (or pounds (LBS)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in joules per kilogram (J/KG) (or BTU/LB).

CF = Conversion factor of 3.6×10^9 J/MWH or 3.413×10^6 BTU/MWh.

(vi) For rate-based standards, sum all of the values of $P_{gross/net}$ for the valid operating hours (as defined in paragraph (a)(2) of this section). Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the $P_{gross/net}$ values for the valid operating hours to determine the CO_2 emissions rate (lb/gross or net MWh).

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly gross or net electric output for the common stack must be the sum of the hourly gross or net electric output of the individual affected EGUs and the operating time must be expressed as "stack operating hours" (as defined in 40 CFR 72.2).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the "stack operating time" (as defined in 40 CFR 72.2) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the gross or net energy output for the affected EGU.

(8) Consistent with § 60.5775b, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(9) The owner or operator of an affected EGU must measure and report monthly fuel usage for each affected source subject to standards of performance with the information in paragraphs (a)(9)(i) through (iii) of this section:

(i) The calendar month during which the fuel was used;

(ii) Each type of fuel used during the calendar month of the compliance period; and

(iii) Quantity of each type of fuel combusted in each calendar month in the compliance period with units of measure.

(b) Your State plan must require the owner or operator of each affected EGU covered by your State plan to maintain the records, for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's standard of performance under § 60.5775b.

(ii) Copies of all reports submitted to the State under paragraph (b) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(c) Your State plan must require the owner or operator of an affected EGU covered by your State plan to include in a report submitted to you the information in paragraphs (c)(1) through (3) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour;

(ii) The gross or net electric output and the gross or net energy output ($P_{gross/net}$) values for each valid operating hour;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour;

(iv) The sum of the hourly gross or net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours; and

(v) The calculated CO_2 mass emission rate (lbs/gross or net MWh).

(3) For each affected EGU the report must also include the applicable standard of performance and demonstration that it met the standard of performance. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate in units of the standard of performance.

(d) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a State plan that are required under § 60.5740b if applicable.

(e) If an affected EGU captures CO_2 to meet the applicable standard of performance, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from the EPA pursuant to paragraph (f) of this section.

(f) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5865b What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of State plan components, State plan requirements, supporting documentation, and the status of meeting the State plan requirements defined in the State plan.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that are used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860b.

(c) If your State has a requirement for all hourly CO_2 emissions and gross generation or heat input information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in 40 CFR part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records for a minimum of 10 years from the date the record is used to determine compliance with an emissions standard or State plan requirement. Each record must be in a form suitable and readily available for expeditious review.

(e) If your State plan includes provisions for the compliance date extension, described in § 60.5740b(a)(11), you must keep records of the information required in § 60.5740b(a)(11)(i) from affected EGUs that use the compliance date extension.

(f) If your State plan includes provisions for the short-term reliability mechanism, as described in § 60.5740b(a)(12), you must keep records of the information required in § 60.5740b(a)(12)(iii) from affected EGUs that use the short-term reliability mechanism.

(g) If your State plan includes provisions for the reliability assurance mechanism, described in § 60.5740b(a)(13), you must keep records of the information required in § 60.5740b(a)(13)(vi) from affected EGUs that use the reliability assurance mechanism.

§ 60.5870b What are my reporting and notification requirements?

(a) In lieu of the annual report required under § 60.25(e) and (f), you must report the information in paragraph (b) of this section.

(b) You must submit an annual report to the EPA that must include the information in paragraphs (b)(1) through (10) of this section. For each calendar year reporting period the report must be submitted by March 1 of the following year.

(1) The report must include the emissions performance achieved by each affected EGU during the reporting period and identification of whether each affected EGU is in compliance with its standard of performance during the compliance period, as specified in the State plan.

(2) The report must include, for each affected EGU, a comparison of the CO_2 standard of performance in the State plan versus the actual CO_2 emission performance achieved.

(3) The report must include, for each affected EGU, the sum of the CO_2 emissions, the sum of the gross energy output, and the sum of the heat input for each fuel type.

(4) Enforcement actions initiated against affected EGUs during the reporting period, under any standard of performance or compliance schedule of the State plan.

(5) Identification of the achievement of any increment of progress required by the applicable State plan during the reporting period.

(6) Identification of designated facilities that have ceased operation during the reporting period.

(7) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of State plan development but began operation during the reporting period.

(8) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(9) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

(10) The report must include all other required information, as specified in your State plan according to § 60.5740b.

(c) If you include provisions for the compliance date extension, described in § 60.5740b(a)(11), in your State plan, you must report to the EPA the information listed in § 60.5740b(a)(11)(i).

(d) If you include provisions for the short-term reliability mechanism, described in § 60.5740b(a)(12), in your State plan, you must report to the EPA the following information for each event, listed in § 60.5740b(a)(12)(iii).

(e) If you include provisions for the reliability assurance mechanism, described in § 60.5740b(a)(13) in your State plan, you must report to the EPA the information listed in § 60.5740b(a)(13)(vi).

§ 60.5875b How do I submit information required by these emission guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All State plan submittals, supporting materials that are part of a State plan submittal, any State plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through the EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States that claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539–01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the May 11, 2026, deadline for State plan submittal so that the official will have the ability to submit the initial or final State plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization, and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all State plan components designated as federally enforceable must also be submitted in an editable version. Following initial State plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable State plan components, including State plan backstop measures. The editable copy of any such submitted State plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable State plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by the EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable State plan components. The editable copy of any such submitted State plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable State plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by the EPA.

§ 60.5876b What are the recordkeeping and reporting requirements for EGUs that have committed to permanently cease operations by January 1, 2032?

(a) If you are the owner or operator of an EGU that has committed to permanently cease operations by January 1, 2032, you must maintain records for and submit the reports listed in paragraphs (a)(1) through (3) of this section according to the electronic reporting requirements in paragraph (b) of this section.

(1) Five years before any planned date to permanently cease operations or by the date upon which the State plan is submitted, whichever is later, the owner or operator of the EGU must submit an initial report to the EPA that includes the information in paragraphs (a)(1)(i) and (ii) of this section.

(i) A summary of the process steps required for the EGU to permanently cease operation by the date included in the State plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. These process steps may include, *e.g.*, initial notice to the relevant reliability authority of the deactivation date and submittal of an official retirement filing (or equivalent filing) made to the EGU's relevant reliability authority.

(ii) Supporting regulatory documents, which include those listed in paragraphs (a)(1)(ii)(A) through (G) of this section:

(A) Correspondence and official filings with the relevant regional RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority;

(B) Any deactivation-related reliability assessments conducted by the RTO or Independent System Operator;

(C) Any filings pertaining to the affected EGU with the SEC or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which plans for the EGU are mentioned;

(D) Any integrated resource plans and PUC orders approving the EGU's deactivation;

(E) Any reliability analyses developed by the RTO, Independent System Operator, or relevant reliability authority in response to the EGU's deactivation notification;

(F) Any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and

(G) Any notification to or from an RTO, Independent System Operator, or relevant reliability authority altering the timing of deactivation of the EGU.

(2) For each of the remaining years prior to the date by which an EGU has committed to permanently cease operations, the owner or operator of the EGU must submit an annual status report to the EPA that includes the information listed in paragraphs (a)(2)(i) and (ii) of this section:

(i) Progress on each of the identified process steps identified in the initial report as described in paragraph (a)(1)(i) of this section; and

(ii) Supporting regulatory documents, including correspondence and official filings with the relevant RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority to demonstrate progress toward all steps described in paragraph (a)(1)(i) of this section.

(3) The owner or operator must submit a final report to the EPA no later than 6 months following its committed closure date. This report must document any actions that the EGU has taken subsequent to ceasing operation to

ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(b) Beginning November 12, 2024, if you are the owner or operator of an EGU that has committed to permanently cease operations by January 1, 2032, you must submit all the information required in paragraph (a) of this section in a Permanent Cessation of Operation report in PDF format following the procedures specified in paragraph (c) of this section.

(c) If you are required to submit notifications or reports following the procedure specified in this paragraph (c), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (c)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (c).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov*, and as described above, should include clear CBI markings and be flagged to the attention of the Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive P.O. Box 12055, RTP, NC 27711. All other files should also be sent to the attention of the Greenhouse Gas Emissions for Electric Utility Generating Units Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(d) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(e) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (e)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(f) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure*, you must meet the requirements outlined in paragraphs(f)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.*, hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.*, large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension

to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(g) Alternatives to any electronic reporting required by this subpart must be approved by the Administrator.

Definitions

§ 60.5880b What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A, Ba, TTTT, and TTTTa, of this part.

Affected electric generating unit or *Affected EGU* means a steam generating unit that meets the relevant applicability conditions in section § 60.5845b.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions, as defined below. For a stationary combustion turbine or IGCC, *base load rating* includes the heat input from duct burners.

Coal-fired steam generating unit means an electric utility steam generating unit or IGCC unit that meets the definition of ''fossil fuel-fired'' and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029, or that retains the capability to fire coal after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit,* (also known as ''cogeneration'') means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means an annual (calendar year) period for an affected EGU to comply with a standard of performance.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Nameplate capacity means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired,'' that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any calendar year after December 31, 2029.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to standard ambient temperature and pressure conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Oil-fired steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns oil for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

System Emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2, or its successor.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to 40 CFR part 75. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.4, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75 apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/ or heat.

[FR Doc. 2024–09233 Filed 5–8–24; 8:45 am]

BILLING CODE 6560–50–P

Appendix 2

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 24-1120 **September Term, 2023**

EPA-89FR39798

Filed On: July 19, 2024

State of West Virginia, et al.,

Petitioners

v.

Environmental Protection Agency and Michael S. Regan, Administrator, United States Environmental Protection Agency,

Respondents

Louisiana Public Service Commission, et al.,
Intervenors

Consolidated with 24-1121, 24-1122, 24-1124, 24-1126, 24-1128, 24-1142, 24-1143, 24-1144, 24-1146, 24-1152, 24-1153, 24-1155, 24-1222, 24-1226, 24-1227, 24-1233

BEFORE: Millett, Pillard, and Rao, Circuit Judges

O R D E R

Upon consideration of the motions for stay, the oppositions thereto, the replies, the Rule 28(j) letter, and the responses thereto; and the motions to participate as amici curiae and the lodged amicus briefs, it is

ORDERED that the motions of the Chamber of Commerce, the Sierra Club, the Environmental Defense Fund, and Professor Rachel Rothschild to participate as amici curiae be granted. The Clerk is directed to file the lodged amicus briefs. It is

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

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FURTHER ORDERED that the motions for stay be denied. Petitioners have not satisfied the stringent requirements for a stay pending this court's review. *See Nken v. Holder*, 556 U.S. 418, 434 (2009); D.C. CIRCUIT HANDBOOK OF PRAC. AND INTERNAL PROCS. 33 (2021).

On the merits, petitioners dispute whether the Environmental Protection Agency ("EPA") acted arbitrarily or capriciously in determining that carbon capture and other emission control technologies are adequately demonstrated, or that specific degrees of emission mitigation are achievable with those technologies. But petitioners have not shown they are likely to succeed on those claims given the record in this case. Nor does this case implicate a major question under *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), because EPA has claimed only the power to "set emissions limits under Section 111 based on the application of measures that would reduce pollution by causing the regulated source to operate more cleanly[,]" a type of conduct that falls well within EPA's bailiwick, *id.* at 2610.

On irreparable harm, actual compliance deadlines do not commence until 2030 or 2032—years after this case will be resolved. Though the first deadline for States to submit state implementation plans is May 2026, the only consequence of failing to submit a state plan is the promulgation of a federal plan—which the States can replace with their own plans later. EPA Opp., Ex. 1, Goffman Decl. ¶ 100. To the extent petitioners claim harm due to the need for long-term planning, a stay will not help because the risk remains that the distant deadlines in EPA's rule will come back into force at the end of the case.

EPA has suggested that this case be expedited as an alternative means of protecting all parties' interests. Accordingly, to ensure this case can be argued and considered as early as possible in the court's 2024 term, it is

FURTHER ORDERED that the parties submit, within 14 days from the date of this order, proposed formats and schedules for the briefing of these cases. The parties are strongly urged to submit a joint proposal and are reminded that the court looks with extreme disfavor on repetitious submissions and will, where appropriate, require a joint brief of aligned parties with total words not to exceed the standard allotment for a single brief. Whether the parties are aligned or have disparate interests, they must provide detailed justifications for any request to file separate briefs or to exceed in the

United States Court of Appeals
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aggregate the standard word allotment. Requests to exceed the standard word allotment must specify the word allotment necessary for each issue.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Selena R. Gancasz
Deputy Clerk

Appendix 3

NRECA
America's Electric Cooperatives

August 8, 2023

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

Submitted to the Federal eRulemaking Portal, www.regulations.gov

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); 88 Fed. Reg. 33,240 (May 23, 2023)

Dear Administrator Regan,

The National Rural Electric Cooperative Association (NRECA) respectfully submits these comments in response to the U.S. Environmental Protection Agency's (EPA, or the Agency) Proposed Rules to limit greenhouse gas (GHG) emissions from new and existing fossil fuel-fired electric generating units (EGUs).[1] NRECA is the national trade association representing 900 not-for-profit electric cooperatives and other rural electric utilities.

America's electric cooperatives are owned by the people they serve and comprise a unique sector of the electric industry. Electric cooperatives power one in eight Americans and serve as engines of economic development for 42 million people across 56% of the nation's landscape. Electric cooperatives are focused on providing affordable, reliable, and safe electric power in an environmentally responsible manner and support common sense solutions to environmental impacts.

NRECA appreciates the opportunity to comment on the Proposed Rules.[2] These comments are accompanied by several technical comments and reports that NRECA attaches to this submission and cites throughout.[3] These documents should be considered in their entirety.

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[1] 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) (Proposed Rules).

[2] NRECA is also a member of the Power Generators Air Coalition that submitted comments on this proposal.

[3] These documents are: *Appendix: Response to EPA Comment Solicitation Regarding Carbon Storage and Transportation*. **(Carbon Storage Appendix)**; *Examination of EPA's Proposed Emission Guidelines Under 40 CFR Part 60*. University of North Dakota Energy & Environmental Research Center. **(EERC)**; *Analysis of Post Combustion CO_2 Capture, Transport and Storage Costs in the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule*. William Morris and John Weeda. **(Morris and Weeda CCS)**; *Analysis of EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on The Generation Alternative of Fuel Switching to Natural Gas*. William Morris and John Weeda. **(Morris and Weeda Natural Gas)**; *Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on Generation Resource Adequacy and the Need for Transmission Alternatives*. John Weeda. **(Weeda)**; *Analysis of the National Energy Technology Laboratory Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy*. Doug Campbell. **(Campbell**

For the reasons explained in these comments, and detailed in the accompanying attachments, EPA should withdraw the Proposed Rules. To put it simply, the proposals exceed EPA's statutory authority and would jeopardize affordable and reliable electricity by mandating nascent, inadequately demonstrated technologies and unachievable emissions limits on an unworkable timeframe.

I. Executive Summary

America's not-for-profit electric cooperatives are committed to keeping the lights on at a cost local families and businesses can afford. This commitment to providing affordable, reliable, and safe electricity underpins NRECA's comments to EPA's proposal. Electric cooperatives operate without shareholders and are uniquely affected by regulatory mandates. Any increased costs for cooperatives must be passed along directly to their consumer-members at the end of the line. It is therefore critical that agencies issue regulations that are cost effective.

EPA's Proposed Rules would require the use of technologies that are not commercially viable on an unreasonably expedited timeframe. Under the Clean Air Act (CAA), EPA's standards must be adequately demonstrated, achievable, and cost effective. Its proposed best systems of emission reduction in the form of carbon capture and storage (CCS), co-firing clean hydrogen, or co-firing natural gas all fail to meet these criteria. Accordingly, the Proposed Rules clearly violate the CAA and go beyond clear limitations established by Supreme Court precedent.

CCS is a nascent but promising technology, and NRECA and its members have been leaders in its development. But it has not been shown to work at a commercial scale on either coal or natural gas units, and certainly not at the 90% capture rate that the Agency proposes. It is also heavily reliant on outside the fence line infrastructure that does not currently exist and will not exist by the proposed compliance dates. Clean hydrogen is even further behind CCS in its development. There is currently no supply of clean hydrogen to meet EPA's standards. Like CCS, there is also no infrastructure in place to transport or store it, even if it was available in the needed amounts. There are also substantial limitations to currently using clean hydrogen as a steady, ongoing fuel source for combustion turbines, making EPA's proposed co-firing levels based on conjecture and aspiration. And while natural gas co-firing is used by some coal units, it is not available to many units due to location, access, or engineering considerations.

EPA couples these inadequately demonstrated technologies with unworkable timelines that will be impossible to achieve. The Agency also substantially underestimates what it would cost to comply – assuming compliance is even possible. As a result, the always available generation that will be necessary to meet the increasing electrification needs of the future will be forced to retire. These retirements will pose direct threats to electric grid reliability that EPA fails to appropriately assess and inaccurately models. Accordingly, EPA should withdraw the Proposed Rules in their entirety.

NETL); *Analysis of Hydrogen in Combustion Turbine Electric Generating Units*. **(Campbell Hydrogen)**; *Analysis of EPA's Proposed Construction Timeframes for CCS Projects*. Daniel Walsh. **(Walsh)**; *Technical Comments on Hydrogen and Ammonia Firing*. Kiewit Engineering Group, Inc. **(Kiewit)**; *Technical Comments on the U.S. Environmental Protection Agency's Integrated Planning Model's Evaluation of the Greenhouse Gas Standards and Guidelines for Fossil Fuel-fired Power Plants – Proposed Rule*. James Marchetti. **(Marchetti Comments)**; *Technical Comments on the Carbon Capture Utilization and Sequestration Aspects of the Proposed 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*. J. Edward Cichanowicz and Michael C. Hein. **(Cichanowicz and Hein)**.

II. Background on NRECA and its Cooperative Members

The nation's member-owned, not-for-profit electric cooperatives constitute a unique sector of the electric utility industry. NRECA's member cooperatives include 63 generation and transmission (G&T) cooperatives and 832 distribution cooperatives. Each cooperative is governed by a board of directors elected from its membership. The G&Ts generate and transmit power to distribution cooperatives that provide it to the end of line cooperative consumer-members. Collectively, G&T cooperatives generate and transmit power to nearly 80% of distribution cooperatives, which in turn provide power directly to consumer-members at the end of the line.[4] The remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. Both distribution and G&T cooperatives share an obligation to serve their consumer-members by providing affordable, reliable, and safe electric service.

Furthermore, electric cooperatives rely on a diversity of resources that affordably and reliably meet their consumer-members' energy needs. Electric cooperatives are accelerating energy innovation to power a brighter future. Electric cooperatives continue to increase the use of renewable energy resources; add distributed energy resources and storage; adopt energy efficiency programs; monitor and explore developments related to nuclear energy; and work to enable electrification. These efforts are all made while balancing reliability at a time when energy demand is increasing.

Cooperatives have also been at the forefront of exploring carbon capture technologies. NRECA has supported research into the technology, and individual member cooperatives have helped by participating in federally backed research and development efforts. To illustrate this commitment to affordable, reliable, and low emissions power, in 2021, two-thirds of the electricity delivered by cooperatives came from low- or zero-carbon sources.[5]

A. Cost-effective regulations are critical to America's electric cooperatives.

Cost-effective federal regulations that minimize unnecessary burdens are very important to cooperatives' ability to provide affordable, reliable and safe electricity to their consumer-members. Rural electric cooperatives serve large expanses of the United States that are primarily residential and typically sparsely populated. Those characteristics make it comparatively more expensive for rural electric cooperatives to operate than the rest of the electric sector, which traditionally serves more compact, industrialized, and densely populated areas.

Since electric cooperatives serve areas with low population density, costs are borne across a base of fewer consumers and by families that spend more of their limited resources on electricity than do comparable municipal-owned or investor-owned utility customers. Using data from the U.S. Energy Information Administration (EIA) and other sources, NRECA estimates that rural electric cooperatives serve an average of eight consumers per mile of line and collect annual revenue of approximately $19,000 per mile of line. In contrast, for the rest of the industry, the averages are 32 customers and $79,000 in annual revenue per mile of line.

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[4] Cooperatives own and maintain 2.7 million miles, or 42%, of the nation's electric distribution lines. NRECA, *America's Cooperative Electric Utilities Fact Sheet*. p. 2. March 2, 2023. Available at: https://www.cooperative.com/programs-services/bts/Documents/Data/Electric-Co-op-Fact-Sheet.pdf.

[5] In 2021, electric cooperatives' fuel mix included 22% renewables, 15% nuclear, 29% natural gas, 32% coal, and 2% oil and other resources. National Rural Electric Cooperative Association. *Electric Co-op Facts and Figures*. April 13, 2023. (NRECA Fact Sheet) Available at: https://www.electric.coop/electric-cooperative-fact-sheet.

Many cooperative consumer-members are among those least able to afford higher electricity rates. In 2022, the average (mean) household income for electric cooperative consumer-members was 12% below the national average. That is unsurprising, given that electric cooperatives serve 92% of persistent poverty counties in the United States.[6]

More generally, the electricity supplied by rural cooperatives is vital to rural economies and an essential element of modern residential, rural life. Rural development requires access to affordable and reliable electric power. Regulations that are not cost-effective and increase the cost of producing that electricity, or threaten its availability, thus pose serious threats to maintenance and growth in large segments of rural America.

Electric cooperatives have no equity shareholders who can bear the costs of stranded generation assets or investment in new or alternative generation resources. Cooperatives do not have a rate of return on equity as do investor-owned utilities because cooperatives operate on a not-for-profit basis. For that reason, all costs are passed through directly to their consumer-members that already spend more of their limited incomes on electricity. Consequently, electric cooperatives must ultimately pass along capital costs directly to their consumer-members through increased electric rates.

Given that cooperatives maintain only marginal cash reserves for anticipated operating expenses and unforeseen events, financing for many capital projects necessarily require reliance on debt sourced from entities such as the United States Department of Agriculture's (USDA) Rural Utilities Service, National Rural Utilities Cooperative Finance Corporation, and CoBank. The costs of borrowing, too, are necessarily passed on to cooperatives' consumer-members. Ultimately, then, it is the cooperatives' consumer-members at the end of the line who bear the cost of regulations through increased electric rates.

All but two of NRECA's member cooperatives are "small entities" under the U.S. Small Business Administration's (SBA) size standards. By virtue of their size and limited resources, small entities such as cooperatives are disproportionately burdened by the cost of regulations in comparison to their larger counterparts. Cost-effective federal regulations that minimize unnecessary burdens are very important to cooperatives' ability to provide affordable, reliable, and safe electricity to their consumer-members. For that reason, it is extremely important that EPA comply with the Regulatory Flexibility Act (RFA) and properly assess the costs of the Proposed Rules on small entities, work to reduce any disproportionate burdens, and provide compliance flexibility.

B. Policy decisions and other challenges are threatening the reliable delivery of electricity in the United States.

Providing affordable, reliable, and safe electricity is paramount for electric cooperatives. A resilient and reliable electric grid that affordably keeps the lights on is the cornerstone of American social, economic, energy security, and national security needs. However, the United States is facing a number of challenges to maintaining reliable electricity. In addition to the Proposed Rules, a series of EPA regulations are being issued in rapid succession with the outcome of making it too costly and difficult to operate always available, fossil fuel-fired power plants, threatening the stability of America's electric grid.[7]

[6] NRECA Fact Sheet at 1.

[7] These actions include: Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18,824 (March 29, 2023); National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 88 Fed. Reg. 24,854 (April 24, 2023); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric

As a nation, we are heading towards a future that depends on electricity to power more of the economy. Recent modeling by the Electric Power Research Institute concluded that achieving net-zero economy-wide emissions by 2050 could require generation capacity to increase by as much as 480% compared to what is in place today.[8] Electrifying other sectors of the economy could require a three-fold expansion of the transmission grid and up to 170% more electricity supply by 2050, according to the National Academies of Sciences.[9]

While the United States' electricity demand is increasing, policy decisions are driving always available power plants to retire at too rapid a pace without adequate replacement capacity. The North American Electric Reliability Corporation's (NERC) recent reliability assessments have "pointed to the disorderly retirement of traditional generation (with its inherent ability to provide essential reliability services and balance energy reserves) as one of the biggest challenges facing the grid."[10] NERC's 2023 Summer Reliability Assessment shows that two-thirds of North America is at elevated risk of energy shortfalls this summer due to conventional generation retirements, a substantial increase in forecast peak demand, and an increasing threat from a wide-spread heat event.[11] That assessment also identifies EPA's recently finalized ozone transport rule as one that will exacerbate these reliability challenges.[12]

In a recent report, PJM, the regional transmission organization (RTO) that serves parts of 13 states and the District of Columbia, identified three EPA regulations – the steam electric effluent limitations guidelines rule, the coal combustion residuals rule, and the ozone transport rule – as ones that have "the potential to result in a significant amount of generation retirements within a condensed time frame."[13] Reiterating the point during a recent Senate hearing, PJM CEO Manu Asthana said that "we need to hang on to resources that we have today that work, until their replacement is here" and that the Proposed Rules "will continue to push this generation off the grid."[14]

Completing federal environmental reviews and obtaining permits for infrastructure projects also takes too long and is another challenge to build new electric generating assets and other electric infrastructure, including transmission lines that would be required to replace the reliable, dispatchable power retired as a result of the Proposed Rules. On average, it takes federal agencies more than four years simply to complete

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Utilities; Legacy CCR Surface Impoundments, 88 Fed. Reg. 31,982 (May 18, 2023); and Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023).

[8] Electric Power Research Institute. *LCRI Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis, Executive Summary*. Last updated March 9, 2023. Available at: https://lcri-netzero.epri.com/en/executive-summary.html.

[9] National Academies of Sciences, Engineering, and Medicine. *Accelerating Decarbonization of the U.S. Energy System*. 2021. Available at https://nap.nationalacademies.org/catalog/25932/accelerating-decarbonization-of-the-us-energy-system.

[10] North American Electric Reliability Corporation. *2022 Annual Report*. February 2023. p.13. Available at: https://www.nerc.com/gov/Annual%20Reports/NERC_Annual%20Report_2022.pdf.

[11] North American Electric Reliability Corporation. *2023 Summer Reliability Assessment Infographic*. May 2023. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA%20Infographic_2023.pdf; and *2023 Summer Reliability Assessment*. May 2023. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

[12] *Id.* at 6.

[13] PJM. *Energy Transition in PJM: Resource Retirements, Replacements, &* Risks. February 24, 2023. p. 7. (Energy Transition in PJM) Available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx. PJM's analysis shows that a total of 40 gigawatts (GW) of existing generation are at risk of retirement by 2030, including 25 GW of potential policy-driven retirements. *Id.* p. 2.

[14] Senate Committee on Energy & Natural Resources. *Full Committee Hearing to Examine the Reliability and Resiliency of Electric Services in the U.S. in Light of Recent Reliability Assessments and Alerts*. Held June 1, 2023. Video of hearing available at: https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts.

the environmental review process, while one quarter of projects take more than six years.[15] And those timelines do not account for litigation that may ensue, further delaying the needed infrastructure projects. While important reforms to the National Environmental Policy Act (NEPA) were recently enacted, more must be done to increase the efficiency of the federal environmental review and permitting process, which can involve multiple agencies depending on the federal permits, authorizations, and other approvals required for a project.[16] Unfortunately, the federal environmental review process is being made more complex and less efficient by policies that are being pursued by this administration.[17]

On top of these difficulties, electric utilities are facing significant challenges and delays in their supply chains, which are contributing to an unprecedented shortage of the most basic machinery and components essential to ensuring continued reliability of the electric grid. Electric cooperatives are waiting a year, on average, to receive distribution transformers. Additionally, lead times for large power transformers have grown to more than three years. And orders for electrical conduit have been delayed five-fold to 20 weeks, with costs ballooning by 200% year-over-year. As a result, new projects are being deferred or canceled, and electric cooperatives and other electric utilities are concerned about their ability to respond to major storms due to depleted stockpiles. In addition, utilities are facing natural gas shortages, which can cause particularly acute challenges during periods of peak demand.[18]

All of these challenges pose a serious threat to electric reliability, and federal agencies – in particular EPA – should be considering how their regulations increase reliability risks and how they can avoid exacerbating those risks. In fact, Section 111 of the CAA requires EPA to do so.[19] Unfortunately, EPA has not adequately assessed the impact of the Proposed Rules, nor the cumulative impacts of the several recent Agency actions mentioned above, on electric reliability.

C. Electric cooperatives are carbon capture and storage leaders.

Electric cooperatives are among the national leaders exploring the development of CCS. NRECA is proud to be sponsoring partners of the National Carbon Capture Center and the Wyoming Integrated Test Center (ITC). In addition to the important research efforts that take place at these facilities, in geographic locations

[15] *Environmental Impact Statement Timelines (2010-2018)*. Executive Office of the President, Council on Environmental Quality. June 12, 2020. p. 4. Available at: https://ceq.doe.gov/docs/nepa-practice/CEQ_EIS_Timeline_Report_2020-6-12.pdf; *see also 2022 Annual NEPA Report of the National Environmental Policy Act Working Group*. National Association of Environmental Professionals. July 2022. Available at: https://naep.memberclicks.net/assets/annual-report/NEPA_Annual_Report_2022.pdf. In 2022, the average preparation time for a final EIS, as measured from notice of intent to final EIS, was 4.2 years.

[16] *Federal Environmental Review and Authorization Inventory*. March 2023. Available at: https://www.permits.performance.gov/tools/federal-environmental-review-and-authorization-inventory-excel.

[17] *See, e.g.*, National Rural Electric Cooperative Association Comments on the Bureau of Land Management's Proposed Rule on Conservation and Landscape Health (July 5, 2023), BLM-2023-0001-152650, https://www.regulations.gov/comment/BLM-2023-0001-152650; Comments of the National Rural Electric Cooperative Association and the American Public Power Association on the Council on Environmental Quality's National Environmental Policy Act Interim Guidance on Consideration of Greenhouse Gas Emissions and Climate Change (April 10, 2023), CEQ-2022-0005-0307, https://www.regulations.gov/comment/CEQ-2022-0005-0307; Comments of the Utility Water Act Group in Response to US Army Corps of Engineers and Environmental Protection Agency Proposed Rule on Revised Definition of "Waters of the United States" (Feb. 7, 2022), EPA-HQ-OW-2021-0602-0601, https://www.regulations.gov/comment/EPA-HQ-OW-2021-0602-0601.

[18] Letter from Gordon van Welie, President and Chief Exec. Officer, ISO New England to the Hon. Jennifer Granholm, Secretary, U.S. Department of Energy. August 29, 2022. Available at: https://www.iso-ne.com/static-assets/documents/2022/08/isone_energy_security_letter_to_us_doe_and_statement_for_ferc_winter_forum_2022_08_29.pdf. (Describing the challenges New England faces as it requires natural gas generation to sustain reliability, particularly as policymakers seek to increase electrification, and how the region's lack of sufficient pipeline infrastructure and uncertainty surrounding the global market for liquefied natural gas has the potential to stress electric grid reliability).

[19] *See* 42 U.S.C. § 7411(a) (1) (Requiring EPA take "nonair quality health and environmental impact and *energy requirements*" into account when setting standards).

where it is feasible and makes sense for cooperative consumer-members to do so, NRECA's members are actively engaged in the deployment of CCS as an emerging technology.

Minnkota Power Cooperative's Milton R. Young Station will be the site of Project Tundra, a carbon capture project to retrofit the North Dakota coal-fired plant with an amine-based solvent technology. The captured carbon dioxide (CO_2) will be stored more than a mile underground and accompanied by extensive sequestration monitoring. The project, originally conceived in 2015 and currently in the engineering phase with operation anticipated by 2028, will capture CO_2 from one of the Young Station's two units and is expected to be the world's largest CCS facility when complete.

Basin Electric Power Cooperative's coal-fired Dry Fork plant is the host site for the ITC and is adjacent to the University of Wyoming's CarbonSAFE CO_2 storage project. The ITC is a public-private partnership that includes support from Basin, NRECA, and Tri-State Generation and Transmission Association. Dry Fork provides the equivalent of 20 megawatts (MW) of flue gas to the ITC, which provides space for researchers to test CCS technologies. Some of the first tenants were teams competing for the NRG COSIA Carbon XPRIZE. Dry Fork is also the host site for a commercial-scale engineering and design study to incorporate a capture system using membrane technology.

Golden Spread Electric Cooperative's natural gas-fired Mustang Station was the subject of a University of Texas at Austin CO_2 capture feasibility study. The front-end engineering and design study assessed an advanced post-combustion CO_2 scrubbing process with solvent regeneration for the West Texas plant.

Wabash Valley Power Alliance, Southern Illinois Power Cooperative, and Prairie Power are part owners of the Prairie State Energy Campus, which has partnered with the University of Illinois on a CO_2 capture retrofit front-end engineering and design study for the southern Illinois coal-fired plant.

The Nebraska Public Power District, which sells power to Nebraska Electric Generation & Transmission Cooperative, is working with technology experts to evaluate CO_2 capture and storage for its coal-fired Gerald Gentleman Station. Evaluations are underway to assess the technical, geographic, regulatory, and financial viability of CO_2 capture and geologic storage.

CCS is a nascent but promising technology, and NRECA and its cooperative members have supported its development through advocacy in support of various federal incentives. NRECA has long supported the Section 45Q tax credits for CO_2 sequestration, including increased values and direct payment options for not-for-profit entities enacted as part of the Inflation Reduction Act (IRA). NRECA has also supported Department of Energy (DOE) CCS program reauthorizations and funding, including provisions in the Energy Act of 2020, Infrastructure Investment and Jobs Act (IIJA), and annual appropriations bills. This includes DOE CO_2 capture pilot and demonstration programs and grant funding, established through amendments to the Energy Policy Act of 2005. Additionally, NRECA supported inclusion of CO_2 capture projects as an eligible use of loans, grants, and other financial assistance under the IRA's Empowering Rural America program established at the USDA.

Presently, however, even with these various federal incentives, CCS is not yet a commercially available, adequately demonstrated technology for deployment at a national scale, and certainly not at the capture rates required by EPA's Proposed Rules and not on any compliance timeline contemplated by the Agency.

III. EPA Lacks Authority for the Proposed Standards Under the Plain Language of the Clean Air Act and the "Major Questions" Doctrine.

The Proposed Rules are unlawful because they are inconsistent with the text, structure, and context of CAA Section 111. For the first time, the authority to set performance standards is based on what the Agency believes the future of the sector *could* be instead of what "*has been* adequately demonstrated" and is *actually* "achievable" today. EPA's unlawful interpretation of the CAA, should it stand, would totally reshape the power sector and would have enormous implications for the entire United States' social, economic, energy security, and national security needs.

In addition to exceeding its authority under the CAA, the Proposed Rules plainly run afoul of the "major questions" doctrine, which holds that an agency lacks authority to make such decisions of "vast economic and political significance" without a clear statement from Congress, which is lacking here.[20]

Section 111 simply cannot bear the weight that EPA places on it. EPA's authority under Section 111 must be understood within the context of the overall regulatory framework that Congress enacted. For stationary sources, Congress developed three programs that work together to control emissions: (1) the National Ambient Air Quality Standards Program under Section 110, (2) the Hazardous Air Pollutants Program under Section 112, and (3) the New Source Performance Standards Program (NSPS) under Section 111.

The National Ambient Air Quality Standards Program is the primary means by which EPA, in cooperation with the states, may regulate air emissions. Section 110 requires EPA to set ambient air concentration levels for pollutants "reasonably anticipated to endanger public health and welfare" at the "maximum airborne concentration of [the] pollutant that the public health can tolerate."[21] The states then have primary responsibility to implement the standards to ensure attainment of EPA's health and welfare driven standards.

The Hazardous Air Pollutants Program, Section 112, in turn, mandates technology-based standards designed to reduce risks from pollutants that cause acute and chronic disease. Under Section 112, EPA sets standards for each separate source category responsible for emitting those pollutants.[22] EPA sets those emissions reduction standards based on "the maximum degree of reduction in emissions...that, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, [EPA] determines is achievable" through application of control technology.[23]

In contrast, and as the Supreme Court has explained, Section 111 serves an "ancillary" role to the other two stationary source programs.[24] Both Sections 110 and 112 are goal oriented. They focus on achieving ambient air quality concentrations necessary to protect public health and welfare and establishing emissions reductions that protect the public from illness and disease. Section 111, in contrast, provides a "gap filler" to "regulate harmful emissions not already controlled under the Agency's other authorities."[25] It is focused not on setting robust aspirational standards that would transform the electric sector, but rather ensuring pollutants not directly addressed by the primary, health-based standards, are limited to levels achieved by the best

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[20] *Utility Air Regulatory Group v. EPA*, 573. U.S. 302, 324 (2014); *West Virginia v. EPA*, 597 U.S. at __, 142 S. Ct. 2587, 2605 (2022).
[21] *Whitman v. Am. Trucking Ass'ns, Inc.*, 531 U.S. 457, 565 (2001), 42 U.S.C. § 7409.
[22] 42 U.S.C. § 7412(d)(1).
[23] 42 U.S.C. § 7412(d)(2).
[24] *West Virginia*, 142 S. Ct. at 2602.
[25] *Id.* at 2601.

already-demonstrated technology.[26] That is why the Supreme Court, in striking down EPA's previous attempt to claim vast authority under Section 111, explained that the statute is generally limited to proven measures "that would reduce pollution by causing the regulated source to operate more cleanly."[27] EPA may not require "generation shifting," impose a cap-and-trade program, or force a nationwide transition away from coal or natural gas as a source of electricity.[28] Such authority involves "major questions" of economic and political significance that require a clear statement from Congress.[29]

But EPA is now moving down a road almost identical to the one the Supreme Court rejected. EPA's proposed standards seek to shift the nation away from fossil fuel-fired generation toward energy sources the Agency prefers by setting standards that are unachievable, based on technology that has not been adequately demonstrated, and that are so unproven and aspirational that they require premature closure and/or shifting of generation to another source of generation more favorable to EPA.

For example, under the proposal, if an electric cooperative wants to continue to operate a coal-fired unit past 2040, it must meet emissions limits, beginning in 2030, that are based on the reductions EPA believes CCS will be able to accomplish in the future. But, as discussed in Section IV, while CCS is a promising technology, it is not available to most units today, certainly not at the 90% capture rate EPA would require and will not be available in 2030, particularly absent the necessary pipeline and storage infrastructure which similarly will not be available in that timeframe. In the alternative to this impossible-to-meet standard, EPA would allow coal units to (1) commit to retirement by 2032, (2) commit to retirement by 2035 and reduce their capacity factor to 20%, or (3) transform themselves into natural gas co-firing units. These are not measures to make the units operate more cleanly and is precisely the generation shifting the Supreme Court held that Section 111 did not authorize.[30]

EPA's proposed standards for gas-fired units similarly fail to adhere to Section 111's limitations. Existing gas-fired generating units would be restricted to operating at half of their capacity or would be required in 2032 to begin using "clean hydrogen," i.e., hydrogen produced through a process that has a GHG emissions rate of less than 0.45 kilograms of CO_2-equivalent per kilogram of hydrogen, at levels never before accomplished and that are unachievable. What is more, as described in Section IV, clean hydrogen does not and is not expected to exist in quantities anywhere near necessary to meet the demand for these units and would require construction of a nationwide hydrogen pipeline system that does not exist and will not exist by 2032. New gas-fired units fare no better. They can either limit operations to providing solely a supporting role to renewable generation or they can co-fire clean hydrogen at the same levels mandated for existing gas-fired plants – levels never before achieved or adequately demonstrated. Again, these are not measures to make units operate more cleanly; rather, they require a transformation of the electric sector.

As the Supreme Court has noted, it is "highly unlikely that Congress would leave to agency discretion the decision of how much coal-based generation there should be over the coming decades," let alone through "the previously little-used backwater of Section 111(d)."[31] EPA has never before required technology that is not yet ready and available, required changes in emissions rates or installation of technology years or even decades in the future, or promoted early retirement as a performance standard (except in the rule invalidated

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[26] 42 U.S.C. § 7411(a)(1), (b)(1), (d) (defining Section 111 standards as those that "reflects the degree of emission limitation achievable through the application of the best system of emission reduction which … the Administrator determines has been adequately demonstrated").
[27] *West Virginia*, 142 S. Ct. at 2596.
[28] *Id.* at 2596.
[29] *Id.*
[30] *Id.* at 2614-16.
[31] *Id.* at 2613 (citations and internal marks omitted).

by the Supreme Court).

Nothing in Section 111's text, structure, or context authorizes the sweeping authority that EPA claims through the Proposed Rules. In fact, the proposed standards are fundamentally flawed because they are unquestionably focused not on ensuring achievable standards of performance based on the best adequately demonstrated technology of today, but rather transforming the sector into EPA's aspirational view of what the future of electric generation might be. What EPA is attempting to achieve in the Proposed Rules is no less of a "major question" than what it attempted to achieve in the rule invalidated in *West Virginia. West Virginia* requires EPA to demonstrate that its authority to set standards based on technology and infrastructure that does not yet exist is clearly within the meaning of "achievable" and "has been adequately demonstrated." EPA has not done so.

In short, nothing in the CAA allows EPA to set future standards based on what it thinks the industry can accomplish in the future or to force retirements today in anticipation of that future. Had Congress intended for EPA to completely reshape the electric generating sector it would not have buried that authority in an "ancillary" provision of the CAA that focuses on technology that *has been* adequately demonstrated, and is achievable and cost effective today.

IV. The Proposed Rules Violate the Clean Air Act's Requirements for Setting Performance Standards.

A "standard of performance" under CAA Section 111 is one that "reflects the degree of emission limitation achievable through the application of the best system of emission reduction" which, after accounting for costs and "nonair quality health and environmental impact and energy requirements," EPA determines has been "adequately demonstrated."[32] Appropriately broken down to its elements, EPA must demonstrate that its proposed standards: (1) are based on technology that has been adequately demonstrated, (2) are achievable through application of that technology, and (3) are cost effective after considering costs and other nonair quality factors, including "energy requirements." The proposed standards fail each of these factors.

A. The performance standards are not based on technology that has been "adequately demonstrated."

An "adequately demonstrated" system is one that has an operational history showing more than mere technical feasibility.[33] The system must be commercially available, reliable, reasonably efficient, and not exorbitantly costly. Although EPA has some discretion to extrapolate from other industries when determining whether a technology demonstrated in one industry would be adequately demonstrated for another industry, that discretion is limited to narrow, technically sound extrapolation.[34] To be adequately demonstrated for all sources within a category or subcategory, a technology must be available for each source type to which the standard applies.[35]

[32] 42 U.S.C. § 7411(a)(1).
[33] *See Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-32 (D.C. Cir. 1973).
[34] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).
[35] *See* 70 Fed. Reg. 9,706, 9,712, 9,714, 9,715. (Rejecting certain technology as best system of emission reduction in part because of the unavailability of these options across source types to which the performance standards would apply).

1. Carbon capture and storage

The proposed standards for the CCS pathway have not been adequately demonstrated. Under the Proposed Rules, existing coal-fired units planning to operate beyond 2039 would need to achieve a 90% CO_2 capture rate by January 1, 2030. New natural gas units operating at baseload levels and existing natural gas units 300 MW or greater with at least a 50% capacity factor would have the option to comply by installing CCS at the same capture rate by January 1, 2035, or co-fire unproven and unavailable quantities of "clean hydrogen" (discussed below). To date, there are just two large-scale coal units with CCS, Boundary Dam Unit 3 and Petra Nova.[36] Of those, only Boundary Dam is currently operating – and not at levels that would comply with the Proposed Rules.[37] There are currently no natural gas units with CCS operating.[38]

None of the examples that serve as EPA's basis for showing adequate demonstration meet the definition under the statute. These 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 far below 90%."[39] Boundary Dam 3, one of the units EPA uses to assert that CCS is adequately demonstrated, captured just 44% of its emissions in 2021[40] and has consistently captured CO_2 at rates well below its 90% design capacity.[41] The other, Petra Nova, missed its capture targets by about 17%[42] and was plagued by issues that led to the unit being offline for more than a third of the time that it was operational before it was shut down in 2020.[43] It was eventually sold for a fraction of its initial investment.[44] To date there have been no sufficient demonstrations of CCS on natural gas units.[45]

EPA attempts to bolster its determination by citing *industrial* CCS applications to show that CCS is workable,[46] but as described above its legal authority to do so is narrow – and regardless is not relevant in this case since those applications typically involve higher concentrations of CO_2 in the exhaust gas and operate on a smaller scale than utility applications.[47] Utility applications have different challenges to address that make it unreasonable to try to extrapolate from industrial applications. [48]

As explained in detail in the Carbon Storage Appendix submitted as an attachment to these comments, EPA has also not adequately demonstrated that there will be sufficient transportation for CO_2 to potential storage locations, that these locations can be permitted in the timeframe EPA contemplates, or that sources are located close enough to storage locations to make transportation and storage feasible. EPA attempts to justify its speculation that there will be sufficient CO_2 transportation on the basis that the nation's CO_2 pipeline capacity "has steadily expanded, and appears primed to continue to do so," and that there have been recent

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[36] EERC at 5-6.
[37] *Id.* at 6-7
[38] *Id.* at 7-8.
[39] *Id.* at 5.
[40] Carlos Anchondo. *CCS 'red flag'? World's sole coal project hits snag.* Energywire. January 10, 2022. Available at: https://www.eenews.net/articles/ccs-red-flag-worlds-sole-coal-project-hits-snag/.
[41] EERC at 6.
[42] *Id.*
[43] Corbin Hiar and Carlos Anchondo. *Biggest CCS failure clouds Supreme Court ruling.* Climatewire. July 11, 2022. Available at: https://www.eenews.net/articles/biggest-ccs-failure-clouds-supreme-court-ruling/.
[44] Kyra Buckley. NRG sells stake in Petra Nova carbon capture project to Japanese company for $3.6 million. Houston Chronicle. September 20, 2022. Available at: https://www.houstonchronicle.com/business/energy/article/NRG-sells-stake-in-halted-carbon-capture-project-17454451.php.
[45] EERC at 5-8.
[46] 88 Fed. Reg. 33,292.
[47] Cichanowicz and Hein at 2-4.
[48] *Id.*

announcements of more than 3,000 new miles of pipeline under development.[49] Due to permitting challenges, public opposition to pipelines, and other obstacles, an announcement of pipelines does not mean they will be built.[50] The simple fact is that the current 5,300 miles of pipeline is less than one-tenth of what is needed, and the announcements will not come close to closing the gap in the timeframe EPA requires.[51] Even if these more than 3,000 miles get built, best estimates are that the nation would need 65,000 miles of CO_2 pipelines to meet the administration's clean energy goals.[52]

Further, EPA has not demonstrated its own ability to permit the necessary geologic storage. Its Class VI permitting program has only approved projects from two applicants since 2010 and there are currently several dozen applications that have been pending for years.[53] EPA believes it can increase the number of states that have been granted primacy, or primary enforcement authority, for Class VI storage in order to accelerate permitting. But it has not demonstrated an ability to act on state applications on a timeline consistent with the compliance requirements of the Proposed Rules, with only two states having been granted primacy. The Agency's drawn-out processing of primacy applications has disincentivized states from applying in the first place.[54] Even assuming more states were granted primacy, the rate of approvals has not demonstrated the ability to put enough geologic storage facilities in operation by 2030.[55]

EPA similarly fails to demonstrate that captured CO_2 can actually be sequestered as required by the Agency. The Agency arbitrarily assumes sources are located 100 kilometers (km) from a border of a state that has geologic storage.[56] This is puzzling, given there is real world data showing the actual locations of the power plants affected by the Proposed Rules. Regardless, being in a state that happens to be within 100 km of another state with storage would not mean that all affected units would only need to transport CO_2 100 km to sequester it.[57] Nor would it mean that the average distance from affected units to a storage location is 100 km. The closest geologic storage locations may not end up viable for storing CO_2 after site characterization, and even if they are viable and can be permitted in time, may be far from the state border on which EPA arbitrarily bases its distance.[58]

2. Clean hydrogen

The clean hydrogen pathway is not adequately demonstrated. Under the Proposed Rules, new natural gas units operating at baseload levels and existing natural gas units 300 MW or greater with at least a 50% capacity factor that are unable or opt not to install CCS would have the option to comply by co-firing clean hydrogen at 30% starting on January 1, 2032, and increasing to 96% on January 1, 2038.

Foremost, no unit has reached hydrogen co-firing at the levels EPA proposes.[59] Despite forecasted development of turbines that will run at 30% blends, none are demonstrated nor commercially available with guaranteed performance today to be a viable option to meet the EPA's proposed requirements.[60] The only basis for EPA's proposed phase 3 requirement – co-firing clean hydrogen at 96% by volume – is

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[49] 88 Fed. Reg. 33,293-33,294.
[50] Cichanowicz and Hein at 23-29.
[51] Princeton University. *Net-Zero America: Potential Pathways, Infrastructure, and Impacts. Final Report.* October 29, 2021.
[52] *Id.*
[53] Carbon Storage Appendix at 14-16.
[54] *Id.*
[55] *Id.*
[56] 88 Fed. Reg. 33,298.
[57] Carbon Storage Appendix at 17-18.
[58] *Id.* at 7-17.
[59] Campbell Hydrogen at 4-5.
[60] *Id.*

manufacturer aspirations about what they hope to make in the future.[61] A National Energy Technology Laboratory (NETL) white paper describes major obstacles to overcome before those aspirations become reality.[62] Those obstacles include dealing with hydrogen's higher flame temperature and faster flame speed, which can cause issues with injectors and other turbine components.[63] EPA has failed to present meaningful real world data that would resolve those obstacles.

EPA also has not demonstrated that there is or will be adequate access to clean hydrogen. The Agency simply assumes that IRA and IIJA incentives will lead to sufficient supply.[64] This assertion is highly speculative, as the regulations defining clean hydrogen for the purposes of the IRA's incentives are not finalized – and have proved controversial.[65] EPA's speculation about the future of this fuel cannot demonstrate, let alone guarantee, sufficient clean hydrogen by the 2032 compliance date.

The only technology to produce low-GHG hydrogen as required under the Proposed Rules that may come to be viable at scale in that time frame is electrolysis.[66] But today, electrolysis is not the method by which most hydrogen is produced. Steam methane reforming (SMR), which produces CO_2 and thus cannot be used for clean hydrogen (unless controlled with CCS), accounts for 95% of today's hydrogen production.[67] EPA fails to show that the challenges of creating a sufficient clean hydrogen supply, including that the electrolysis process requires far more electricity than will be yielded by the end product, the cost of production, and the amount of water necessary for the electrolysis process has been or will be overcome by the compliance deadline.[68]

Further, there is no infrastructure in place to deliver that hydrogen. There are currently just 1,600 miles of hydrogen pipeline in the United States,[69] and over 90% of this is located near the Gulf of Mexico.[70] As EPA notes in the preamble to the Proposed Rules, there are currently more than 3 million miles of pipelines connecting production areas with consumers.[71] EPA erroneously assumes the existing natural gas pipeline network can accommodate the clean hydrogen necessary at up to 5% to 15% by volume.[72] Yet at the same time EPA acknowledges a study for the National Renewable Energy Laboratory that "the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis."[73] EPA also acknowledges a study that shows that blending more hydrogen in gas pipelines overall results in a greater chance of pipeline leaks and the

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[61] Kiewit at 12-14.
[62] *Id.*
[63] *Id.*
[64] Environmental Protection Agency. *Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document*. May 23, 2023. pp. 37-38. (EPA Hydrogen TSD) Available at: https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20Hydrogen%20in%20Combustion%20Turbine%20EGUs.pdf.
[65] Nico Portuondo. *The coming Manchin-Biden feud over 'clean hydrogen.'* July 28, 2023. Available at: https://www.eenews.net/articles/the-coming-manchin-biden-feud-over-clean-hydrogen/.
[66] Campbell Hydrogen at 3-4.
[67] U.S. Department of Energy. *Hydrogen Production: Natural Gas Reforming*. (DOE Natural Gas Reforming) Available at: https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.
[68] Campbell Hydrogen at 3-4.
[69] U.S. Department of Energy. *Hydrogen Pipelines*. Accessed July 21, 2023. Available at: https://www.energy.gov/eere/fuelcells/hydrogen-pipelines..
[70] Congressional Research Service. *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy*. March 2, 2021. p. 5. Available at: https://crsreports.congress.gov/product/pdf/R/R46700.
[71] 88 Fed. Reg. 33,352.
[72] EPA Hydrogen TSD at 26
[73] *Id.* at 26.

embrittlement of steel pipelines.[74] These issues will exacerbate existing permitting challenges and public opposition to pipelines.[75]

In order to accommodate the amount of hydrogen that would be necessary, a vast network of hydrogen pipelines would need to be constructed that is orders of magnitude larger than what exists today.[76] This is partly due to the fact that because of its low energy density, hydrogen would be impractical to transport by other means or store on site (thus making pipelines the only viable means of ready supply).[77] For example, it would take four acres of land to store one day's worth of hydrogen for a single GE H-class unit.[78] Further, the lower energy density of hydrogen compared to natural gas requires more quantity to provide the same generating capacity.[79] Hydrogen pipeline projects would likely encounter more substantial issues with delays than even CO_2 pipelines (or any pipelines for that matter) due to the highly explosive nature of hydrogen and other safety issues.[80] This contravenes EPA's speculation that the clean hydrogen pathway is achievable, since a pipeline network close to the size of the existing and expanding natural gas pipeline would need to be constructed on a timeline never before seen.

3. Natural gas co-firing at existing coal units

In order for the natural gas co-firing pathway to be adequately demonstrated, EPA has to show that all affected plants have access to a sufficient industrial natural gas supply and that there is sufficient pipeline capacity to fuel the level of conversions it contemplates. It does neither. EPA points to the existing natural gas infrastructure to indicate adequacy.[81] But its analysis overlooks the difficulties of constructing pipelines to units that do not currently have access to natural gas, including permitting delays and public opposition to pipelines.[82] According to EIA data, roughly 17% of coal-fired units nationwide are more than 10 miles from even the single nearest natural gas pipeline and nearly one-third are more than five miles.[83] But there is no guarantee that the closest pipeline will work for the unit in question – the pipeline might not have the capacity to accommodate an additional plant or unit.[84] EPA also fails to contemplate challenges in ensuring there is sufficient supply during certain weather events, as recent instances have shown make getting supply when needed difficult.[85]

4. Compliance lead times

The fact that the use of the proposed technology has not been adequately demonstrated is made altogether clear by the fact that EPA does not attempt to require its use until years or even decades in the future. But EPA has no authority to set standards far into the future based on what may be demonstrated and achievable then. Rather, Section 111 requires EPA to set standards and guidelines based on technology that *"has been* adequately demonstrated." Indeed, Congress specifically contemplated that EPA may revisit the new source

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[74] *Id.* at 25.
[75] *See* Cichanowicz and Hein at 23-29 (Discussion of public opposition of pipelines generally) and Kiewit at 18-19 (Discussion of safety challenges of hydrogen pipelines).
[76] Kiewit at 19-20.
[77] *Id.* at 16-17.
[78] *Id.* at 16.
[79] *Id.* at 9-10.
[80] *Id.* at 19.
[81] 88 Fed. Reg. 33,352.
[82] *See* Morris and Weeda Natural Gas at 5 (Citing Energy Information Administration data on the lack of natural gas availability); and Cichanowicz and Hein at 23-29 (Discussing public opposition to pipelines).
[83] *EIA Energy Atlas Interactive Map*. Accessed July 19, 2023. Available at: https://atlas.eia.gov/apps/eia::all-energy-infrastructure-and-resources/explore.
[84] Morris and Weeda Natural Gas at 4-8.
[85] *Id.* at 4.

standards "every 8 years" to address evolving technology.[86] But EPA cannot lawfully act as prognosticator and set standards based on what it hopes will be adequately demonstrated in the future.

B. The proposed performance standards are not achievable.

EPA must demonstrate that the standards can be achieved by *all sources in the sector*, considering the variables that may affect emissions in different circumstances and at different plants.[87] To be "achievable," the technology must be reasonably available to new sources at the time they are constructed and for existing sources now.[88] The standards must "be capable of being met under most adverse conditions which can reasonably be expected to recur, and which are not or cannot be taken into account in determining the cost of compliance."[89] To that end, EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard."[90] Relatedly, EPA must demonstrate that the technology is available nationwide. That is, in order to be achievable, any new source in any state must be able to achieve that limit.[91] EPA may not base achievability on "mere speculation or conjecture" about what a technology may be capable of accomplishing.[92]

1. Carbon capture and storage

The proposed CCS pathway is not achievable. Units that would be covered by the Proposed Rules cannot achieve the capture rates that EPA proposes. According to the Proposed Rules, the requirement of a 90% capture rate is equivalent to an 88.4% emission reduction in coal units and an 89% emission reduction in natural gas units on an annual basis. Real world experience shows that even though units can be aspirationally designed to capture 90% or more of CO_2, the actual rates achieved are lower due to operational difficulties and availability of the capture unit.[93] EPA wrongly assumes capture systems are available 100% of the time that an EGU will be operational, but that assumption has been disproved by actual applications.[94]

EPA erroneously assumes that affected EGUs will have viable options to take captured CO_2 away from the plant site to be properly stored.[95] Unless an operator is blessed with viable storage under the footprint of a unit – as is the case with Minnkota's Project Tundra – CO_2 will have to be moved by pipeline. In contrast to Minnkota, when Arizona Electric Power Cooperative (AEPCO) investigated its options for CO_2 storage through the West Coast Regional Carbon Sequestration Partnership funded by DOE,[96] the project revealed there was insufficient permeability in the saline formations in the area studied. AEPCO also conducted a desktop study to evaluate the potential for proper sequestration and storage. That work concluded that the area does not provide the correct geologic formations suitable for this use at or near its only generating facility. It is likely that other cooperatives and electric utilities in similarly situated areas will not be able to

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[86] 42 U.S.C. § 7411(b)(1)(B).
[87] *See* 70 Fed. Reg. 9,706, 9,712, 9,714, 9,715. (Rejecting certain technology as best system of emission reduction in part because of the unavailability of these options across source types to which the performance standards would apply).
[88] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391-92 (D.C. Cir. 1973).
[89] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 n. 46 (D.C. Cir. 1980) (internal quotations omitted).
[90] *Sierra Club v. Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981) (citations omitted).
[91] *See Sierra Club*, 657 F.2d at 330 (water-dependent technology cannot be nationwide "best system" due to "disastrous" effects in arid west); *Nat'l Lime*, 627 F.2d at 441-43 (rejecting standards for failure to account for regional variability).
[92] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999).
[93] EERC at 6-7.
[94] *Id.*
[95] 88 Fed. Reg. 33,366.
[96] *See* https://www.westcarb.org/AZ_pilot_cholla.html.

find reasonably suitable geologic storage areas either, necessitating transportation over significant distance via pipeline.

While transporting CO_2 via pipeline may appear straightforward, the lack of infrastructure and storage currently available, and the long timeframes to develop storage locations, show otherwise. The costs associated with developing a pipeline will likely make it unachievable for many operators.[97] A thorough discussion of EPA's incorrect assumptions related to CO_2 storage and transportation is contained in the attached Carbon Storage Appendix. But it is worth mentioning just a few of the issues presented in that document to illustrate why CCS is not currently achievable.

There are two types of geologic storage available under the Proposed Rules: in oil and gas formations at an enhanced oil recovery (EOR) facility that reports under EPA's Greenhouse Gas Reporting Program, or by permanent geologic sequestration. The first option, known as Class II storage,[98] has a better track record of viability, but is too limited to be considered adequately demonstrated as it is only workable in certain areas of the country.[99] The second option, known as Class VI storage, similarly has geographic and technical constraints that render it unavailable to the majority of units in the country. That availability is vastly overstated by EPA.[100]

What is available has been hampered by EPA's glacial Class VI permitting program. In fact, only two applicants have had permits approved since the program began in 2010. There are currently several dozen pending applications.[101] Just two states – North Dakota and Wyoming – have been granted primacy allowing the state to run the program. EPA has been slow to act on these primacy applications – Louisiana originally filed an application in 2020 that has yet to be finalized.[102] Project applications in the rest of the states must be approved by EPA. The inability of applicants to obtain permits from either EPA or their state means that there will be an insufficient supply of storage locations available by the compliance date. Despite these difficulties in creating storage sites, and the fact that the only operational CO_2 storage facility for which EPA has issued a Class VI permit took roughly five years for site characterization alone,[103] EPA somehow projects it will take just two to three years to characterize and permit a storage facility.

EPA's assumption that sufficient storage capacity will somehow come online in the next seven years amounts to speculation that is unsupported by facts and history. Assuming a unit operator can capture CO_2, there are two business models available for storing it. The operator can either establish its own storage facility or contract with a storage provider. The second option is more likely as more plants use CCS because locating, developing, and operating carbon storage is a specialized competency not within the range of expertise of most unit operators. Further, most storage will be off site. There is currently, however, a lack of commercial storage options. Zero commercial Class VI storage sites exist that accept CO_2 from anyone other than the site's owner.[104] While NRECA expects that there will likely someday be more geologic storage options, they simply do not exist today, and there is no evidence they will exist by 2030 or on any other timeframe being considered by the Agency, rendering the proposed standards unachievable.

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[97] *See* Section IV.C.1 for a discussion of CO_2 pipeline costs.
[98] Defined under the Underground Injection Control program authorized by the Safe Drinking Water Act. Class II wells are specifically used for EOR applications, whereas Class VI wells are specifically used for deep saline aquifer storage of CO_2.
[99] Carbon Storage Appendix at 1.
[100] EERC at 8-10.
[101] Carbon Storage Appendix at 14-16.
[102] *Id.* at 15-16.
[103] *Id.* at 9-11.
[104] *Id.* at 17.

In reality, an estimated 65,000 miles of pipeline are needed to transport captured CO_2 to storage sites to achieve economy-wide net zero emissions by 2050.[105] Meanwhile, only 5,300 miles of pipeline currently exist.[106] Developing the needed pipeline network to cover even a portion of what is needed under the Proposed Rules is unachievable due to the difficulties and delays associated with pipeline construction, such as siting and permitting.[107]

2. Clean hydrogen

Like CCS, the clean hydrogen co-firing pathway is not achievable. Simply put, natural gas units cannot burn hydrogen at the levels contemplated by EPA. The newest units are designed to co-fire up to 30% hydrogen but have not been shown that they can do that continuously,[108] let alone for the remaining life of the unit. Even more egregious, EPA's assertion that 96% co-firing by 2038 is achievable is based on aspirational goals of combustion turbine manufacturers, not capability that exists today or at any time in the near future.[109] These assumptions are also based on entirely new units, not retrofits of existing units. There are significant design and engineering challenges that will make retrofit unworkable for some existing units.[110] This pathway is further unachievable because there is no indication clean hydrogen transportation and storage systems can be permitted and constructed in the timeframe EPA contemplates for the reasons described in the previous section.

Clean hydrogen – the specific type of hydrogen required under the Proposed Rules – is further unachievable because the state of current technology requires far more electricity to produce clean hydrogen than would result from using clean hydrogen as a fuel. For example, the energy required to produce enough clean hydrogen to fire a single LM6000 Simple Cycle Gas Turbine on 100% hydrogen is nearly four times the output power of that natural gas unit.[111]

Another reason the clean hydrogen pathway is unachievable is that there will not be sufficient clean hydrogen supply for units opting for this pathway on the timeline EPA has proposed. As discussed earlier, the Agency merely assumes that the IRA and the IIJA will provide the right mix of incentives to foster supply.[112] This is prognostication that does not guarantee, let alone demonstrate, that there will be sufficient clean hydrogen produced, particularly by the 2032 compliance date. Electrolysis is the only technology that could possibly come to scale in that timeframe, but that method currently accounts for just a fraction of total hydrogen production.[113] Rather, SMR, which produces CO_2 and thus would not meet EPA's proposed clean hydrogen standard without CCS, currently accounts for 95% of production.[114] A massive build out of electrolysis capability would be needed to meet EPA's Proposed Rules. But the current challenges of ramping up electrolysis, including the production process requiring far more electricity than will be produced by the end product, the cost of production, and the amount of water necessary for the production process, are not sufficiently accounted for by the Agency.[115] Nor are the challenges with the unprecedented infrastructure

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[105] Princeton University. *Net-Zero America: Potential Pathways, Infrastructure, and Impacts. Final Report.* October 29, 2021.
[106] Pipeline and Hazardous Materials Safety Administration. *Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems*. July 3, 2023. Accessed July 21, 2023. Available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-hazardous-liquid-or-carbon-dioxide-systems.
[107] Carbon Storage Appendix at 17-22.
[108] Campbell Hydrogen at 4.
[109] Kiewit at 12-14.
[110] *Id.* at 18.
[111] Campbell Hydrogen at 3-4.
[112] EPA Hydrogen TSD at 37-38.
[113] Campbell Hydrogen at 3.
[114] *See* DOE Natural Gas Reforming.
[115] Campbell Hydrogen at 3-4.

development that would need to take place in order for the hydrogen supply to reach operators, as discussed in the previous section. These challenges will have to be overcome to meet the Agency's proposed supply demands.

3. Natural gas co-firing at existing coal units

Similarly, the natural gas co-firing pathway for coal-fired EGUs retiring before 2040 is unachievable for many units. Fuel switching to natural gas is not practical for many generators due to lack of access to natural gas, even when there is a natural gas source nearby.[116] EPA's technical analysis of natural gas co-firing understates the engineering challenges associated with converting coal units to co-fire natural gas. While EPA acknowledges that the process involves an engineering analysis,[117] it fails to consider that in practice these analyses can reveal engineering challenges that are insurmountable.[118] As such, natural gas co-firing cannot be considered achievable for all affected units.

C. The proposed performance standards are not cost effective, especially after considering nonair quality factors and energy requirements.

EPA has also violated the CAA because the Proposed Rules are not cost-effective. After identifying adequately demonstrated, achievable technology that can be used by a source category to reduce emissions, EPA may select a performance standard that "represents the best balance of economic, environmental, and energy considerations."[119] EPA must consider cost and any nonair quality health and environmental impact and energy requirements, and in doing so, EPA must ensure that the standards do not give a competitive advantage to one state over another.[120]

Across the range of proposed compliance pathways, EPA has not considered the impact of increased demand on cost. As power plants attempt to comply, they will be competing for available material, equipment, land, and other resources. This competition for limited resources will necessarily drive prices higher over the implementation period. EPA acknowledges "demand for inputs by the electricity sector" in its regulatory impact analysis but does not demonstrate that costs were adjusted to reflect that increased demand.[121] By failing to account for this, EPA has substantially underestimated the cost to comply with the Proposed Rules.

1. Carbon capture and storage

The proposed standards for the CCS pathway are not cost effective. EPA's cost analysis for CO_2 capture contains significant flaws and inconsistencies. A thorough discussion of these issues is contained in the *Analysis of Post Combustion CO_2 Capture, Transport, and Storage Costs in EPA's Proposed Power Plant Greenhouse Gas Emissions Rule* document accompanying these comments.[122]

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[116] Morris and Weeda Natural Gas at 4-8.
[117] Environmental Protection Agency. *Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document*. May 23, 2023. p. 9. (EPA Steam Unit TSD) Available at: https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0061.
[118] Morris and Weeda Natural Gas at 8.
[119] *Sierra Club*, 657 F.2d at 330.
[120] *Id.* at 325.
[121] Environmental Protection Agency. *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. p. 5-1. (RIA) Available at: https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.
[122] *See* Morris and Weeda CCS in its entirety.

EPA uses the most optimistic cost assumptions that do not reflect reality. As an example, EPA cites a $50 per metric ton cost for CCS.[123] This figure is from a study that assumes a 90% capacity factor for a unit operating CCS.[124] CCS costs drop significantly as capacity factor increases. But a 90% capacity factor is not realistic, and not consistent with real world examples. As the analysis referenced above explains, EIA data indicates in 2022 the average coal unit capacity factor was 47.8%. The Agency's assumption is inconsistent with EPA's own modeling, which includes ranges of between 40% and 70%.[125] A similar example is EPA's assumption of an impossible 100% availability of the CO_2 capture unit, which also helps drive down the projected per ton cost of CO_2 captured.[126] In reality, CCS equipment has run into significant reliability issues. For example, the CCS equipment at Boundary Dam 3 was only available 64.5% of the time from the first quarter of 2021 through the first quarter of 2023.[127]

Among the issues with EPA's estimate is a misrepresentation of the Section 45Q tax credit of $85 per ton of CO_2 captured and stored. EPA assumes that the tax credit is immediately applicable and cuts a flat $85 off the cost of captured and stored CO_2. This misrepresents how the tax credit works in practice. EPA wrongly assumes that every project can meet the requirements to qualify. This is not the case as there are a variety of apprenticeship, prevailing wage, and domestic content requirements that must be met. In some instances, these may not be possible, such as if domestic supply of needed materials fails to keep up with the increased demand resulting from the Proposed Rules. Further, the tax credit is only available for 12 years while the life cycle of any unit built or retrofit with CCS to obtain the credit would be considerably longer. For cooperatives, this poses the risk of having the unit become a stranded asset once the credit expires.[128] EPA additionally fails to consider the costs associated with the tax credit's reporting requirements.

Those are just the most glaring flaws on the CO_2 capture side of the CCS equation. EPA's assumptions about the costs of CO_2 transportation and storage are similarly problematic. EPA uses natural gas pipeline costs as a proxy for CO_2 pipeline costs, even though the latter operate at higher pressure and need to be made with a higher strength, higher cost steel.[129] Even assuming natural gas pipelines are a good proxy, EPA's estimated cost is lower than the industry's experience.[130] EPA's range is $1.2 million to $7.2 million per mile. Industry experience shows a range of $2 million per mile to as much as $13 million.[131] This discrepancy has significant implications for EPA's estimated pipeline costs.

For CCS system-wide costs, EPA relies on NETL studies based on NETL's *Quality Guidelines for Energy System Studies*.[132] While these guidelines work well for comparing project costs to each other, they have significant limitations for estimating total project costs due to a range of contingencies that can affect projects and necessary costs that are not included in those studies' scopes. The costs unaccounted for in the NETL guidelines include demolition or relocation of existing structures, measures to deal with extreme temperatures, and offsite storage. A full discussion of the limitations of NETL's guidelines for the purpose to which EPA uses them is available in the accompanying *Analysis of National Energy Technology Laboratory*

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[123] 88 Fed. Reg. 33,299.
[124] Global CCS Institute. *Technology Readiness and Costs of CCS*. Available at https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf.
[125] EPA Steam Unit TSD at 39.
[126] Morris and Weeda CCS at 4.
[127] Cichanowicz and Hein at 8-9.
[128] Morris and Weeda CCS at 7.
[129] Carbon Storage Appendix at 19.
[130] *Id.*
[131] *Id.*
[132] National Energy Technology Laboratory. *NETL Quality Guidelines for Energy System Studies*. February 2021. Available at: https://www.netl.doe.gov/projects/files/QGESSCostEstMethodforNETLAssessmentsofPowerPlantPerformance_022621.pdf.

Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy. As that assessment explains, a more complete estimate of project costs for CO_2 capture systems is available from EIA.[133] This estimate contains a fuller scope of project costs and is 68% higher ($5,876/kW versus $3,482/kW) than NETL's estimate.[134]

2. Clean hydrogen

The clean hydrogen pathway is also not cost effective. To begin with, EPA has identified a fuel that requires four times more energy to produce than it yields[135] as a "best" option in the Proposed Rules. But as with CCS, EPA has made inaccurate assumptions about the associated costs of co-firing clean hydrogen – including using NETL's guidelines discussed above to serve as a complete estimate, which is not the intention of the guidelines.[136]

EPA wrongly anticipates that units burning clean hydrogen will be able to operate at the same capacity as units do when burning natural gas.[137] Hydrogen has a lower energy density than natural gas despite its higher heating value.[138] This difference in energy density means that for a combustion turbine to achieve the same capacity burning hydrogen as it would with natural gas, it would need to use significantly more hydrogen.[139] According to the attached *Technical Comments on Hydrogen and Ammonia Firing*, when a unit is burning 96% percent hydrogen, as the Proposed Rules would require in 2038, it can only produce about 65% of the energy output that it could if using natural gas.[140] EPA acknowledges hydrogen's lower energy density, yet dismisses that impact on capacity for reasons that are not clear.[141]

EPA also erroneously assumes that there will be no need for a dedicated hydrogen pipeline network. As discussed earlier, EPA incorrectly assumes existing natural gas pipelines can be utilized.[142] The dedicated pipeline network needed for clean hydrogen would have to use more specialized equipment throughout, including compressors that operate at three times the speed of natural gas compressors.[143] This means that existing pipelines cannot be repurposed to accommodate pure clean hydrogen. The Agency has also not adequately accounted for natural gas unit operational challenges associated with the transition to co-firing clean hydrogen. This includes the likelihood of increased maintenance and equipment replacement costs associated with hydrogen's higher flame temperature.[144]

3. Natural gas co-firing at existing coal units

EPA has not shown natural gas co-firing to be cost effective either, as it has not completely assessed the cost for existing coal-fired EGUs without a current supply of natural gas to access it.[145] As discussed earlier, EPA

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[133] U.S. Energy Information Administration (via Sargent & Lundy). *Capital Cost and Performance Characteristics for Utility Scale Electric Generating Units.*
[134] Campbell NETL at 9.
[135] Campbell Hydrogen at 3.
[136] *Id.* at 2-3.
[137] Environmental Protection Agency. *Resource Adequacy Analysis Technical Support Document.* May 23, 2023. p. 8. (Resource Adequacy Analysis TSD) Available at: https://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf.
[138] Kiewit at 9-10.
[139] *Id.*
[140] *Id.* at 10.
[141] *Id.* at 9-10.
[142] *Id.* at 19-21.
[143] Campbell Hydrogen at 6.
[144] Kiewit at 13-15.
[145] Morris and Weeda Natural Gas at 4-8.

has failed to consider the additional costs that will be incurred from likely delays associated with permitting and public opposition to pipelines.[146] EPA also underestimates the engineering challenges associated with co-firing conversions, which can add significant costs to projects.[147] Combined, these costs will be substantial and will prove to be uneconomical for units given the investment will only be amortized over 10 years before retrofitted units shut down by 2040.

For example, Arkansas Electric Cooperative Corporation estimates that to continue operating one of their coal-fired units until 2040, less than its remaining life, they would need to invest $70 million to $120 million by 2030 just to bring natural gas to the plant site in order to co-fire with natural gas. Necessary retrofits to the plant to enable co-firing would require additional investment.[148] In the case of AEPCO in Arizona, steam unit 2 of the Apache Generating Station has been converted to natural gas, but additional firm natural gas transportation is not available on the natural gas supply pipeline. If coal-fired steam unit 3, which is the same size as steam unit 2, were converted to natural gas, the current metering station, piping, and transportation contracts would require modifications to reliably deliver additional gas to the site. To convert unit 3, AEPCO would more than likely have to purchase spot delivered market natural gas exposing them to market volatility in fuel pricing.[149]

4. Reliability

In addition, the Proposed Rules are not cost effective and fail to account for "energy requirements" due to the negative impacts on reliability expected from their implementation and the errors associated with EPA's Integrated Planning Model (IPM) model. As detailed in Section VIII, the Proposed Rules will necessarily degrade reliability – and EPA, by its own definitional distinction, has only examined resource adequacy. Should EPA adopt the Proposed Rules as published, affected operators would be forced to expend limited resources on unproven and costly technologies. This is an especially pressing concern for electric cooperatives, which – by necessity – will have to pass increased costs directly to consumer-members.

As discussed in Section VIII.B of these comments, EPA's IPM Updated Baseline contains 66 retirements erroneously attributed to the IRA (as opposed to the Proposed Rules) identified in 2028 and 2030. By linking those retirements to the IRA, EPA substantially underestimates the Proposed Rules' direct impact on the retirement of the generation necessary to ensure reliability.[150]

EPA also underestimates the parasitic load associated with CCS, or the electricity consumed to power the capture unit and related equipment that is not available for grid use. EPA assumes an 18% parasitic load,[151] but a 25% to 30% assumption is more appropriate.[152] This difference has meaningful implications as it would reduce net power output by up to an additional 12% percent across the fleet, further straining reliability.

5. Building of more, smaller units

Another flaw in EPA's evaluation of nonair quality, environmental, and energy requirements is its failure to grapple with the significant inefficiencies that the proposal will cause. As demonstrated in the attached *Technical Comments on Hydrogen and Ammonia Firing*, EPA's combustion turbine requirements are likely

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[146] Cichanowicz and Hein at 23-29.
[147] Morris and Weeda Natural Gas at 8.
[148] *Id.* at 8.
[149] *Id.* at 9.
[150] Marchetti Comments at 19.
[151] Resource Adequacy Analysis TSD at 9.
[152] Weeda at 4; Walsh at 4.

to lead to the construction of multiple combustion turbines that operate at less than 50% capacity.[153] EPA's own flawed IPM model shows the industry building more than 50% more small combustion turbines than the base case.[154] This is highly inefficient from an environmental, energy, and economic perspective. Building larger, more efficient units is generally less costly, more efficient, and results in less externalities than building multiple smaller units. EPA's decision to create standards based on undemonstrated, unachievable emissions standards makes the construction of more, smaller units inevitable.

D. The proposed emissions standards cannot be applied to emissions sources.

The Proposed Rules are also unlawful because they would require the construction and procurement of equipment "outside the fence" of sources. Performance standards under Section 111 apply to "sources, " not owners and operators or society as a whole.[155] "Source" is specifically defined as an individual physical "building, structure, facility, or installation."[156] Indeed, until the unlawful Clean Power Plan was struck down by the Supreme Court, EPA consistently interpreted Section 111 to refer "*exclusively* to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as [the best system of emissions reduction.]"[157] But the proposed standards require actions that are not measures that improve the pollution performance of individual sources. As described above, they would require the unprecedented construction of entirely new CO_2 and hydrogen pipeline networks. They would require the creation of entire new industries to handle and sequester CO_2 and to manufacture and transport clean hydrogen. Those pipeline networks and new industries are not measures that can be applied to individual sources and therefore exceed EPA's authority.[158]

For similar reasons, EPA's alternative requirement that sources limit operation or declare retirement exceeds EPA's authority. Neither of those options are measures that can be applied to a source to improve its performance. It is the curtailment of their performance altogether in favor of other forms of generation that EPA prefers. That is exactly the kind of "generation shifting" that the Supreme Court held exceeded EPA authority under Section 111.

V. EPA's Proposed Compliance Timeline is Unrealistic.

As NRECA has demonstrated in these comments and the associated attachments, EPA's determination that CCS, clean hydrogen, and natural-gas co-firing are best systems of emission reduction fails to meet the CAA's requirements. Even if these standards were viable, however, the Agency's compliance timeline is unrealistic, and would be unworkable on any timeline contemplated by EPA.

The Proposed Rules' requirements for existing coal-fired EGUs would have to be met by January 1, 2030. Assuming the proposed emission guidelines are adopted on the timeline laid out in the most recent Unified Agenda of Regulatory and Deregulatory Actions,[159] state plans would not be approved by EPA (or go into effect) until April of 2027 at the earliest. Only at that point can existing units have the regulatory certainty to proceed with compliance efforts. Those EGUs operating beyond 2039 (long-term units) and 2034 (medium-term units) would not have the time to implement the required technologies, CCS and natural-gas co-firing

[153] Kiewit at 5.
[154] *Id.*
[155] *E.g.* 42 U.S.C. § 7411(a), (d), (b).
[156] *Id.* § 7411(a)(3).
[157] *West Virginia*, 142 U.S. at 2596.
[158] *Id.* at 2611-12.
[159] Office of Information and Regulatory Affairs. *Spring 2023 Unified Agenda of Regulatory and Deregulatory Actions*. June 13, 2023. Available at: https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2060-AV09.

respectively, in less than three years. In fact, even if those units began those efforts *today,* they would be very unlikely to be in compliance by the beginning of 2030. However, EPA cannot expect EGUs to take action toward compliance until EPA signs off on state plans to implement the standards.

EPA proposes a timeline of five years to deploy CCS and related infrastructure and equipment.[160] But this timeline is anything but reasonable. For purposes of installing CO_2 capture equipment on an EGU, EPA wrongly assumes that procurement of the equipment occurs prior to permits being issued. In most cases, units will need to secure financing in order to obtain equipment, and financing is unlikely to be secured until all permits are in place.[161] The Agency also fails to recognize that much of the best geologic storage is located under federal lands (therefore requiring NEPA review which averages more than four years) and that many state governments have not settled how they will deal with pore space ownership.[162]

EPA's timeline is based on an arbitrarily "expedited" version of a longer timeline developed by Sargent & Lundy and cited by the Agency. The longer Sargent & Lundy schedule shows a timeline of six to seven years.[163] Yet even this longer timeline "does not include the scope associated with the development of CO_2 off-take/storage (including transportation, sequestration, enhanced oil recovery utilization, and/or utilization)."[164]

Neither of the timeframes discussed above comport with real world CCS capture system deployment, based on summaries of DOE-funded front-end engineering and design schedules.[165] These studies are consistent with discussions NRECA has had with several engineering, procurement, and construction firms in the CCS industry under ideal circumstances.[166] There are unknown hurdles regarding timing that will only be identified as the technology matures. So, while history may be a more realistic guide than EPA's timeline for a single project in a suitable location, it is still not a realistic timeframe for the full development and deployment of dozens of systems across the country that would be required – particularly given the necessary outside the fence line infrastructure.

Similar problems arise with the proposed guidelines for medium-term coal-fired EGUs. Most of these EGUs do not have access to natural gas, which means that a pipeline would need to be constructed.[167] As just discussed with regard to CCS, building a pipeline requires lengthy timelines, assuming projects are eventually completed. Even coal-fired EGUs that do have access to natural gas may not be able to obtain the quantities of natural gas needed to co-fire at this level on a reliable basis as recent weather events have demonstrated (or even at all depending on the pipeline and infrastructure).[168]

Affected natural gas units will fare no better under the EPA's compliance timeframe. The challenges presented for those considering CCS are similar to those mentioned above for coal units, though there are zero such units operating CCS currently. That essentially leaves the clean hydrogen pathway as the only option. But even assuming that clean hydrogen was adequately demonstrated, compliance could not be achieved by the phase 2 requirement of January 1, 2032.

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[160] EPA Steam Unit TSD at 36.
[161] EERC at 11.
[162] *Id.* at 11.
[163] *Id.* at 12.
[164] Sargent & Lundy. *CCS Schedule (Coal Boilers or NGCC).* 2023. (Available in the rulemaking docket as an attachment to the EPA Steam Unit TSD).
[165] Cichanowicz and Hein at 30-39.
[166] Walsh at 4.
[167] Morris and Weeda Natural Gas at 4-8.
[168] *Id.* at 4.

As discussed in Section IV, the timeframe for clean hydrogen to be produced at scale in time for operators to comply with EPA's requirement is unsupported due to its failure to address the fact that hydrogen takes more electricity to produce than it yields, the cost of production, and the water volumes necessary.[169] It is also not realistic to design, procure, permit, and construct the vast pipeline network needed for compliance, essentially from scratch, in less than nine years.[170]

These unrealistic timelines mean that the practical effect of the Proposed Rules is that coal units will be forced to pursue the compliance pathways associated with imminent or near-term units and retire prematurely. Existing natural gas units will be forced to opt to lower their capacity factors to 20% or below and become low load units. Further, EPA's decision to choose a capacity factor of 20% as the threshold for low load units is arbitrary, since trends indicate that simple cycle combustion turbines – those often used as "peaking" units – continue to run at increasing capacity factors, and in the summer of 2022 the average capacity factor of simple cycle units surpassed 20%.[171] This combination of premature retirements from coal units and (arbitrarily) low capacity factors from natural gas units will exacerbate the reliability issues discussed later.

VI. EPA's Proposed Applicability Dates are Incorrect as a Matter of Law.

As the Proposed Rules correctly recognize, "the CAA defines an 'existing source' as 'any stationary source other than a new source,'" and that the proposed emission guidelines for existing sources "would not apply to any EGUs that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT."[172]

Yet, on June 12, 2023, EPA issued a "Memo to the Docket" entitled *Applicability of Emission Guidelines to the Existing Stationary Combustion Turbines: FAQs*.[173] In this memo, EPA unlawfully states that the above applicability interpretation only applies to coal units. It goes on to say that "stationary combustion turbines that commenced construction or reconstruction before May 23, 2023, are existing sources that may be affected EGUs" under the proposed emission guidelines for existing units.[174]

Section 111(a)(6) of the CAA defines an "existing source" as "any stationary source other than a new source."[175] A "new source," in turn, is "*any* stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing *a* standard of performance under this section which will be applicable to such source."[176] This statutory text is clear and unambiguous. A source cannot be both "new" and "existing." Stationary combustion turbines constructed after January 8, 2014, are "new" sources that complied with Subpart TTTT. These units cannot be both "existing" and "new" under the CAA. Combustion turbines constructed after January 8, 2014, whose CO_2 emissions were subject to Subpart TTTT are "new sources" under Section 111, cannot be existing sources because those sources are already subject to "*a* standard of performance" for CO_2 under Section 111.

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169 Campbell at 3.
170 Kiewit at 19-21.
171 Energy Information Administration. *U.S. simple-cycle natural gas turbines operated at record highs in summer 2022*. March 1, 2023. Available at: https://www.eia.gov/todayinenergy/detail.php?id=55680.
172 88 Fed. Reg. 33,342.
173 Environmental Protection Agency. *Applicability of Emission Guidelines to the Existing Stationary Combustion Turbines: FAQs*. June 12, 2023. Available at: https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0143.
174 *Id.* at 2.
175 42 U.S.C. § 7411(a)(6).
176 42 U.S.C. § 7411(a)(1) (emphasis added).

Further, it is arbitrary and capricious for EPA to say (correctly) that steam generating units that complied with Subpart TTTT are "new" sources (and thus not subject to the proposed emission guidelines) while stationary combustion turbines that complied with that same provision are "existing" sources that are subject to the proposed emission guidelines. EPA needs to make clear that any EGU – whether a steam generating unit or a stationary combustion turbine – that commenced construction prior to January 14, 2014 (or that commenced a reconstruction or modification after June 18, 2014) and was subject to Subpart TTTT is *not* an existing source for the purposes of the proposed emission guidelines.

VII. The Proposed Rules Illegally Restrict States' Discretion to Evaluate the 'Remaining Useful Life and Other Factors.'

The CAA requires that EPA's implementing regulations under Section 111(d) shall "permit the State in applying a standard of performance to any particular source under a plan submitted [under Section 111(d)] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[177] EPA therefore cannot deny a state discretion to take remaining useful life into consideration and cannot restrict that consideration in the Proposed Rules.

Despite this clear statutory language, the Proposed Rules unlawfully impose restrictions on state consideration of remaining useful life and other factors that will effectively prevent them from exercising the discretion guaranteed by Section 111(d)(1). First, EPA's proposal to exclude sources that have been given less stringent emission limitations because of their remaining useful life from any potential state emissions allowance trading program is arbitrary and capricious. Those sources can easily be included in trading programs—the budget for that source could simply be derived by considering its emissions limitation, as adjusted for its useful life remaining. Second, EPA has suggested that a state may not consider "impacts on the energy sector" while making remaining useful life determinations because EPA already considered those impacts while analyzing the best system of emission reduction.[178] But the CAA requires states to consider local "energy requirements" when setting standards of performance for existing sources.[179] Congress specifically recognized that states, not EPA, have the expertise and authority to evaluate their own energy requirements. States may have energy-related reasons (such as grid reliability) for keeping an older plant open, even if it is used infrequently, that necessitates developing a source specific emissions standard based on the plant's remaining useful life.

Additionally, the Proposed Rules could be read as asserting that states may not consider remaining useful life and other factors when using flexible compliance mechanisms to satisfy EPA's required level of stringency. Those flexible compliance mechanisms might allow particular sources to emit at higher levels by obtaining allowances while still resulting in the state as a whole satisfying EPA's presumptive level of emissions stringency.[180] EPA cannot foreclose such flexibility. Instead, it should clarify that if a state plan meets the required level of emissions reductions in a way that permits certain plants to exceed their emissions limitations, the plan will still be approved as "satisfactory."[181]

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[177] 42 U.S.C. § 7411(d)(1).
[178] 88 Fed. Reg. 33,382 n.628.
[179] 42 U.S.C. § 7411(a)(1).
[180] *See* 88 Fed. Reg. 33,383 (Noting "a State may not invoke RULOF 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").
[181] *See* 87 Fed. Reg. 79,176, 79,198 (Suggesting that a state need not rely on the remaining useful life and other factors analysis when demonstrating that a group of facilities "would, in the aggregate, achieve equivalent or better reductions than if the state instead imposed the presumptive standards required under the [emission guideline] at individual designated facilities.").

VIII. The Proposed Rules Will Exacerbate Existing Challenges to Reliability.

The Proposed Rules, and their reliance on promising but unproven technologies on an unachievable timeline, will directly jeopardize the ability of electric cooperatives to provide affordable, reliable electricity to their consumer-members. As discussed in Section II.B, providing affordable, reliable, and safe electricity is paramount for electric cooperatives. It is incumbent upon EPA to consider the reliability impacts of their regulatory actions and mitigate them to the fullest extent possible. Unfortunately, EPA has not come close to doing either in contemplating its Proposed Rules. EPA has failed to adequately assess the Proposed Rules' impacts on reliability, relied upon deficient modelling that understates the proposal's impact on always available generation, and inconsistently applied the IRA in projecting changes in electric sector.

A. EPA fails to adequately assess the Proposed Rules' impacts on reliable electricity.

1. EPA did not analyze the Proposed Rules' impacts on reliability.

The preamble to the Proposed Rules acknowledges the critical need for reliability.[182] However, there is no reliability analysis accompanying the Proposed Rules. Instead, the Proposed Rules rely upon "design elements," EPA's intention to exercise its enforcement discretion, and a resource adequacy analysis. The deficiency in the design elements is discussed in Sections IV and V above and the ineffectiveness of the proposed enforcement discretion is discussed in Section VIII.A.3 below.

At the outset, the Proposed Rules are deficient by failing to specifically analyze and address reliability. The Proposed Rules provide a resource adequacy analysis to presumably demonstrate that the Proposed Rules will not adversely impact reliability, yet resource adequacy is different from reliability. As EPA itself explains, "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."[183] The Grid *Reliability* Considerations in the preamble to the Proposed Rules explain that "[t]o support these proposed actions, the EPA has conducted an analysis of *resource adequacy*…" set forth in the Resource Adequacy Analysis Technical Support Document (TSD).[184] The TSD does not analyze reliability.

The Resource Adequacy TSD states that it "describes projected resource adequacy and reliability impacts of the Proposed Rules."[185] Yet as previously stated, the TSD defines "resource adequacy" and "reliability" differently, and states that the 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 IRA."[186] Moreover, reliance on the IRA to jumpstart the clean hydrogen and CCS infrastructures that are critical to any EGU retrofits in order to comply with the Proposed Rules is overly optimistic, cannot be factually supported, and therefore is flawed and cannot be relied upon when reliability of the grid is at stake. EPA's analysis fails under the weight of its own assumptions that current technologies can be scaled up in the future to the magnitude of current operations, infrastructure can be permitted and

[182] 88 Fed. Reg. 33,246-33,247.
[183] Resource Adequacy Analysis TSD at 2.
[184] 88 Fed. Reg. 33,415 (emphasis added); *see also,* RIA at 3-25, 3-26, n. 90 (After stating projected coal retirements as a result of the Proposed Rules, the RIA states that "[t]hese compliance decisions reflect EGU operators making least-cost decisions on how to achieve efficient compliance with the rules while maintaining sufficient generating capacity to ensure grid reliability . . .For further discussion on how the rule is anticipated to integrate into the ongoing power sector transition while not impacting *resource adequacy*, see section XIV(F) of the preamble, and the Resource Adequacy Analysis TSD included in the docket." (emphasis added)).
[185] Resource Adequacy Analysis TSD at 2.
[186] *Id.*

constructed more rapidly than ever before in the past, technology and infrastructure will be paid for without question, and that the process will unfold smoothly according to the unrealistic timeline EPA has developed.

Rather than undertake a reliability analysis, EPA points to studies that purportedly demonstrate "how reliability continues to be maintained under high variable renewable penetration scenarios."[187] Even assuming these third party studies are correct, which may or may not be the case, the ability to maintain reliability with an influx of new intermittent 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, as a result of implementation of the Proposed Rules. Accordingly, the Proposed Rules fail to provide an analysis of reliability impacts.

2. Forcing baseload resources to make retirement decisions further threatens electric reliability.

EPA contemplates that some EGUs will be retired as a result of the Proposed Rules.[188] The IPM Updated Baseline projects total coal retirements between 2023 and 2035 of 104 GW (or 15 GW annually), while total coal retirements under the Proposed Rules between 2023 and 2035 are projected to be 126 GW (or 18 GW annually), as compared to an average historical retirement rate of 11 GW per year from 2015-2020.[189] As discussed in Section VIII.B, EPA erroneously attributes these retirements to the IRA instead of the Proposed Rules. These retirements will impact electric cooperatives' ability to reliably serve consumer-members at the end of the line. For example, as Buckeye Power Inc. described in June 6, 2023 congressional testimony, the Proposed Rules will cause a costly shutdown of all of Buckeye Power's coal-fired units by 2030 with no ability to replace the energy in that timeframe.[190] Buckeye CEO Patrick O'Loughlin framed the reliability challenge facing his cooperative this way: "[a]s someone who has worked in the electric power industry for decades, I know that despite what EPA has claimed, this rule will in fact have a serious negative impact on the reliability of our electric system and will result in a dramatic increase in costs to Ohio's electric cooperative members. It is imperative that EPA change course."

Further, the ability of existing generators to comply with the Proposed Rules will depend in significant part on the ability to schedule outages for EGUs in order to install controls. However, RTOs and independent system operators (ISOs) are already warning that the ability to take maintenance outages is limited in many regions. As the Midcontinent Independent System Operator (MISO) recently warned with respect to EPA's proposal to deny applications by certain generation plans for an alternate linear demonstration regarding coal combustion residuals surface impoundments:

> MISO faces increasing challenges to system reliability and the ability to commit sufficient resources to supply electricity customers within the Midcontinent region. Even with the growth of alternative and renewable energy sources, MISO continues to be concerned about the looming shortfall of generation needed to ensure grid reliability in the region. Within the MISO region, the retirement of generation plants is occurring faster than new energy sources with

[187] *Id.*
[188] 88 Fed. Reg. 33,416.
[189] *Integrated Proposal Modeling and Updated Baseline Analysis*. July 7, 2023. p. 16. Available at: https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0237.
[190] Testimony of Patrick O'Loughlin, President and CEO of Buckeye Power Inc. and Ohio Rural Electric Cooperatives, House Energy and Commerce Subcommittee on Environment, Manufacturing and Critical Materials. June 6, 2023, at 3. Available at: https://energycommerce.house.gov/events/environment-manufacturing-and-critical-materials-subcommittee-hearing-clean-power-plan-2-0-epa-s-latest-attack-on-america-s-electric-reliability.

equivalent attributes, whatever the fuel source, can be developed, constructed and brought online.[191]

MISO further explained that "retirement/suspension requests as well as planned outages will require particular attention to ensure continued grid reliability and resource adequacy."[192]

As discussed in Sections IV and V of these comments, compliance under the Proposed Rules is infeasible on any timeframe EPA is considering. Indeed, EPA's proposals are among several fundamental changes to the energy industry in the federal regulatory pipeline. There are several policies from EPA alone, either proposed or recently implemented, that will compound the detrimental effect of the Proposed Rules on reliability. As discussed in Section II, the steam electric effluent limitations guidelines rule, the coal combustion residuals rule, and the ozone transport rule, have the potential to accelerate and increase the 40 GW of retirements contemplated by PJM.[193] Moreover, the Federal Energy Regulatory Commission (FERC) recently finalized comprehensive reforms to its procedures for interconnecting generation to the grid[194] and is also addressing transformative changes to transmission planning and cost allocation.[195]

As one RTO has explained, "[m]aintaining an adequate level of generation resources, with the right operational and physical characteristics, is essential for PJM's ability to serve electrical demand through the energy transition."[196] The Proposed Rules will only increase and exacerbate these threats to reliability.

3. EPA's approach is insufficient to address or mitigate the adverse impacts on reliability that will result from the Proposed Rules.

The measures in the Proposed Rules do not enable responsible authorities to maintain electric reliability. As discussed in Section IV and V, the compliance requirements are based on a deficient, unreasonable, and arbitrary analysis. Moreover, measures identified in the Proposed Rules to purportedly preserve electric reliability are insufficient to mitigate adverse impacts to reliability. The Resource Adequacy Analysis TSD acknowledges that some EGU owners may determine that retiring and replacing an asset is a more economic option than making substantial investments in emissions controls in order to comply with the Proposed Rules.[197] But, there is no guarantee that a resource retirement would be accompanied by a similarly adequate replacement from a reliability perspective. In fact, given transmission queue delays, permitting delays, and unprecedented electric supply chain disruptions and lead times, it is highly unlikely.[198]

Furthermore, EPA unreasonably relies on the retirement process in place by the relevant RTO, balancing authority, or state regulator to protect electric system reliability. The EPA contends that its Proposed Rules provide the flexibility needed to avoid reliability concerns.[199] However, EPA's expectation that these entities

[191] Comments from Midcontinent Independent System Operator, Inc. Regarding the United States Environmental Protection Agency's Request for Comments re Docket ID Nos. EPA-HQ-OLEM-2021-0283, EPA0HQ-OLEM-2021-0282, EPA-HQ-OLEM-2021-0280, dated April 10, 2023 at 4-5.
[192] *Id.*
[193] Energy Transition in PJM at 7.
[194] RM22-14-000; Order No. 2023 Improvements to Generator Interconnection Procedures and Agreements, 184FERC ¶ 61,054 (Issued July 28, 2023).
[195] RM21-17-000, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Advanced Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (2021), 86 Fed. Reg. 40,266; RM21-17-000, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022), 86 Fed. Reg. 26,504.
[196] Energy Transition in PJM at 1.
[197] Resource Adequacy Analysis TSD at 3.
[198] Marchetti Comments at 11-16.
[199] 88 Fed. Reg. 33,415.

will "use their powers to ensure that electric system reliability is protected" is far from sufficient to address, let alone analyze, the adverse impacts on reliability that will result from generators who opt for retirement as the only feasible option. Significantly, in such instances, EGU owners have the right to retire their facilities subject to notice provisions. Because RTOs have no authority to order EGUs to continue operating rather than retire,[200] existing retirement processes simply cannot provide assurance against reliability impacts as EGUs retire in response to the Proposed Rules.

EPA's intention to exercise its enforcement discretion to address instances where individual EGUs might need to temporarily operate for reliability reasons is also insufficient protection against adverse reliability impacts from the Proposed Rules.[201] As a general premise, EPA's assertion that it may exercise enforcement discretion in some unforetold circumstances is cold comfort. Discretionary action by the Agency holds no guarantees and provides stakeholders little avenue for review. Among other reasons, the exercise of enforcement discretion necessarily involves political and policy judgments that are subject to change based on the results of elections and who holds the decision-making authority. To provide any reasonable relief from reliability concerns, EPA would need to promulgate regulations setting forth the rights and obligations of stakeholders and allow for swift judicial review of the Agency's decisions.

In the instant situation, EPA's explanation demonstrates that the outcome of exercising discretion in enforcement is uncertain and may be so time-consuming as to render it useless in many instances as a stop-gap measure to protect against adverse reliability impacts of the Proposed Rules. The Proposed Rules describe a case-by-case process in which an affected EGU that is required to run in violation of a state plan requirement can negotiate an administrative compliance order (ACO) with EPA.[202] The Proposed Rules include a set of minimum conditions to qualify for an ACO. The conditions will make it challenging, at best, for EGUs to obtain an ACO in instances of urgent reliability needs.

Among other things, the ACO would be conditioned on the owner/operator of the affected EGU requesting, "in writing and in a timely manner" (1) an enforceable compliance schedule in an ACO; (2) a written analysis and documentation of reliability risk if the unit were not in operation that would include a compliance schedule, with written concurrence of the reliability analysis from the relevant electric planning authority; (3) a demonstration that the need to operate for reliability is due to factors beyond the EGU owner/operator's control; (4) a demonstration that all increments and milestones in the state plan have been met; and (5) a demonstration that there is insufficient time to address the reliability risk and potential noncompliance through a revision to the state plan.[203] If EPA deems it appropriate to do so, it would then issue an ACO that would include an expeditious compliance schedule and operational limits.[204] But there are no guarantees that EPA would even act on such a request in a timely manner, especially since the Agency has given itself no deadline and presumably would argue any decision not to exercise its enforcement discretion is not subject to judicial review.

EPA's ACO proposal is particularly unworkable for purposes of addressing more immediate reliability needs. For example, for EGUs in an RTO/ISO region, the notification that units are needed for urgent reliability needs, or even short-term reliability needs, may not be provided sufficiently in advance for the EGU owner to prepare all of the documentation required by EPA.[205] Moreover, the requirement to provide a written analysis and documentation of the reliability risk if the unit were not in operation is in most instances

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[200] Energy Transition in PJM at 6.
[201] 88 Fed. Reg. 33,415.
[202] 88 Fed. Reg. 33,401.
[203] 88 Fed. Reg. 33,401-33,402.
[204] 88 Fed. Reg. 33,402.
[205] All regional planning authorities would face such challenges.

information that the EGU owner would not possess but instead would require information and analysis from the regional entity or state. The EGU owner may not be able to obtain an analysis from the regional entity or the state that meets EPA's specifications, and particularly not in a timely manner, as there may be requirements to request the analysis. The same is true of the requirement to demonstrate that there is insufficient time to address the reliability risk and potential noncompliance through a state plan revision.

Finally, on this issue, the case-by-case approach proposed by EPA, with a possibility of additional conditions beyond those stated, leaves EGUs with little to no assurance that they will be permitted to continue operating for reliability at a time when such continued operation is critical. EGU owners would face a "Hobson's choice" between the consequences of noncompliance with the state plan or the consequences of not being available for reliability, and the electric grid might be deprived of a resource when it is most needed for reliability. If EPA expects the ACO process to in fact assist in maintaining reliability of the grid, EPA should defer to comments from the RTOs and other regional entities.

4. **Even assuming that the Proposed Rules are lawful, it would be necessary to improve measures protecting against the adverse reliability impacts.**

The discussion regarding EPA's coordination with DOE under the Memorandum of Understanding (MOU) on Interagency Communication and Consultation on Electric Reliability is insufficient to address the risks to reliability posed by the Proposed Rules.[206] Coordination between EPA and FERC, the agency charged with ensuring reliability, is important. However, the MOU and Proposed Rules do not guarantee that there will be any meaningful steps to ensure that EPA's Proposed Rules take reliability into account and that the Agency will adopt mitigation measures that protect against adverse impacts on reliability. If EPA is serious about addressing the adverse impacts on reliability, it should put the Proposed Rules on hold and implement the MOU with DOE by conducting a series of technical conferences with FERC, NERC, states, regional entities and other stakeholders.[207] The following suggestions would be ripe for discussion at technical conferences.

First, as currently drafted, the ACO proposal is unworkable. As detailed in Section VIII.A.3, in order for the ACO process to function, it must provide EGUs with reasonable opportunities to obtain the requisite documentation from the applicable regional entity or the state, as appropriate. This is particularly important in the case of a threat to immediate reliability needs. In that instance, as opposed to requiring the EGU owner to demonstrate the need for its EGU to run for reliability and the implications if it does not do so, EPA should provide that the condition can be met if the RTO or other relevant electric entity has declared a reliability issue (such as a System Emergency).

Second, the definition of System Emergency should be revised to include all instances where EGUs are required to operate by the local grid operator for circumstances beyond the EGU owner's control.[208] The current definition in the Proposed Rules is restricted to instances where the local grid operator determines the EGU is essential to maintain reliability.[209] Additionally, in the event that an EGU operating pursuant to a System Emergency under the Proposed Rules exceeds its annual emissions limitations under other applicable EPA regulations, EPA should clarify the EGU shall not be deemed in violation and subject to penalties or changes to its subcategorization under such other requirements.

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[206] *Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability*. March 9, 2023. Available at: https://www.epa.gov/power-sector/electric-reliability-mou.

[207] Public interagency discussions were part of the Clean Power Plan process and should be required for the rule. Indeed, Congressional requests for exactly this type of public forum have already been addressed to FERC. *See* Letter from Senators Barrasso and Capito to FERC Chair Phillips and Commissioners Danly, Clements, and Christie. June 30, 2023.

[208] 88 Fed. Reg. 33,333.

[209] *Id.*

Third, the process for coordination with stakeholders, including federal and state agencies, should be more formal and publicized, with an opportunity for comments and requirements for periodic reports by EPA and/or FERC or other agencies, regarding maintaining reliability with implementation of the Proposed Rules.

Finally, any final rules in this docket should formalize a process with adequate opportunity and time for NERC to render a reliability assessment to be provided to EPA and other agencies as part of the coordination for implementation of the rule.

B. EPA's Integrated Planning Model understates the impacts of the Proposed Rules.

EPA uses its IPM to develop projections out to 2050 on future outcomes of the electric power sector. The modeling relies on input data and assumptions from the Post-IRA 2022 Reference Case.[210] Based on the output of EPA's model, the Agency determines that the IRA is responsible for much of the retirements in fossil fuel power generation over the foreseeable future. Accordingly, EPA projects the Proposed Rules to have only minor effects. This projection is incorrect.

An analysis performed for the Power Generators Air Coalition, of which NRECA is a part, examines how IPM modeled individual units' retirement decisions.[211] Due to time constraints, worsened by EPA's July 7 modeling update, the analysis only looks at how coal units were modeled for 2030 – when IPM predicts a significant drop in coal unit capacity. This analysis found that EPA's Updated Baseline used to measure the impacts of the Proposed Rules on electric generation assets is seriously flawed, mainly attributed to EPA's assumptions regarding IRA implementation. Most notably, IPM incorrectly projected the retirement of 66 coal units which represent 40% of the retired Updated Baseline coal capacity in 2030. This incorrect projection seriously compromises the baseline. IPM also projected the retrofit of units with CCS by 2030, which is impossible for the reasons explained in detail earlier in these comments and its accompanying attachments.

Table 1 summarizes the IPM retirement errors in the 2028 and 2030 modeling runs. Specifically, IPM incorrectly projected the retirement of 41 coal units (18.1 GW) by 2028 and an additional 25 coal units (15.9 GW) by 2030 in the Updated Baseline. No public statements or filings related to integrated resource plans for these 66 units have been made indicating they intend to retire, including statements and filings made subsequent to the passage of the IRA. This indicates that even though unit operators are aware of the IRA's financial incentives, neither the incentives themselves nor the lack of certainty about their implementation is likely to result in the retirements EPA projects. Again, these 66 retirement errors (34.0 GW), account for almost 40% of the modeled retirements in the Updated Baseline. This extremely high percentage of erroneous coal retirements is attributed to EPA's unreasonable assumptions of IRA implementation, which results in the Updated Baseline being significantly compromised.

Table 1

IPM Modeled Coal Retirement Errors in the Updated Base Case

Year	IPM Retirements	Retirement Errors
2028	108	41
2030	58	25
Total	166	66

[210] Environmental Protection Agency. *Documentation for Post-IRA 2022 Reference Case.* April 5, 2023. Available at: https://www.epa.gov/power-sector-modeling/documentation-post-ira-2022-reference-case.
[211] Marchetti Comments at 17-22.

The analysis, submitted in full along with these comments, also found errors with at least three units that, according to EPA's Updated Baseline case, were modeled to have installed CCS by 2030, but would be retired due to the Proposed Rules. Given the limited scope of the analysis, it is possible other aspects of the modeling – such as how natural gas units would be affected – contain errors. In any event, the significant errors in EPA's IPM model render any analysis based on that model arbitrary and capricious.

C. EPA inconsistently models impacts from the Inflation Reduction Act.

While EPA uses the IRA to minimize the direct economic impact of its regulations in rulemakings, including this one, where it has incorporated the IRA's effects in its modeling, the Agency's modeling does not adequately account for the load growth associated with increased electrification of the economy that is a goal of the IRA and the administration's policy efforts.

EPA's model relies on the electricity demand projections from the EIA's Annual Energy Outlook 2021. This edition was published in February 2021, 18 months before the IRA's passage. The IRA was designed to drive electrification faster than EIA assumed in February 2021 – by incentivizing a more rapid adoption of technologies like electric vehicles (EVs), heat pumps, and electrolysis for clean hydrogen production – yet the demand impacts associated with this acceleration are not reflected in EPA's modeling. Concurrently, the administration has proposed a number of regulatory efforts that will incentivize increased electrification, including tailpipe emissions and fuel economy standards for vehicles, efficiency standards for various home and commercial appliances, and even standards for federal buildings. Taken together with the IRA's incentives, these actions will result in significant increases in electricity demand.

In particular, it is important for EPA to recognize that electrification of the transportation sector, and the associated increased demand, will require substantial distribution infrastructure investment over time to meet increased average local electric demand and to meet increased demand in new locations (e.g., EV charging stations). Significant transmission infrastructure investment may also be required to meet increased average electric demand and changes in the spatial distribution of electric demand among load centers.[212]

As such electrification takes place, cooperatives must maintain always available generation to keep up with this increased demand in a way that ensures an adequate supply of affordable, reliable, and safe electricity. The result of these arbitrary decisions is that the Agency has failed to model the increase in load growth from the IRA's policies while at the same time using the IRA to increase expected retirements in the Updated Baseline, as described above. This fails to give a reasonable projection of the energy mix and strain on reliability. Further, the costs associated with electrification in EPA's analysis are grossly understated and undercut EPA's assertion that affordable electricity will be possible under these Proposed Rules.

IX. EPA's Environmental Justice Analysis is Lacking.

Although EPA claims that the impacts of its Proposed Rules will be distributed across demographic groups, it has overlooked key issues affecting environmental justice communities and has failed to substantively engage with stakeholders advocating on behalf of those communities.

First, EPA has not examined the full picture of how the Proposed Rules will impact electricity prices. Costs associated with emissions controls factor into overall power plant costs, which are then reflected downstream in electricity prices for consumers. This is particularly true of electric cooperatives, which must pass any

[212] Weeda at 5-7.

added costs along to their consumer-members. So, the Proposed Rules' application to electric generators will inevitably increase electricity prices. And these additional costs will impact low-income families more acutely and disproportionately. Low-income households spend a larger portion of household budgets on energy costs. For example, households are thought to have a "high energy burden" if more than 6% of the household income is spent on energy costs, and energy burdens are higher for "communities of color, rural communities, families with children, and older adults."[213] These high energy burdens affect housing conditions, which in turn, impact "physical and mental health, nutrition, and local economic development."[214]

Second, the Proposed Rules are expected to significantly impact reliability, as noted in Section VIII. This will disproportionately affect low-income families and disadvantaged communities. In the face of reliability impacts, many commercial consumers will resort to emergency back-up generators, which would disproportionately harm air quality affecting individuals that live in disadvantaged communities near those industrial sites. Meanwhile, lower-income residents would be unable to avail themselves of backup generators and would instead suffer the consequences of unreliable electricity. This violates basic energy justice principles which protect the ability of all people to have a "reliable, safe, and affordable source of energy."[215]

Third, EPA did not give sufficient consideration to concerns raised by environmental justice community stakeholders about the potential impacts of CCS and clean hydrogen infrastructure. As with most major infrastructure projects, the pipelines and storage facilities necessary for compliance under the Proposed Rules will have to go through state and federal permitting processes with robust community engagement. In light of the massive scale of CCS and clean hydrogen infrastructure deployment necessitated by the Proposed Rules, however, EPA's consideration of these issues thus far has been perfunctory and does not fulfill its obligations to meaningfully engage with stakeholders.

X. EPA Has Not Provided Sufficient Opportunity for Comment.

The Administrative Procedure Act (APA) requires agencies to "give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments."[216] Federal courts have interpreted this to mean that EPA must "make available to the public, in a form that allows for meaningful comment, the data the agency used to develop the proposed rulemaking."[217] The CAA contains similar requirements.[218] The CAA requires that "[a]ll data, information and documents [EPA relies on] shall be included in the docket *on the date of publication of the proposed* rules."[219] And in order for the public to have a meaningful opportunity to comment, it must have sufficient time to review, study, absorb, identify flaws with, and present counter-evidence to EPA's data. Congress, "after all, intended to provide 'thorough and careful procedural safeguards to [e]nsure an effective opportunity for public participation in the

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[213] American Council for an Energy-Efficient Economy. *How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden across the United States*. pp. 2, 5. September 2020. Available at: https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.
[214] *Id.* at 5.
[215] Aladdine Joroff. *Energy Justice: What It Means and How to Integrate It Into State Regulation of Electricity Markets.* p. 1. November 2017. Available at: https://elpnet.org/sites/default/files/2020-04/energy_justice_-_what_it_means_and_how_to_integrate_it_into_state_regulation_of_electricity_markets.pdf.
[216] 5 U.S.C. § 553(c).
[217] *Engine Mfrs. Association v. EPA*, 20 F.3d 1177, 1181 (D.C. Cir. 1994).
[218] 42 U.S.C. §§ 7607(d)(3),(5).
[219] *Id.* § 7607(d) (emphasis added).

rulemaking process.'"[220] As explained below, EPA's truncated comment period fails to provide stakeholders a meaningful opportunity to comment and is therefore unlawful.

EPA published the Proposed Rules on May 23, 2023, with a 60-day comment deadline of July 24. The next day, NRECA and the American Public Power Association (APPA) submitted a request to extend the deadline by an additional 60 days.[221] The original comment period was inadequate for at least three important reasons.

First, the Proposed Rules are not a single action – rather they are five actions.[222] The information to read and analyze include a 181-page preamble, a 359-page regulatory impact analysis, eight technical supporting documents (some of which contain several attachments), and dozens of other docket materials.

Second, EPA has repeatedly recognized that significantly longer comment periods are required for rules of similar complexity and significantly. For example, in previous versions of GHG performance standards for power plants under Section 111 of the CAA, EPA provided much longer comment periods. When EPA proposed the NSPS in January 2014, it provided a 120-day comment period following a 60-day extension of the original 60-day comment period. And when EPA proposed emission guidelines for existing sources later that year, the Agency provided a 165-day comment period, following a 45-day extension of the original 120-day comment period. Importantly, those comment periods were not concurrent – the NSPS comment period ended more than a month before the comment period for the proposed emission guidelines opened. The Proposed Rules are equally significant and EPA's arbitrary decision to shrink the comment period represents a significant and unreasoned departure from the Agency's prior interpretation of its public comment obligations.

Third, there were three other proposed rules concurrently open for comment directly affecting fossil fuel-fired EGUs.[223] The timing of these comment periods effectively reduced the time that cooperatives, and other segments of the electricity sector, could devote to their consideration of the Proposed Rules.

EPA has only paid lip service to these concerns. On June 12, EPA notified NRECA that the Agency had extended the comment period a mere 15 days to its current deadline, August 8. NRECA and APPA asked for a further 45-day extension noting that several entities, including the ISO/RTO Council, had requested more time to assess impacts of the Proposed Rules on reliability considerations.[224] No response was received.

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[220] *Sierra Club v. Costle*, 657 F.2d 298, 398 (D.C. Cir. 1981).

[221] Comments submitted by National Rural Electric Cooperative Association (NRECA) and American Public Power Association (APPA). May 24, 2023. Available at: https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0062.

[222] "The EPA is proposing revised new source performance standards (NSPS), first for GHG emissions from new fossil fuel-fired stationary combustion turbine EGUs and second for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. Third, the EPA is proposing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Fourth, the EPA is proposing emission guidelines for GHG emissions from the largest, most frequently operated existing stationary combustion turbines and is soliciting comment on approaches for emission guidelines for GHG emissions for the remainder of the existing combustion turbine category. Finally, the EPA is proposing to repeal the Affordable Clean Energy (ACE) Rule." 88 Fed. Reg. 33,240.

[223] These actions are: Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18,824 (March 29, 2023), with comments due May 30; National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 88 Fed. Reg. 24,854 (April 24, 2023), with comments due June 23; and Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 88 Fed. Reg. 31,982 (May 18, 2023), with comments due July 17.

[224] Comments submitted by National Rural Electric Cooperative Association (NRECA) and American Public Power Association (APPA). June 29, 2023. Available at: https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0159.

What is more, EPA added significant new data and information to the docket more than halfway through the 75-day comment period. This independently violates the APA's and CAA's requirement that EPA provide stakeholders a meaningful opportunity to comment. On July 7, EPA posted a memorandum to the docket titled "Integrated Proposal Modeling and Updated Baseline Analysis." The document, and the numerous attachments associated with it, updated EPA's analysis of the Proposed Rules' impacts. The updated modeling introduced significant changes to EPA's baseline modeling, which is critical to EPA's assessment of the impacts and viability of the proposals. But the D.C. Circuit has explained that if "documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment period prior to promulgation, then both the structure and spirit of section 307 would have been violated."[225]

EPA's unexpected mid-comment-period modeling update required NRECA and other stakeholders to begin their analysis anew to identify changes between the two model runs. Even though the CAA requires EPA to make all "data, information, and documents" it relies on available to the public,[226] EPA did not provide parsed files so that stakeholders could easily determine how individual units were modeled in the Updated Baseline and policy cases; this work had to be done manually with insufficient time. Indeed, as noted in Section VIII.B, NRECA had to limit its analysis of the IPM due to the lack of available information and time to review.

And there is good reason to believe that additional time would enable stakeholders to address the flaws in EPA's data and analysis. In a third joint extension request with APPA, NRECA explained the problems the updated modeling had introduced and expressed concern the remaining comment period is insufficient for a proper analysis that can be effectively incorporated into comments.[227] In addition, we alerted the Agency that we had uncovered issues that call into question the accuracy of certain aspects of the modeling mentioned earlier in these comments. These issues included at least three units that, according to EPA's Updated Baseline case, were modeled to have installed CCS by 2030.[228] Yet, in the policy case, these units show up as retired in 2028 or 2030. This result defies logic because a unit that EPA assumes would install CCS by taking advantage of the IRA's Section 45Q tax credit in the Updated Baseline should remain operational under the policy case.

In summary, EPA failed to provide stakeholders sufficient opportunity to provide comment given the breadth of the Proposed Rules, their significance, and the fact that EPA updated its underlying modeling more than halfway through the 75-day comment period. EPA's failure is in violation of the APA and the CAA, and the Agency has acted arbitrarily and capriciously in its determination not to give the public more opportunity to meaningfully comment.

XI. EPA Improperly Determined the Proposed Rules Would Not Significantly Impact Small Entities.

Under the RFA, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), EPA must assess the impacts of rules on small businesses, small not-for-profit organizations, and small

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[225] *Sierra Club*, 657 F.2d at 398; *see also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) (EPA violated the CAA's notice and comment requirements by failing to make updated forecast data available until one week before promulgation); *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 540 (D.C. Cir. 1983) (EPA improperly added evidence to the record near the end of the comment period).
[226] 42 U.S.C. § 7607(d)(3)
[227] Comments submitted by National Rural Electric Cooperative Association (NRECA) and American Public Power Association (APPA). July 18, 2023. Available at: https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0174.
[228] Marchetti Comments at 21.

governmental jurisdictions (collectively, small entities). If EPA determines that a proposed rule will have a "significant economic impact on a substantial number of small entities," it must convene a Small Business Advocacy Review (SBAR) panel[229] before the rule is proposed and prepare an initial regulatory flexibility analysis (IRFA).[230] If EPA determines that a proposed rule will not have a significant economic impact on a substantial number of small entities, the EPA Administrator may certify to such a conclusion and need not prepare an IRFA.[231] The certification statement must include a "factual basis for the certification."[232]

In order to determine if a rule will have a significant economic impact on a substantial number of small entities, EPA conducts "screening analysis" to determine if it can certify the rule.[233] The four steps in EPA's screening analysis, include: 1) determine which small entities are subject to the rule's requirements; 2) select appropriate measures for determining economic impacts on these small entities and estimate those impacts; 3) determine whether the rule may be certified as not having a significant economic impact on a substantial number of small entities; and 4) document the screening analysis and include the appropriate RFA statements in the preamble.[234]

While EPA held a Pre-Panel Outreach Meeting for Small Entity Representatives (SER) on December 9, 2022, which included 10 NRECA members, it subsequently decided not to proceed with the SBAR panel process. EPA accepted comments following the Pre-Panel Outreach Meeting,[235] but then came to the inaccurate conclusion that this rulemaking would *not* have a significant economic impact on a substantial number of small entities, choosing to abandon their obligation to convene a SBAR panel. EPA then improperly certified the Proposed Rules as ones that will not have a significant economic impact on a substantial number of small entities.

EPA's certification lacks a factual basis. EPA did not correctly determine which small entities would be subject to the rule's requirements and did not properly estimate costs. The supporting spreadsheet for EPA's RFA screening analysis only includes two electric cooperatives, Basin Electric Power Cooperative and Old Dominion Electric Cooperative, in the spreadsheet labeled "Small Entities." Inexplicably, EPA's sheet labeled "Final" only identifies PowerSouth Energy Cooperative, an electric cooperative that was not included in the "Small Entities" spreadsheet, as the sole affected electric cooperative.[236] These estimates are particularly surprising given that 10 electric cooperatives participated in the Pre-Panel Outreach meeting, an indication these cooperatives potentially have interest in building new natural gas units that may be covered

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[229] 5 U.S.C. § 609(b).
[230] 5 U.S.C. § 603.
[231] *Id.* at § 605(b).
[232] *Id.* The panel is comprised of a representative from the EPA, a representative of the Office of Advocacy of the U.S. Small Business Administration, and a representative from the Office of Information and Regulatory Affairs at the Office of Management and Budget. *Id.* at § 609(b). The panel provides SERs with a draft of the proposed rule as well as any analysis of small entity impacts and regulatory alternatives and collects advice and recommendations from the SERs. The panel must report on the SERs' comments and its findings. The report is made part of the rulemaking record.
[233] Environmental Protection Agency. *EPA's Action Development Process: Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act.* November 2006. Available at https://www.epa.gov/system/files/documents/2021-07/guidance-regflexact.pdf.
[234] *Id.* at 12.
[235] NRECA also participated in the Pre-Panel meeting and submitted comments on behalf of its members. Letter from Rae E. Cronmiller, Environmental Counsel, National Rural Electric Cooperative Association to the Environmental Protection Agency (Jan. 9, 2023). In addition, Western Farmers Electric Cooperative submitted comments. Those comments are available in the docket. *See* EPA-HQ-OAR-2023-0072-0023.
[236] EPA also includes Seminole's Electric Cooperative's plant on the spreadsheet titled "Additional HW capacity" but incorrectly classifies Seminole as a large entity.

by the Proposed Rules. In addition, for several North American Industry Classification Codes, EPA applied outdated SBA size standards.[237] In February 2023, SBA issued a final rule updating these size standards.[238]

Further, EPA severely underestimates compliance costs. First, EPA hides the true economic impacts of the Proposed Rules by only estimating the economic impact of the NSPS on small EGU entities in one year – 2035.[239] Clearly, the cost impacts of the Proposed Rules will not be limited to one year. In addition, EPA neglected to develop adequate projections for key direct costs associated with the Proposed Rules, including materials, permitting, and construction of infrastructure necessary for compliance. These failures have been explained in detail in Section IV of these comments. By underestimating these direct costs, EPA erroneously determined using its screening analysis process that the cost-to-revenue or cost-to-sales test was satisfied, and that no affected small entities would experience annual compliance costs in excess of 1% of revenues.[240] These errors have resulted in the Agency incorrectly determining the Proposed Rules would not significantly affect small entities and improperly certifying.

While EPA maintains the certification decision is correct, the Agency's actions belie that claim. On July 27, 2023, EPA convened a SBAR panel with a SER meeting scheduled to take place on August 10, *after* the comment period closes. A final SBAR panel report must be completed within 60 days of the panel being convened.[241] EPA must make that report available for public comment. Furthermore, it should redo all of its economic impact analysis, including its threshold analysis and publish an IRFA for public comment by issuing a supplemental notice of proposed rulemaking (SNPRM) with an adequate comment period so that the public can weigh in on EPA's analysis and any alternatives provided and discussed by SERs. If EPA fails to issue an SNPRM with the alternatives, then under the APA those alternatives cannot be considered for inclusion in a final rule – which would violate EPA's obligations under the RFA and SBREFA to develop alternatives for proposed rules.

XII. EPA Should Not Consider Options to Make the Proposed Rules More Stringent.

Throughout the Proposed Rules, EPA asks for public comment on whether to make certain requirements more stringent. These include alternatives lowering the MW threshold for existing natural gas units and accelerating the retirement deadlines in the subcategories presented for existing coal EGUs. NRECA urges the Agency to avoid any such measures.

As discussed at length in these comments, the Proposed Rules in their entirety are unworkable as published and will jeopardize electric cooperatives' ability to provide affordable, reliable, and safe electricity. Making any aspect of the Proposed Rules more stringent would only exacerbate these challenges.

XIII. Conclusion

EPA's Proposed Rules clearly violate the CAA and Supreme Court precedent. The Agency relies on unproven technologies not yet commercially viable or available in many parts of the country. The Proposed Rules are based on inadequately demonstrated technology and unachievable emissions reductions that must occur on unworkable timelines. They are grounded in speculative assumptions that these technologies will somehow be economical and widely available at some point years in the future. EPA also fails to recognize

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[237] RIA at 5-8. The codes are: 221111, 221112, 221113, 221114, 221115, 221117, 221118, 221121, 221121, 221122, and 221210.
[238] Small Business Size Standards: Manufacturing and Industries With Employee-Based Size Standards in Other Sectors Except Wholesale Trade and Retail Trade, 88 Fed. Reg. 9,970.
[239] RIA at 5-5.
[240] RIA at 5-5-5-11.
[241] 5 U.S.C. § 609(b)(5).

the massive infrastructure development necessary to support these technologies. Accordingly, EPA should withdraw the Proposed Rules in their entirety.

NRECA appreciates the opportunity to comment on EPA's Proposed Rules. Should you have any questions, please contact Dan Bosch, regulatory affairs director, at dan.bosch@nreca.coop, or Bobby Hamill, senior director, environmental policy, at bobby.hamill@nreca.coop.

Sincerely,

Jim Matheson
CEO, NRECA

Appendix 4

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION,	)	
Petitioner,	)	
v.	)	Case No. 24-1122
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,	)	
Respondents.	)	

DECLARATION OF JIM MATHESON

I, Jim Matheson, declare as follows:

1. My name is Jim Matheson. I am the chief executive officer at the National Rural Electric Cooperative Association ("NRECA"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. The facts set forth in this declaration are based on my personal knowledge and information that I have reviewed and rely on in the ordinary course of my work as CEO. If called and sworn as a witness, I could and would competently testify to the matters discussed in this declaration.

2. I have been employed at NRECA since 2016. I hold a bachelor's degree in government from Harvard University, as well as a master's degree in business administration in Finance and Accounting from the University of California, Los Angeles. From 2001 to 2015, I served as a member of Congress in the United States House of Representatives representing the State of Utah. Prior to entering government service, I worked in the energy industry for 13 years. As chief executive officer at NRECA, I am responsible for overseeing all aspects of the organization including planning, programs, operations, and controls.

3. This declaration is submitted in support of NRECA's Petition for Review and Motion for Stay of EPA's final rule 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*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

4. This declaration describes NRECA's role and its membership, discusses how electric cooperatives plan and finance capital projects, and describes the Rule's immediate and irreparable impacts on electric cooperatives and grid reliability.

NRECA AND ITS MEMBERS

5. NRECA is the national trade association representing nearly 900 not-for-profit electric cooperatives and other rural electric utilities. NRECA was formed in 1942 by rural electric cooperative leaders to provide a unified voice for cooperatives and to represent their interests in Washington, D.C. NRECA's mission is to promote, support, and protect the community and business interests of electric cooperatives. NRECA advocates on behalf of its members before Congress and federal agencies, including the EPA. NRECA's member cooperatives include 64 generation and transmission ("G&T") cooperatives and 832 distribution cooperatives.[1]

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[1] National Rural Electric Cooperative Association, *Electric Co-op Facts and Figures* (April 19, 2024), https://tinyurl.com/y89bvn4e ("Co-op Facts").

6. America's electric cooperatives comprise a unique sector of the electric industry. These not-for-profit entities are independently owned and democratically governed by the people they serve. They exist in rural areas, where low populations and incomes have not attracted for-profit power companies. Electric cooperatives are focused on providing affordable, reliable, and safe electric power in an environmentally responsible manner. Electric cooperatives support common sense solutions to environmental impacts.

7. Each cooperative is governed by a board of directors elected from its membership. The G&T cooperatives generate and transmit power to distribution cooperatives that then provide that power to consumer-members. Collectively, G&T cooperatives generate and transmit power to nearly 80% of distribution cooperatives, which in turn provide power directly to consumer-members at the "end of the line"—*i.e.*, the location where electricity is consumed. The remaining distribution cooperatives obtain power directly from other generation sources within the electric utility sector. Both distribution and G&T cooperatives share an obligation to

serve their consumer-members by providing affordable, reliable, and safe electric service.

8. Electric cooperatives provide power to one in eight Americans and serve as engines of economic development for 42 million people across 56% of the nation's landmass. They own and maintain 2.7 million miles, or 42 percent, of the nation's electric distribution lines and serve large expanses of the United States that are primarily residential and typically sparsely populated. Those characteristics make it comparatively more expensive for rural electric cooperatives to operate than the rest of the electric sector, which tends to serve more compact, industrialized, and densely populated areas.

9. Since electric cooperatives serve areas with low population density, costs are borne across a base of fewer consumers and by families that spend more of their limited resources on electricity than do comparable customers of municipal-owned or investor-owned utilities. Using data from the U.S. Energy Information Administration and other sources, NRECA estimates that rural electric cooperatives serve an average of eight consumers per mile of line and collect annual revenue of approximately $19,000 per mile

of line. In contrast, for the rest of the industry, the averages are 32 customers and approximately $79,000 in annual revenue per mile of line.

10. Many cooperative consumer-members are among those least able to afford higher electricity rates. Electric cooperatives serve 92% of persistent poverty counties in the United States.[2] In 2022, the average (mean) household income for electric cooperative consumer-members was 12% below the national average.

11. The electricity supplied by cooperatives is vital to rural economies. Rural development requires access to affordable and reliable electric power. Regulations that are not cost-effective and increase the cost of producing that electricity, or that threaten its availability, thus pose serious threats to economies in large segments of rural America.

12. Electric cooperatives rely on a diversity of resources to affordably and reliably meet their consumer-members' energy needs. Because of the comparatively smaller scale at which many cooperatives operate, cooperatives rely on fewer generation resources than other parts of

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[2] Co-op Facts, *supra* n.1.

the utility sector. Any actions affecting the availability of these resources disproportionately impact cooperatives and their consumer-members.

13. Electric cooperatives continue to increase the use of renewable energy resources; leverage distributed energy resources and storage; adopt energy efficiency programs; monitor and explore developments related to nuclear energy; and work to enable an electrified economy.

14. Individual cooperatives and NRECA also are leading efforts to develop carbon capture technologies. NRECA is a sponsoring partner of the National Carbon Capture Center, the U.S. Department of Energy's primary carbon capture research facility, and of the Wyoming Integrated Test Center, a public-private partnership. The host site for the Wyoming Integrated Test Center is Basin Electric Power Cooperative's ("Basin Electric") Dry Fork Plant. The State of Wyoming, Basin Electric, NRECA, and Tri-State Generation and Transmission Association are supporting partners.

15. As not-for-profit entities, electric cooperatives are unique in the way they are financed. Cooperatives have no equity shareholders who can bear the costs of stranded generation assets or investment in new or

alternative generation resources. Cooperatives do not have a rate of return on equity as do investor-owned utilities. All costs are passed through directly to each cooperative's consumer-members via increased electric rates. Simply put, cooperatives do not profit when they build generation assets, and they build only what is necessary to affordably and reliably meet their consumer-members' energy needs.

COOPERATIVE CAPITAL PROJECT PLANNING AND FINANCING

16. Cooperatives must engage in capital project planning years before making any new investments. Building new generation resources and related infrastructure requires many years of advance planning.

17. To construct new electric infrastructure, cooperatives must:

- create a site plan,
- apply for the necessary permits,
- obtain needed property rights,
- finalize technology studies,
- participate in regional or conduct transmission and interconnection studies,
- complete regulatory filings,
- confirm the fuel source,

- construct or contract for pipelines to be built or capacity to be used, if needed,
- sign construction contracts, and
- construct the new resource.

18. If a cooperative pursues federal financing or requires federal permits or other approvals for new infrastructure, compliance with the National Environmental Policy Act ("NEPA") and other federal requirements may be triggered. Any such reviews must be completed before decisions on federal financing, permits, or approvals can be made. Timelines for these reviews are unpredictable and can be lengthy, particularly if they draw legal challenges.[3]

19. Because of their not-for-profit nature, cooperatives maintain only marginal cash reserves for anticipated operating expenses and unforeseen events. For that reason, financing the significant capital investment required for new generation, transmission, and other infrastructure projects necessarily requires reliance on debt sourced from

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[3] *See, e.g.*, Council on Envtl. Quality, *Environmental Impact Statement Timelines (2010-2018)* at 1 (June 12, 2020), https://tinyurl.com/2w9wwxr3.

entities such as the U.S. Department of Agriculture's Rural Utilities Service ("RUS"), National Rural Utilities Cooperative Finance Corporation, and CoBank. The Cooperative Finance Corporation is a member-owned, nonprofit cooperative organized in 1969 to raise funds from capital markets to supplement RUS loan programs. CoBank is a national cooperative bank and a member of the Farm Credit System, a nationwide network of banks and retail lending associations chartered to support the borrowing needs of U.S. agricultural interests and the nation's rural economy.

20. Taking on new debt to build new resources while servicing old debt on stranded assets jeopardizes a cooperative's ability to meet its loan covenants. This forces the cooperative to risk default on its loans or raise rates. Since the only means to generate more margin is to raise rates, ultimately, it is the consumer-members at the end of the line who bear the cost of regulations through increased electric rates.

21. G&Ts provide wholesale electricity to their member distribution cooperatives at rates that reflect their costs plus a small operating margin that serves as a cash reserve for unforeseen or unplanned events. Their

wholesale rates cover only costs associated with debt service plus a small cost of operating margin and do not include equity contributions substantial enough to fund large capital projects. G&Ts therefore carry a significant amount of debt relative to the investor-owned segment within the electric utility industry because of how they must acquire capital. Specifically, G&Ts have no outside equity shareholders like investor-owned utilities and thus do not have the option of acquiring capital through private equity. G&T financing also differs from that of the municipally owned utilities as they do not have access to municipal bonds. G&T financing primarily comes from issuing debt that is subsequently recovered through rates paid by member distribution cooperatives (and ultimately their consumer-members). While new federal incentive programs (loan guarantees, grants and tax credits) have been made available to cooperatives as discussed below, there is uncertainty surrounding the ability to access those funds in a timely manner.

22. Historically, cooperatives have taken advantage of RUS financing for capital projects. Some G&Ts, however, have found it necessary to pursue other financing options. While RUS loans can be attractive to

cooperatives because of lower interest rates, RUS financing is not without challenges. These challenges include loan restrictions, lengthier approval processes (including NEPA reviews, *see* 7 C.F.R. Part 1970), and the significant amount of capital required.

23. Alternative sources of financing, including the Cooperative Finance Corporation and CoBank, however, come with their own requirements. Because G&Ts are relatively smaller in size than investor-owned utilities and historically have had limited activity in the capital markets, G&Ts and their credit attributes are not as well known or understood by some potential lenders as compared to generators within other electric utility segments. Private financing also typically comes with higher interest rates than RUS loans.

24. G&Ts as cost-based cooperatives generally have retained fairly low equity-to-total-capitalization ratios, often between 10 and 20 percent. Those low ratios at times affect credit analyses, including the assignment of credit ratings, which in turn affects the cost of debt capital and other aspects of a utility's operations. Because G&Ts are dependent on debt financing and

lack any access to equity markets, they must have access to these debt markets by maintaining sufficient credit ratings in order to fund capital expenditures. Large capital expenditures relative to the cooperative's total assets can cause significant deterioration in credit metrics, making it more difficult, more expensive, or both to finance needed projects.

25. As described in the accompanying declarations of NRECA's members, compliance with the Final Rule will require dramatic increases in G&T capital expenditures. If G&Ts are required to increase their capital expenditures, their equity-to-total-capitalization ratio will be adversely affected and will result in pressure on, and likely downgrading of, their credit ratings. The challenges of financing unproven technologies required by the Final Rule, such as carbon capture and storage ("CCS"), will only increase this pressure as they are viewed as speculative investments.

26. Because G&Ts operate at cost, they must pass along capital costs directly to their member distribution cooperatives (and ultimately their consumer-members) through increased rates. The rural nature of electric cooperatives' business (and the small number of customers per mile of

distribution line discussed above) means that fewer customers exist to share those costs. Electric cooperatives' rural customers already spend more of their limited incomes on electricity than other consumers, and they are accordingly disproportionately affected by rate increases.

27. Electric cooperatives may not, however, be free to raise rates to their members to pay for debt service associated with needed improvements. Cooperative board members, who live in the communities they serve, must approve any rate increases in the first instance. Boards are careful stewards of their members' resources and mindful of the economic impact of rate increases to end of line consumer-members. Adding to this complexity, cooperatives in 23 states are subject to mandatory or optional rate regulation by state public utility commissions, and eight G&Ts are subject to the Federal Energy Regulatory Commission's rate regulation.

28. Recently enacted laws, including the Inflation Reduction Act, have provided incentives for cooperatives to deploy energy technologies, including renewables and other carbon free resources. These incentives include a nearly $10 billion grant program through the U.S. Department of

Agriculture and "direct pay" tax credits through the U.S. Department of the Treasury. Cooperatives are eagerly pursuing these opportunities. For example, cooperatives submitted letters of interest for four times the available funding through the U.S. Department of Agriculture's grant program.

29. These financial opportunities are insufficient, however, to meet the compliance burdens established by the Final Rule. The costs associated with compliance far exceed any sum available through these programs. And as discussed above, NEPA reviews—with their lengthy and uncertain durations—may be required. Whether these reviews can be completed in time to take full advantage of these financial opportunities is far from certain.

THE FINAL RULE'S IMPACTS ON RURAL ELECTRIC COOPERATIVES AND GRID RELIABILITY

30. The Final Rule jeopardizes the ability of rural electric cooperatives to fulfill their mission to provide affordable, reliable, and safe electricity to their consumer-members. While the Final Rule's compliance deadlines do not kick in until 2030, EPA itself "assumes" the "work" toward

achieving compliance will begin in "June 2024." 89 Fed. Reg. 39874. NRECA's members must immediately begin taking costly steps to prepare.

31. The Final Rule requires the use of emissions control technology that is not commercially viable on an unreasonably expedited timeframe. Because of the near certainty that NRECA's G&T members will not be able to comply, many existing coal-fired power plants will be forced to retire before the end of their useful life. Of necessity, this will force generation to shift to other sources—those preferred by EPA. This loss of dispatchable, always-available electric generation capacity will require G&Ts to make decisions regarding how to secure replacement power. They can do that either by building new generation or through market purchases. Either path requires planning and implementation activities, which by their very nature have significant costs. G&Ts opting to develop new generation facilities would need to make substantial immediate expenditures.

32. Because cooperatives must make business decisions all at once to comply with the Final Rule, the Final Rule will have immediate and irreparable economic consequences if it is not stayed until the courts have

had a full opportunity for review. Before any state plans implementing the Final Rule are submitted and certainly before this litigation is resolved, NRECA's G&T members will need to immediately begin taking steps to ensure they can continue to provide power to their members.

33. This Rule will force the early retirement of dispatchable, always-available electric generating resources without adequate replacement capacity to keep the lights on and power flowing to the end of line cooperative consumer-members.[4] For example, among the 75+ coal-fired units that are wholly or partially owned by NRECA members, NRECA knows of only 3 units that are in a position to even consider attempting 90% CCS (2 of which are at the same plant).

34. To develop or obtain replacement capacity, cooperatives may require board approval of an updated resource plan that identifies viable replacement electric generating resources and specific details about

[4] Indeed, many NRECA members have submitted concurrent declarations making this exact point. *See, e.g.*, Hasten ¶ 33; McCollam ¶ 54; Purvis ¶ 49; Tudor ¶ 21. (Citations using a "¶" refer to the declarations in the exhibits to NRECA's Motion for Stay.)

associated costs, project financing, siting, environmental reviews, permitting, supply chain availability, and generation interconnection to an already capacity-constrained transmission grid. These steps may also include negotiating fuel supply and pipeline contracts, power purchase agreements with third-party power providers, construction contracts, and other irreversible commitments.

35. One obvious source of replacement power for prematurely retired coal-fired power plants is to shift generation by building new natural gas-fired power plants, since those plants are also dispatchable resources. However, the Final Rule's standards for new electric generating units operating at baseload capacity, based on CCS, are not attainable.[5] And it makes no sense to build an expensive, state-of-the-art combined-cycle plant and then run that plant less than half the time, as the Rule requires for "intermediate" load units.

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[5] NRECA members have also made this point in their individual declarations. *See, e.g.*, Grooms ¶¶ 21-22; Hochstetler ¶¶ 27-29; McLennan ¶¶ 21-52; Porath ¶¶ 17-18.

36. Accordingly, the only potential option is to build a large number of low-capacity combustion turbines ("CTs") all running at a capacity factor of 20% or less. This is highly inefficient and a tremendous waste of resources, all for no environmental benefit. That wastefulness is particularly concerning for cooperatives, which must pass along these costs to end of the line consumer-members. For example, to achieve 200 MW of reliable baseload generation, G&Ts will need to build at least 1,000 MW worth of CTs—and sometimes even more than that in order to satisfy the margin requirements that are required to assure reliability.

37. Another potential alternative is to build renewable generation resources, like wind and solar. This is unworkable, because unlike dispatchable resources that are always available, renewables are intermittent and undependable. Renewables can generate power only under suitable conditions (*e.g.*, a sunny day for solar resources, or a windy day for wind turbines). For instance, according to the U.S. Energy Information Administration, "U.S. electricity generation from wind turbines decreased for the first time since the mid-1990s in 2023 despite the addition of 6.2

gigawatts (GW) of new wind capacity last year."[6] Thus, renewables cannot be reliably called upon as needed at times of peak demand, which can occur at night, on cloudy days, and when the wind is not blowing.[7] Even wind or solar generation that is co-located with batteries cannot be used in the same manner as dispatchable generation, because batteries only store enough energy to be used for a matter of hours.

38. The final option is to purchase market power, if it is available. Like any market, however, electricity markets are subject to the volatility that flows from the laws of supply and demand. The Final Rule increases this volatility by forcing the disorderly retirement of always-available generating assets without adequate replacement capacity. This will result in more utilities depending on market power to meet load requirements, all while chasing a shrinking supply of power. At the same time, the North American Electric Reliability Corporation ("NERC") has found that rising peak

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[6] U.S. Energy Information Administration, *Wind generation declined in 2023 for the first time since the 1990s* (Apr. 30, 2024), https://tinyurl.com/253y2vwk.

[7] NRECA members have made this point, too, in their concurrently submitted declarations. *See, e.g.*, Hollandsworth ¶ 10; Soderberg ¶ 22.

demand forecasts are contributing to lower reserve margins (*i.e.*, the amount of unused available capacity of an electric power system during peak demand periods) projected for nearly all power markets. This volatility, and the limited availability of power altogether, makes adequate planning extremely difficult. These uncertainties are particularly harmful to cooperative consumer-members, who ultimately must bear the costs associated with unforeseen demand or supply shocks.

39. Providing reliable and affordable electricity to the consumer-members at the end of the line is an essential component of cooperatives' mission. As discussed above and in the attached declarations of NRECA's members, EPA's Final Rule will lead cooperatives (and other utilities) to prematurely retire coal-fired power plants and make it uneconomic to build new natural gas plants, thus shifting generation to lower CO_2 emitting sources. Because renewables cannot sufficiently replace the capacity retired as a result of the Final Rule with the same attributes, the electric grid will face a significant shortfall of always-available generation capacity that is unable to keep up with demand.

40. Already the electric grid is struggling to keep up with existing energy load requirements. NERC's recent reliability assessments have pointed to "the disorderly retirement of traditional generation (with its inherent ability to provide essential reliability services and balance energy reserves) as one of the biggest challenges facing the grid."[8] NERC has also declared that "industry faces mounting pressure to keep pace with accelerating electricity demand, energy needs, and transmission system adequacy as the resource mix transitions."[9] According to NERC, all or parts of 19 states are at high risk of rolling blackouts during normal peak conditions.[10] And most of the rest of the country is at similar risk when demand for electricity spikes during exceedingly hot or cold temperatures. Recently, the U.S. Energy Information Administration projected a 4%

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[8] North American Electric Reliability Corporation, *2022 Annual Report* at 13 (Feb. 2023), https://tinyurl.com/4zum74wb.

[9] North American Electric Reliability Corporation, *Long-Term Reliability Assessment 2023 Infographic* (Dec. 2023), https://tinyurl.com/bde3e8tj.

[10] North American Electric Reliability Corporation, *2023 Long-Term Reliability Assessment* (Dec. 2023), https://tinyurl.com/4k62ahaj.

increase in residential electricity consumption in 2024.[11] And in recent years, near-term projections of load growth have skyrocketed due to energy needs of data centers and other large projects. The rapidly increasing demand will exacerbate reliability challenges.

41. On top of this rising demand from data centers and industrial development, the increasing electrification of the economy will require operators to increase power on the grid. The Inflation Reduction Act contained provisions designed to accelerate electrification—from increasing consumer purchases of electric vehicles and heat pumps to substantially ramping up hydrogen production—all in the hopes of achieving net-zero economy-wide emissions in the coming decades. Recent modeling by the Electric Power Research Institute concluded that achieving net-zero economy-wide emissions by 2050 could require generation capacity to

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[11] U.S. Energy Information Administration, *Short-Term Energy Outlook* (April 9, 2024), https://tinyurl.com/mryhwhey.

increase by as much as 480%.[12] At the same time, increasing electrification in other sectors of the economy (for example, transport) calls for a multi-fold expansion of the transmission grid, not to mention a drastic increase in overall supply. EPA's Final Rule would result in the premature retirement of generation capacity at a time when total generation capacity needs to be substantially increased rather than decreased.

42. Whether G&Ts choose to construct numerous capacity factor-limited CTs, develop renewable resources, or try to purchase generation capacity in what will likely be a crowded and volatile market, they will have to make enormous capital investments to comply with the Final Rule. As explained above, to pay for that high-cost financing and additional capital costs, G&Ts will have to raise rates significantly and unduly burden their rural, low-income consumers. In addition, they will still be carrying outstanding debt from prematurely retired assets, which will in turn negatively affect their credit ratings. Their rates likely will be forced to

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[12] Electric Power Research Institute, *LCRI Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis, Executive Summary* (last updated Mar. 9, 2023), https://tinyurl.com/33jsnvrz.

increase even further to cover the costs of generation while continuing to pay for the sunk costs and outstanding debt associated with prematurely retired units. Higher rates may mean that cooperatives are no longer able to offer affordable rates.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 10th day of May, 2024, in Arlington, VA

J Matheson

Jim Matheson

Appendix 5

DECLARATION OF GAVIN MCCOLLAM

I, Gavin A. McCollam, declare as follows:

1. My name is Gavin A. McCollam. I am the Senior Vice President and Chief Operating Officer of Basin Electric Power Cooperative ("Basin Electric"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called upon and sworn as a witness, could and would competently testify to them.

2. I have more than 35 years of experience in the electric generation industry. I have been employed at Basin Electric since 1989. I hold an associate's degree from Bismarck (North Dakota) State College, a bachelor's degree in mechanical engineering from North Dakota State University, and a master's degree in systems management from the University of Southern California. I am also a registered professional engineer.

3. Basin Electric is a member of the National Rural Electric Cooperative Association ("NRECA"). This declaration is submitted in support of NRECA's and North Dakota's legal challenges to the rule 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, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

I. BASIN ELECTRIC

4. I am familiar with how the Final Rule will affect Basin Electric, the electric markets, and suppliers of electric equipment and services, as well as Basin Electric's consumer members.

5. Basin Electric is a not-for-profit generation and transmission ("G&T") cooperative incorporated in 1961 to provide supplemental power to a consortium of rural electric cooperatives. Those member cooperatives—140 of them—are Basin Electric's owners. Through them, Basin Electric serves approximately three million consumer members in an area that covers roughly 500,000 square miles across nine states: Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. Basin Electric's end-use consumer members across these nine

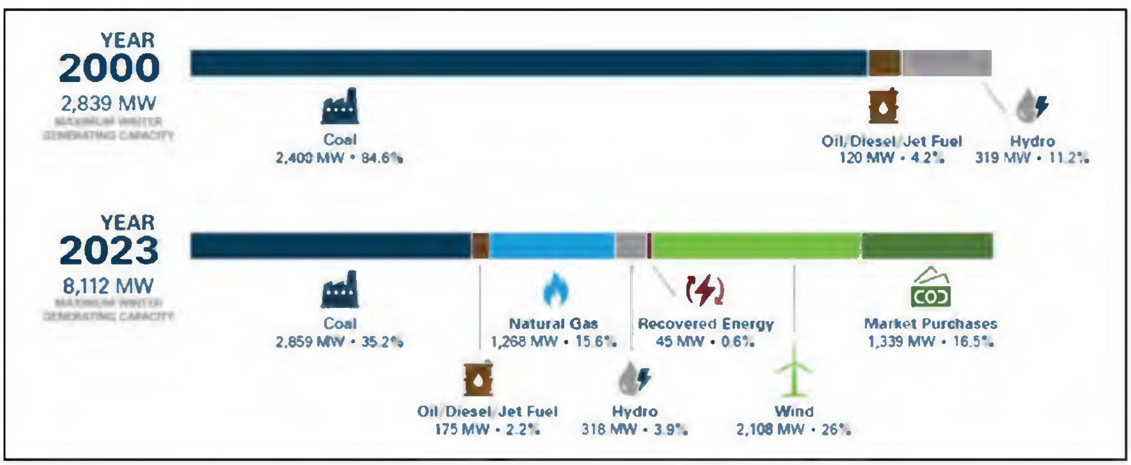
states include residential, farm, commercial, industrial, and irrigation electric consumers. In 2022, Basin Electric's farm and residential consumer members accounted for 29% of its megawatt-hour ("MWh") sales, while the commercial and industrial consumer members accounted for 68% of the MWh sales.

6. As of the end of 2023, Basin Electric had an asset base of $8 billion and operated 5,219 megawatts ("MW") of wholesale electric generating capability and had 8,112 MW of generating capacity within its portfolio. Those owned electric generation facilities are located in the states of Iowa, Montana, North Dakota, South Dakota, and Wyoming. Basin Electric's members provide electric service to 75% of the persistent poverty counties located within the nine states served, according to the 2023 persistent poverty data compiled by the U.S. Department of Agriculture Economic Research Service.

7. In order to provide the reliable electric supply that the member owners expect, Basin Electric is committed to an "all of the above" generating strategy which calls for multiple generating units utilizing

diverse fuel types (both fuel-fired and renewable resources) at dispersed locations. Basin Electric has invested and committed to approximately $7 billion dollars in developing new renewable energy resources, and it currently has a renewable energy portfolio of approximately 2,100 MW (as of the end of 2023). The other components of Basin Electric's portfolio include coal-fired generation (≈2,850 MW), natural gas-fired generation (≈1,250 MW), market purchases (≈1,350 MW), hydroelectric (≈300 MW), other fossil fuels (≈175 MW), and recovered energy (≈50 MW).

8. Basin Electric's diverse portfolio of electricity generation is a result of the significant investments that Basin Electric has made in the past two decades, as the following infographic summarizes:



9. Basin Electric has many electric generating units ("EGUs") that fall within the scope of the Final Rule ("affected EGUs") and thus must comply with the Final Rule's stringent new standards for coal-fired steam units. These affected EGUs have remaining useful lives that would be significantly shortened under the Final Rule absent massive amounts of new investment to cover all the compliance costs that the Rule creates. These substantial costs would fall on Basin Electric, and ultimately, on our rural consumer members. The table below identifies the EGUs that would be impacted if the Final Rule takes effect. The table also shows the results of Basin Electric's preliminary analysis of the approximate capital costs to comply with the Final Rule.

Affected EGU	**State**	**Compliance Strategy**	**≈ Capital Cost**
Dry Fork Station	WY	Long Term: CCS at 90%.	$2 billion
Antelope Valley Station Unit 1	ND	Medium Term: Co-fire with natural gas by 2029; retire by 2038.	$104 million
Antelope Valley Station Unit 2	ND	Medium Term: Co-fire with natural gas by 2029; retire by 2038.	$104 million

Leland Olds Station Unit 1	ND	Applicability exemption; retire by 2031.	$0
Leland Olds Station Unit 2	ND	Applicability exemption; retire by 2031.	$0
Laramie River Station Unit 1*	WY	Unknown	Unknown
Laramie River Station Unit 2*	WY	Unknown	Unknown
Laramie River Station Unit 3*	WY	Unknown	Unknown
Walter Scott Jr. Energy Center Unit 3**	IA	Unknown	Unknown
Walter Scott Jr. Energy Center Unit 4**	IA	Unknown	Unknown
George Neal South Generating Station Unit 4***	IA	Unknown	Unknown
Replacement Generation		Unknown	Unknown

*Basin Electric owns an undivided joint interest in Laramie River of approximately 42%.

** Basin Electric has a power purchase agreement with one of its members for the output of their ownership interest in Walter Scott Jr. Energy Center Unit 3 and Unit 4. Through those agreements with its members, Basin Electric has financial responsibility for approximately 4% of Unit 3 and approximately 6% of Unit 4. Such rights do not provide the ability to make decisions on these Units.

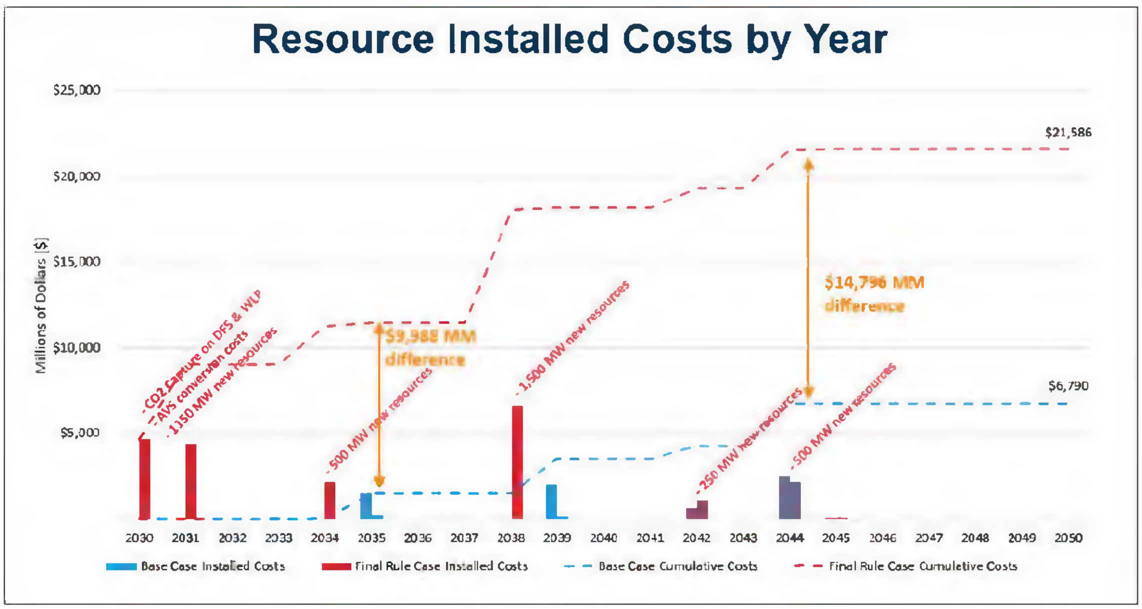
*** Basin Electric has two power purchase agreements with two of its members for the output of their ownership interest in George Neal South Unit 4. Collectively, Basin Electric has financial responsibility for approximately 16% of the unit. This percentage does not provide the ability to make decisions on this unit. MidAmerican Energy Company, as the majority owner and the operator of the unit, has this right and responsibility.

10. Basin Electric is currently in the middle of a massive generation and transmission buildout necessary to address load growth and long-term grid stability for its growing membership. Basin Electric is constructing an addition of approximately 580 MW of natural gas simple cycle generation to the existing Pioneer Generation Station, at a cost of approximately $800 million, that is expected to come online in 2025. Basin Electric is also actively investigating the need for more than 1,000 MW of dispatchable generation in western North Dakota by 2030 to address members' needs. This new generation will also need to comply with the Final Rule. In addition to these active generation projects, Basin Electric is also constructing over 300 miles of high voltage transmission line projects along with several major substation projects. The transmission line projects include the Roundup-to-Kummer Ridge 345kV project, the Leland Olds Station-to-Tande 345kV

project, and the Tande and Wheelock-to-Saskatchewan 230kV project. These projects have a combined cost of more than $700 million.

11. The table and graph below illustrate the projected capital cost associated with the planned generation expansion without the Final Rule ("Base Case"), as well as the projected capital cost associated with meeting load growth and complying with the Final Rule through 2045 ("Final Rule Case"). The incremental capital cost through 2035 to comply with the Final Rule is nearly $10 billion. **The incremental capital cost through 2045 to comply with the Final Rule is more than $14 billion.** These costs do not include any costs that would be associated with Final Rule compliance at Laramie River, Water Scott Jr. Energy Center, or George Neal South Generating Station.

2030-2045	Base Case	Final Rule
Total Need (SPP):	3,000 MW	3,500 MW
Total Need (RMPA):	350 MW	450 MW
Total Need (MISO):	45 MW	45 MW
Total Resource Need:	3,395 MW	3,995 MW
Avg Resource Costs:	@ ~$2,000/kW	@ ~$4,400/kW
Total Cap Costs:	$6,790,000,000	$17,578,000,000
Net Incremental Costs to Resource Expansion		+$10,788,000,000
NG Conversion		+$ 208,000,000 +
Carbon Capture on DFS + WLP Resource		+$ 3,800,000,000
Total Incremental Costs		**=$14,796,000,000+**



II. OVERVIEW OF THE FINAL RULE

12. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam electric generating units, under Section 111(d).

89 Fed. Reg. 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* 39902. Both types of units must meet emissions limits equal to what EPA believes 90% carbon-capture-and-sequestration can achieve. Existing units that cannot achieve this must shut down. New units that cannot achieve this must drastically limit their output of electricity.

13. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* For purposes of implementing these subcategorizations for a particular unit, EPA recognizes only those retirement commitments that are made "federally enforceable" via inclusion in a State plan. *Id.* 40000. State plans are due to EPA in 24 months. *Id.* 39997.

14. The first (and default) subcategory is for "long-term" units, which EPA defines as units that "intend to operate past January 1, 2039." *Id.* 39801. EPA says that the best system for this subcategory is CCS that

captures 90% of the CO_2 from a unit. *Id.* 39845. This system begins with the design, engineering, and installation of CO_2 capture technology. *Id.* 39846. Then the captured CO_2 must be transported (usually via pipeline) to a site that can permanently sequester it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in "June 2024." *Id.* 39874. And the Rule requires unit operators to complete that work before January 1, 2032. *Id.* 39801.

15. The second subcategory is for "medium term" units: those that commit "to permanently cease operations" sometime "after December 31, 2031" but "before January 1, 2039." *Id.* 39841; *see id.* 39958. EPA says that best system for this subcategory is "[n]atural gas co-firing at 40 percent." *Id.* 39801. That means transforming a coal unit into a unit that combusts both coal and natural gas. *See id.* Just "[a]s in the timeline for CCS," EPA "assumes" that "work" toward co-firing will begin in June 2024. *Id.* 39893. And the Rule requires medium-term unit operators to complete that work before January 1, 2030. *Id.* 39845.

16. Third, the Rule establishes an "applicability exemption" for units that commit "to permanently cease operation before January 1, 2032." *Id.* 39841. These units "are not regulated by" the Rule. *Id.* 39843. However, if such a unit then "continues to operate past [that date], then it is no longer exempt," *id.*, putting the unit "in violation of" the State plan and the Clean Air Act, *id.* 39991.

17. *New gas-fired combustion turbine units*. For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* 39908. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* 39917. "Intermediate load" units (those that sell 20-40%) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.* "Base load" units (those sell more than 40%) must comply with a "multi-phase standard of performance." *Id.* 39923. Phase I is "based on the performance of a highly efficient combined cycle turbine" and has "an

immediate compliance date." *Id*. 39903. Phase II is based on 90% CCS and has "a compliance date of January 1, 2032." *Id*.

III. IMPACTS TO AFFECTED EGUs

18. *Impacts at Dry Fork Station — "Long Term" subcategory.* The Dry Fork Station ("Dry Fork") consists of one 405 MW affected EGU located in Gillette, Wyoming. It began operation in 2011, with a construction cost of $1.35 billion. The station uses pulverized subbituminous coal technology and the latest generation of pollution control technologies resulting in very low emissions. As water is a scarce resource in Wyoming, Dry Fork uses air cooling. The plant location has potential area to site a carbon capture unit. Dry Fork is home to the Wyoming Integrated Test Center and the Wyoming CarbonSAFE project, both of which receive funding from the Department of Energy and the state of Wyoming for research projects that aim to help develop CCS technology.

19. Dry Fork is a relatively new coal-fired power plant, and its remaining depreciable life extends into the early 2070s. As a result, Basin Electric plans to leave Dry Fork within the Final Rule's default category for

"long term" EGUs. That decision requires Basin Electric to achieve 90% CCS at Dry Fork by the end of 2031. That level of CCS, if it can be achieved at all and in that time frame, can only be achieved with significant time and at great expense and risk. Indeed, Basin Electric is not aware of any manufacturer currently offering to warrant equipment that will achieve 90% CCS under *any* conditions, much less under large-scale and high-demand baseload conditions. Still, to have any hope of meeting the Final Rule's 2031 deadline for Dry Fork, Basin Electric must immediately begin spending money across a variety of expense categories.

20. *Carbon capture costs*. If it is possible to achieve 90% carbon capture at Dry Fork, it would require the addition of a post-combustion capture system. The cost for such a system is estimated to total approximately **$2 billion**. That astronomical expenditure is more than 150% of what it cost to construct the Dry Fork in the first place barely a decade ago. Complying with the Final Rule's 2031 deadline would require that Basin Electric enter into engineering, equipment, and other contracts immediately.

21. Basin Electric would first need to enter into engineering contracts, as a great deal of engineering would need to be performed prior to entering into any equipment contracts. Engineering costs typically represent approximately five percent of project costs, and are typically more costly for projects which involve the construction of new technology. In addition, Basin Electric would also need to hire an engineering firm to commence modeling work in order to apply for the permits necessary to begin construction of such a project.

22. The next step is ordering equipment. The carbon capture process equipment alone would cost Basin Electric approximately $400 million and a down payment of approximately 10% would likely be required. Engineering and equipment would need to be scheduled and committed to within the next 12 months. Based on previous experience, approximately 5 – 10% of the total project cost is spent on engineering and design costs. In the first two years alone, Basin Electric would expect to spend approximately $20 million on preliminary engineering and design costs that, but for the Final Rule, would not be expended.

23. *Carbon transport costs.* For CCS to work, once captured, the CO_2 must be transported to appropriate pore space. At Dry Fork, this would require approximately 27 miles of pipeline, based on preliminary studies. Some level of CCS would be feasible at Dry Fork (if at all) only because there is pore space in the region that could accommodate CO_2 storage. Still, constructing a pipeline to transport captured CO_2 from Dry Fork to this location would cost approximately $4 million per mile. Given high demand and long lead times for labor and specialized piping—both of which will only worsen as owners of EGUs across the country simultaneously attempt to comply with the Final Rule—Basin Electric must begin spending money immediately for planning, design, engineering, siting, permitting, and construction of a pipeline to transport captured CO_2.

24. Basin Electric's subsidiary, the Dakota Gasification Company, recently built a CO_2 pipeline. Based on that project, we estimate the required pipeline for Dry Fork would cost approximately $108 million and that Basin Electric would perform the engineering design and procure the equipment at a cost of approximately $50 million in the first two years.

25. *Carbon storage costs*. Once it is transported, the captured CO_2 from Dry Fork must be stored. Identifying and contracting for the necessary pore space is likely as challenging as meeting the 90% carbon capture requirement. Pore space in Wyoming will be challenging to procure, in light of the large percentage of federally owned land within the state. There is potentially suitable geology for CCS near Dry Fork, but geology is only the first piece of the puzzle. Even once transportation is solved, pore space can be utilized for storage only after an operator leases the thousands of acres of pore space and designs, permits, and constructs the storage facility. As with constructing a pipeline, all of that is outside Basin Electric's control. Leasing pore space for storage is both time-consuming and expensive.

26. *Operational costs*. According to a third-party study that Basin Electric commissioned several years ago, the annual operating and maintenance cost for 70% carbon capture at Dry Fork was estimated to be $56 million (2029). But even implementing that plan would not be sufficient to comply with the Final Rule, which would instead require Dry Fork to achieve a 90% CCS by January 1, 2032. Assuming 90% capture could be

achieved, that level of CCS would cost even more in annual operating expenses. The technology for attempting to achieve 90% CCS also demands significant water usage. Water is a scarce resource in Wyoming and would only be available at substantial expense. All of these are costs that Basin Electric must ultimately pass through to its consumer members.

27. *Reliability impacts.* One further significant cost is that CCS at any level tends to make an EGU less reliable. This makes unplanned outages more frequent and more severe. Basin Electric personnel have been to the Boundary Dam CCS project in Saskatchewan, and Basin Electric is familiar with the challenges experienced by SaskPower in maintaining and operating that capture unit, including unplanned outages. Unplanned outages increase Basin Electric's overall costs, hurt its relationships with consumer members, and can even affect its standing with the Regional Transmission Organization ("RTO"). Therefore, the reliability impacts of CCS are another significant risk facing Basin Electric.

28. *Impacts at Antelope Valley Station — "Medium Term" subcategory.* The Antelope Valley Station ("Antelope Valley") consists of two affected

EGUs located in Beulah, North Dakota. Each EGU is rated at 450 MW. Antelope Valley is located on a site adjacent to Dakota Gasification Company's Great Plains Synfuels Plant. Antelope Valley began operation in the 1980s, with a construction cost of approximately $1.9 billion. Antelope Valley is fueled by lignite coal from the adjacent Freedom Mine.

29. Antelope Valley's remaining depreciable life extends into the 2040s. Yet the Final Rule's default BSER—90% CCS by the end of 2031—is not economically feasible at Antelope Valley due to the age of the units and the short time that would be available to recover the massive investment necessary for CCS. Basin Electric has engaged in extensive efforts to participate in CCS research and development, including spending millions of dollars toward project development to build a demonstration project at Antelope Valley. That demonstration aimed to capture CO_2 emissions from about *one quarter* of *one* of the units at the plant. In other words, even this state-of-the-art demonstration project would not be sufficient to comply with the Final Rule. But even with a $100 million grant from the DOE and the availability of Dakota Gasification Company's pipeline for transporting the

captured CO_2, Basin Electric's feasibility study determined that the technology required too large of a parasitic load. Additionally, it came with an estimated cost of at least $500 million in 2010, would result in a significant increase in the cost of electricity to Basin Electric's members, and posed too great a risk given the technology provider was unwilling to guarantee the removal rate.

30. Due to these and other factors, Basin Electric plans to subcategorize Antelope Valley into the Final Rule's "medium term" subcategory. That election requires Basin Electric to make a legally binding commitment (in 2025 or 2026) to shut Antelope Valley down by 2038, and to achieve 40% natural gas co-firing at Antelope Valley by the end of 2029. To achieve that, Basin Electric must immediately begin spending money across a variety of expense categories.

31. *Equipment costs*. Retrofitting Antelope Valley's EGUs to co-fire 40% natural gas by the end of 2029 will require Basin Electric to make immediate capital expenditures. Antelope Valley uses natural gas as a startup fuel, but the existing equipment only allows for approximately 20%

co-firing. Because of that, each EGU's burner unit must be replaced, at an approximate total cost of $4 to 5 million. Burners are not "off the shelf" equipment, but instead must be purchased from a limited number of original equipment manufacturers, all of whom will simultaneously be facing a massive increase in demand from other affected EGUs across the country.

32. *Transport costs*. Basin Electric cannot co-fire natural gas at Antelope Valley unless there is a way for natural gas to be transported to those EGUs. Antelope Valley currently receives natural gas for startup fuel via a pipeline sourced from the Great Plains Synfuels Plant. However, to have an independent supply of natural gas would require installation of an approximately 40-mile pipeline connecting Antelope Valley to the closest interstate gas pipeline, Northern Border Pipeline, and related fuel supply infrastructure at cost of approximately $160 million (based on the assumption of $4 million per mile.) Given the long lead times for construction projects, a pipeline operator must begin design, permitting, siting, procurement, and construction immediately merely to have a chance to have natural gas available to Antelope Valley in time for the Final Rule's

end-of-2029 deadline. But no operator is likely to take all those steps without a substantial, up-front commitment from Basin Electric—either in the form of a capital contribution to the project, or in the form of a long-term (20-30 year) supply contract. Even if Basin Electric identified an operator and agreed to such terms, there is no guarantee that such a pipeline could actually be completed in time. Permitting, engineering construction, right-of-way acquisition, and myriad other factors could block the pipeline or could delay it beyond the Final Rule's compliance deadlines. If that happened, Basin Electric's investments in equipment costs would be completely lost, and Antelope Valley would need to shut down.

33. *Permitting risks*. Converting Antelope Valley to natural gas co-firing will also require Basin Electric to obtain new permits, including a New Source Review permit and an updated Title V permit. But these permits are expensive and time consuming, and their issuance is also subject to judicial review. In order to have proper permitting in place by 2030, Basin Electric must immediately begin the permitting process for Antelope Valley.

34. *Impacts at Leland Olds Station – Retirement under Applicability Exemption.* The Leland Olds Station ("Leland Olds") consists of two affected EGUs that together generate 660 MW in Stanton, North Dakota. Unit 1 was placed into service in 1966 and Unit 2 was placed into service in 1975. Leland Olds uses lignite coal delivered via rail from the Freedom Mine near Beulah, North Dakota. The remaining depreciable lives of the two Leland Olds units extend to 2030 and 2040, respectively.

35. The default compliance path—90% CCS by the end of 2031—is not economically feasible at Leland Olds given the age of these units and the short time that would be available to recover the massive investment necessary for CCS.

36. The medium-term compliance path—40% natural gas co-firing by 2030, and closure by 2040—also is not economically feasible at Leland Olds, given the age of the units and the cost to bring natural gas to Leland Olds. To connect to the closest interstate pipeline, the Northern Border Pipeline, would require the construction of an approximately 50-mile pipeline. Connecting Leland Olds to that pipeline would be prohibitively

expensive. And given the current regulatory environment, it is also highly unlikely that such a connection could be designed, sited, permitted, constructed and right-of-way acquired before the Final Rule's 2030 deadline. Furthermore, even with a firm supply of natural gas, co-firing natural gas at Leland Olds would require substantial investments in new equipment.

37. Because of those and other factors, Basin Electric has no choice but to commit (in 2025 or 2026) to retire Leland Olds by the end of 2031 to claim an applicability exemption under the Final Rule. That election requires Basin Electric to make a legally binding commitment to shut down Leland Olds by the end of 2031. This compliance pathway requires Basin Electric to immediately begin incurring expenses across a variety of expense categories.

38. *Transmission costs*. Whereas Leland Olds sits at a single site, replacement generation units would need to be dispersed over a broad area. That said, prior to doing any transmission planning, Basin Electric would first need to do the engineering studies to determine where it will place the generating units to replace the lost capacity from Leland Olds. This reality will require Basin Electric to make immediate and substantial investments

in these studies before it can even begin to plan for new transmission. A reasonable estimate of the cost of additional transmission lines is approximately $2 million per mile.

39. *Coal supply costs*. Basin Electric purchases coal for Leland Olds from the Freedom Mine (which also provides lignite coal to Basin Electric's Antelope Valley), and also from the Dakota Gasification Company's Great Plains Synfuels Plant. But if Leland Olds shuts down at the end of 2031, the cost of coal to Antelope Valley would increase significantly. That is because a substantial portion of the costs of mining are fixed costs. Losing a major purchaser in the next decade would result in the pass through of these fixed costs over a smaller number of tons. The mine will pass these costs on to Basin Electric in the form of higher prices for coal, and those increased costs will ultimately fall on Basin Electric's consumer-members.

40. *Impacts at Laramie River Station*. Basin Electric is a minority co-owner of the Laramie River Station ("Laramie River") located in Wheatland, Wyoming. Laramie River's three affected EGUs generate approximately

1,700 MW, of which Basin Electric owns about 42%, for a total of roughly 714 MW. Basin Electric is also the operator of Laramie River.

41. Decisions about compliance for Laramie River are not solely Basin Electric's to make. Instead, decisions are made by a majority of the station's owners. Decision-making about the compliance plan for Laramie River is still in process. Even so, and for many of the same reasons discussed above (and below) with regard to the other EGUs in Basin Electric's portfolio, each of the available compliance pathways under the Final Rule would require Basin Electric to immediately begin incurring substantial expenses—either in the form of new equipment (*e.g.*, CCS, natural gas supply, or co-firing equipment), replacement generation (if Laramie River retires by 2031), or both. If the owners of Laramie River chose to subcategorize the units into the medium-term subcategory, retrofitting the Laramie River EGUs to co-fire with natural gas would cost approximately the same as for each unit of Antelope Valley.

42. *Iowa Plants*. Basin Electric has entered into power purchase agreements with two of its members to purchase the output of capacity and

energy from their ownership interest in three coal-fired generating units in Iowa. Those three coal-fired generating units include George Neal South Generating Station South Unit 4 (Neal 4), Walter Scott Jr. Energy Center Unit 3 (Walter Scott 3), and Walter Scott Jr. Energy Center Unit 4 (Walter Scott 4), located near Sioux City, Iowa—all of which are operated by MidAmerican Energy Company. The power purchase agreements that Basin Electric has with its members provide Basin Electric with the responsibility to reimburse its members for approximately 16% of the costs of the unit. The remaining depreciable life of Neal 4 extends to 2040.

43. The Walter Scott units 3 and 4 are in Council Bluffs, Iowa. The power purchase agreement that Basin Electric has with its member provides Basin Electric with the responsibility to reimburse its member for approximately 4% of Walter Scott 3 and 6% of Walter Scott 4. The remaining depreciable lives of Walter Scott 3 and 4 extend to the late 2030s and 2060s, respectively.

44. Since Basin Electric's members do not own the entire units and their ownership interests are relatively small, they do not have the ability to

make the decision on the compliance strategy that these units would pursue. Each of these units is operated by MidAmerican Energy Company, which also has the largest ownership interest in each unit. Depending on the compliance strategy that would be selected for each of the units, there is the possibility that Basin Electric may have to look for replacement power alternatives to replace any lost power due to compliance with the Final Rule.

IV. REPLACEMENT POWER

45. *Dry Fork*. Even if 90% CCS could be achieved at Dry Fork, actually running the technology requires substantial amounts of power. This dynamic creates what is referred to as a "parasitic load," that is, the CCS system drains or otherwise consumes a portion of the electrical energy generated by its host EGU. At Dry Fork, the **parasitic load for CCS is estimated to be about 25%** of the EGU's total capacity. This means that about 100 MW out of Dry Fork's 405 MW of capacity would be redirected from Basin Electric's members in order to support CCS at Dry Fork. As a result, Basin Electric must replace that power in order to continue to meet

member demand. This will require either buying new power from the market or building 100 MW of new generation.

46. But if the Final Rule takes effect, electric markets will be highly constrained, as generators across the country will see reductions in their portfolios. Thus, the most cost-efficient option to address the parasitic load of CCS is to build new generation to offset the 100 MW loss at Dry Fork. Yet the Final Rule also imposes stringent requirements for new base load gas-fired combustion turbine EGUs—all of which must achieve 90% CCS. That level of CCS is not possible for new EGUs, which would be composed of natural-gas units rather than coal-fired units. Nor can Basin Electric depend on renewables for baseload generation.

47. Thus, for new generation to offset the parasitic load of CCS at affected EGUs, Basin Electric's options include building (1) a large number of low-capacity combustion turbines ("CTs") all running at a capacity factor of 20% or less; (2) reciprocating internal combustion engines; or (3) combined cycle generation with its capacity factor limited by its efficiency. All three of these options are expensive and inefficient. As an example, to achieve 100

MW of reliable baseload generation, Basin Electric would need to build 600-700 MW worth of CTs (the extra MW being necessary to satisfy the applicable RTO reserve-margin requirements). For that generation to offset the 100 MW loss at Dry Fork to be available by 2030, Basin Electric must begin spending money now for engineering, planning, design, siting, permitting, fuel procurement, and construction.

48. *Leland Olds*. Retiring Leland Olds by 2031 would reduce the energy available from Leland Olds to provide energy to Basin Electric's consumer members. In aggregate, this retirement reduces Basin Electric's resource portfolio by 660 MW. Basin Electric would need to replace the lost energy from the units. Basin Electric must replace that capacity to ensure that its members receive reliable and affordable electric service.

49. Basin Electric cannot turn to the market for that amount of generation. Instead, it must construct new generation. Conservatively, replacing that level of generation will cost approximately $3 billion (based on an assumed cost of $4,400 per kW). All of these costs will be exacerbated by the fact that the Final Rule does not allow for new baseload EGUs unless

they can achieve 90% CCS, which has not been demonstrated. To ensure that adequate new generation is available by the time Leland Olds is forced to shut down completely at the end of 2031, Basin Electric must begin making capital expenditures now.

50. *Laramie River and Iowa Units.* Depending on the election taken by the owners of Laramie River, Basin Electric would be looking at replacing 714 MW of its entitlement at Laramie River in either 2031 or 2038. Similarly, depending on how the owners of the units in Iowa choose to comply, Basin Electric would need to replace 200 to 210 MW in either 2031 or 2038.

V. CUMULATIVE IMPACT OF THE FINAL RULE ON BASIN ELECTRIC

51. Basin Electric operates the largest G&T cooperative fleet of affected EGUs, relies on that fleet to produce the highest amount of MWs, and distributes that energy across the largest G&T footprint in the Nation. Meanwhile, Basin Electric's current load forecast projects that Basin Electric's load is expected to grow at more than 4% annually over the next ten years, which amounts to an increase of more than 2,000 MW during this decade. This significant load growth is due to a combination of residential,

agricultural, commercial, and industrial development, including facilities to be constructed with funding and tax incentives under the Inflation Reduction Act. The Final Rule has an inordinate impact on Basin Electric.

52. By 2035, complying with the Final Rule will require nearly $10 billion in incremental capital expenditures, nearly doubling Basin Electric's current asset base. Complying with the Final Rule will also increase the Operating & Maintenance expenditures where new systems and equipment are added. Those expenses will fall on members, who already expect to see rate increases associated with load growth. Additional expenses resulting from the Final Rule will result in a rate increase of approximately 60% for members by 2035. At the same time, the capital expenditures spent to comply with the Final Rule (in addition to previously planned capital expenditures for member load growth) will increase the amount and costs of Basin Electric's borrowing, and will negatively affect Basin Electric's capitalization and coverage ratios. Additionally, the rating agencies will likely view the substantial increase in debt, operational execution challenges of complying with the Final Rule, and significant reliance on unproven technology as

negative credit factors in their assessment of Basin Electric's credit. All these impacts would likely have a negative impact on Basin Electric's bond ratings, which would further compound the challenge of obtaining sufficient capital at a reasonable cost to comply with the Final Rule.

53. Basin Electric and other G&T cooperatives enter into long term "all requirements" contracts with their member-owners. Basin Electric's "all requirements" contracts require Basin Electric to meet all of the members' electricity demand for the duration of the agreements (which run through 2050 or 2075).

54. By forcing EGUs to retire early, the Final Rule seriously threatens Basin Electric's ability to meet its contractual commitments to supply "all requirements" to its members. Forced retirements will also make it more difficult for Basin Electric to satisfy the planning reserve margins that the RTO, Southwest Power Pool ("SPP"), and Midcontinent Independent System Operator ("MISO") require. These margins are the magnitude of incremental accredited capacity that Basin Electric must have available to meet unexpected increases in demand, or to cover for capacity that might be

unavailable due to maintenance or unexpected outages. In other words, the planning reserve margin is a percentage that represents the amount of available capacity over and above the expected peak demand. Forced retirement of baseload EGUs makes it more difficult for Basin Electric to comply with the RTOs' current planning reserve margins requirements. In addition, these planning reserve margins have also been increasing to offset the intermittency that is inherent in renewable resources such as wind and solar, which have greatly increased as a percentage of the RTO resource mix in the last decade. This is further exacerbated as renewables continue to grow and displace dispatchable generation facilities that have retired, will retire in the future, or could be limited in their operation in the future.

55. Thus, at the same time that planning reserve margin requirements and demand are steadily *increasing*, the Final Rule's forced EGU retirements are drastically *decreasing* the amount of available baseload dispatchable generation.

56. Systematic premature retirement of baseload EGUs increases the likelihood of blackouts and other reliability failures, like those experienced

in Texas during Winter Storm Uri in February 2021. Replacing the baseload power from EGUs is challenging, expensive, and time-consuming. Current supply-chain delays, the limited number of available suppliers, labor-market shortages, and the limited capacity of the capital markets will only worsen as utilities across the Nation simultaneously rush to construct replacement EGUs. In other words, the Final Rule causes significant short- and long-term harm to both Basin Electric and the electric utility industry as a whole.

VI. ABSENT A STAY, BASIN ELECTRIC WILL SUFFER IMMEDIATE IRREPARABLE HARM

57. Basin Electric has made significant expenditures for resource planning, technology evaluations, and CCS research and design studies. As a result of these studies, Basin Electric has put itself in a position to understand the cost, timing, and scope of the effort necessary to comply with the Final Rule.

58. An interconnection study is a meticulous process that can span several years, with recent requests taking up to 7 years to complete. Currently, the SPP generation interconnection queue contains over 400 active requests, some of which are over 6 years old without a final

Generation Interconnection Agreement. This delay prevents interconnection customers from knowing the total required interconnection costs necessary to make informed decisions about proceeding with the construction of generation.

59. Despite efforts by SPP and other RTOs to address the backlog of their interconnection queues, these numbers are expected to rise due to the influx of new requests prompted by the Final Rule. Consequently, Basin Electric must conduct studies to strategically plan the location of replacement generation and promptly submit interconnect requests to meet compliance deadlines. Even if utilities were able to promptly put in numerous interconnection requests, delays in the current interconnection processes would prevent utilities from making an informed, prudent decision to proceed. Accordingly, Basin Electric must first perform the studies necessary to plan the location of a large number of generating units and then act quickly to submit new interconnect requests in order to stand any chance of meeting the Final Rule's compliance deadlines.

60. At the same time that the Final Rule is forcing Basin Electric to rush to secure replacement power, RTO planning reserve margin requirements and the resource adequacy rules are changing to *increase* the amount of accredited capacity that Basin Electric must maintain as a market participant and load responsible entity. These requirements only pile on top of the other delays and expense factors previously discussed, and only increase the need for Basin Electric to take immediate action to comply with the Final Rule.

61. The National Environmental Policy Act ("NEPA") requires lengthy and highly detailed environmental reviews for projects that take place on federal land, receive federal funding, or require federal permitting or other approvals. Depending on the significance of the potential environmental impacts involved, an environmental impact statement or environmental assessment may be required. A federal agency's NEPA compliance is also subject to judicial review. Nearly half of Wyoming sits on federal land. This fact alone adds (at minimum) several years to many of the new Wyoming construction projects discussed above—whether siting for

replacement generation, transmission lines, pipelines to transport carbon, or pore space to store carbon in the state of Wyoming. The Final Rule requires Basin Electric to construct or rely on the construction of multiple new projects at or around multiple affected EGUs which may require compliance with NEPA. NEPA reviews (and potential related litigation) can literally add years to the construction process for these projects, and must be completed before work on a project may proceed. This only increases the need for Basin Electric to take immediate action.

62. *Section 106 delays*. Compliance with Section 106 of the National Historic Preservation Act—accounting for effects on historic properties—is also required for any projects that are carried out with federal financial assistance or requiring a federal permit, license, or approval. In other words, any project that triggers NEPA is also likely to trigger Section 106 review. Yet Section 106 determinations are also subject to judicial review, which can be lengthy and expensive, further illustrating the need for Basin Electric to take immediate action.

63. *Immediate engineering costs*. Attempting 90% CCS (at Dry Fork) by 2031 and 40% natural gas co-firing (at Antelope Valley) by 2029 would require Basin Electric to immediately begin with engineering studies, design studies, modeling studies, and permitting activities. All of that must happen soon, because each increment of delay puts compliance with the Final Rule even further out of reach. Multi-year engineering work would need to be performed prior to ordering any equipment. Equipment deliveries would likely follow placement of the orders by several years. Once the equipment is purchased and received, it must be installed and tested as part of the overall construction of the project. Then Basin Electric must troubleshoot to ensure that the equipment is operating efficiently and reliably.

64. Working backwards from the Final Rule's compliance dates, the engineering **should have already begun**. Indeed, when Basin Electric executed a Selective Catalytic Reduction ("SCR") project for Laramie River, the overall process took five years—and that was for a mature technology that is orders of magnitude simpler than CCS or conversion to co-firing, and that did not require new pipelines or underground storage.

65. Pipeline transportation is necessary for both CCS (CO_2) and co-firing (natural gas). Again, engineering studies and pipeline routing need to be undertaken immediately. Pipelines require state and federal permits. Landowner fatigue, increasing community resistance to pipelines, and difficulties in securing pore space for CO_2 storage and right-of-way for CO_2 pipelines have the potential to add significant time and cost to these new construction projects. And because these projects will require obtaining permits for novel components Basin Electric has not previously attempted (*e.g.*, pore space, transport for CO_2), projections must build in extra time. Basin Electric must immediately begin making expenditures in order to help bring these resources into existence in time for the Final Rule's compliance deadlines.

66. *Replacement power costs*. Basin Electric will need to **replace approximately 2,600 MW of baseload**, dispatchable generation significantly earlier than planned as a result of the Final Rule. Renewable energy sources (such as wind and solar) cannot satisfy that demand. Land acquisitions alone would be cost-prohibitive. But even ignoring that, renewables are an

intermittent resource that are available only *some* of the time. Thus, for replacement power, Basin Electric must turn to natural gas. But even today's state-of-the-art natural gas combined cycle units ("NGCCs") cannot achieve the 90% CCS that the Final Rule demands. Even if those units could achieve 90% CCS, constructing them would cost approximately **$11.4 billion** as compared to Basin Electric's current asset base of $8 billion. That estimate does not include land, water rights, financing fees, escalation, tax, or insurance. This estimate also does not include the significant costs for new transmission buildout and fuel transportation that would be associated with new units. In order to bring that amount of generation into its portfolio by the Final Rule's deadlines, Basin Electric has no time to spare. Instead, it must immediately begin the engineering work to construct replacement generation—whether NGCCs, CTs, renewables, or some combination thereof.

67. Even if Basin Electric could secure the vast amount of replacement power that is required due to the Final Rule's forced retirements and other requirements, that power is useless unless it can be effectively

transmitted to members. But much of the replacement power that Basin Electric must build will be in the form of distributed generation. For a variety of reasons—including cost, efficiency, and decommissioning work—these types of natural gas generation facilities would need to be sited at new locations near interstate natural gas pipelines and high voltage transmission lines (not at the old locations of the coal-fired EGUs that the Final Rule forces to retire). Because of that, Basin Electric will also need to immediately begin to determine the locations of new generation so that generation interconnection requests can be submitted to the RTOs.

68. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of NRECA's Petition for Review. Basin Electric expects that process to take *at least* 2 to 3 years. But the Final Rule's compliance deadlines do not give Basin Electric any time to spare. For one thing, the Final Rule's one-year compliance extension mechanism is available only if Basin Electric "has made all reasonable efforts to achieve timely compliance" and "has acted consistent with achieving timely compliance." 89 Fed. Reg. 607. In other words, Basin Electric must act

now in order to preserve its ability to claim the Final Rule's compliance extension mechanism (if it is even added to the State plans that will govern Basin Electric). For numerous other reasons, too, haste is of the essence.

69. Complying with the Final Rule will require Basin Electric to hire numerous consultants, engineers, attorneys, and other professionals to manage the vast amounts of design, modeling, permitting, and other work required under the Final Rule. Yet these markets too are subject to the laws of supply and demand. As EGU owners across the Nation rush to hire the same professionals, availability will decrease, and prices will increase. Accordingly, EGU owners must move early—not only to insulate themselves from price pressures, but also in attempt to ensure that the needed professionals are even available.

70. Bringing replacement power online is a costly and time-consuming process. Initially, Basin Electric and other load-serving entities must submit an interconnection request to the appropriate RTO, such as SPP or MISO, depending on whose transmission facilities the generation facility will connect to. This request requires crucial details such as proposed

location, size, fuel type, prime mover description, intended commercial operation date, and point of interconnection specifications (substation name, line voltage), applicable study deposits, required financial security deposits, and evidence of site control or additional financial security. Once received, the RTO conducts an analysis to assess the impact of the new generation on the network. All of this takes large amounts of time and money.

71. *Immediate costs to Basin Electric.* All of the previously described costs are costs which Basin Electric would not incur but for the Final Rule. If Basin Electric begins incurring these costs as a result of the Final Rule and the Final Rule is ultimately overturned by the courts, these costs are sunk and cannot be recaptured. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded.

72. Without question, the greatest irreparable harm to Basin Electric and other members of the electric utility industry is the fact that we will be forced to make legally binding obligations to close power plants while the Final Rule is being litigated. Those kinds of retirement obligations would not otherwise arise for years or decades to come.

*   *   *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 10th day of May 2024, in Bismarck, ND.

Gavin A. McCollam

Appendix 6

DECLARATION OF JERRY PURVIS

I, Jerry Purvis, declare as follows:

1. My name is Jerry Purvis. I am the Vice President of Environmental Affairs at East Kentucky Power Cooperative ("East Kentucky"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have 30 years of experience in electricity generation. I have been employed at East Kentucky since 1994. I hold a bachelor's degree in Chemistry from Morehead State University and a bachelor's degree in Chemical Engineering from the University of Kentucky. I have a Masters of Business Administration from Morehead State University. As Vice President, I am responsible for promoting proactive environmental policies, implementing comprehensive compliance strategies, and supporting East Kentucky's sustainability goals. I manage East Kentucky's staff and outside consultants in pursuit of these goals.

3. East Kentucky is a member of the National Rural Electric Cooperative Association. This declaration is submitted in support of the legal challenges to EPA's final 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," 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule"). I am familiar with East Kentucky's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect East Kentucky as well as its suppliers, members, customers, and employees.

4. East Kentucky is a not-for-profit that is owned, operated, and governed by its members, who use the energy and services East Kentucky provides. These owner-member cooperatives provide energy to 520,000 homes, farms, and businesses across 87 counties in Kentucky. East Kentucky's purpose is to generate electricity and transmit it to 16 Owner-

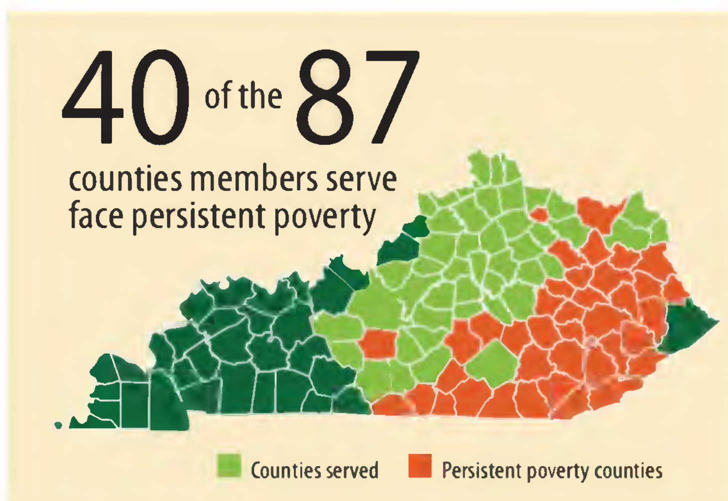
Member cooperatives that distribute it to retail, end-use consumers ("Owner-Members"). East Kentucky provides wholesale energy and services to Owner-Member distribution cooperatives through baseload units, peaking units, hydroelectric power, solar panels, landfill gas to energy units and distributed generation resource power purchases – transmitting power across the rural Kentucky areas via more than 2,900 miles of transmission lines. East Kentucky's Owner-Members' collective customer base is comprised largely of residential customers (93%). And, in 2019, 57% of East Kentucky's owner-member retail sales were to the residential class. Electricity is the primary method for water heating and home heating for this class of customers.

5. East Kentucky is a member of PJM Interconnection ("PJM"). PJM is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in 13 states and the District of Columbia.

6. Demand for electricity is increasing in Kentucky. East Kentucky predicts increased demand during the time span in which this Final Rule would impact. East Kentucky forecasts net total energy requirements to

increase from 13.5 to 16.7 million MWh ("megawatt hours"), an average of 1.5 percent per year over the 2021 through 2035 period.[1] Residential sales will increase by 0.7 percent per year, and small commercial sales (customers with ≤1000 KVA ("kilo-volt-amperes")) will increase by 0.9 percent per year. The greatest area of growth will be for large commercial and industrial sales (customers with >1000 KVA), projected to increase by 3.3 percent per year.

7. East Kentucky is the voice for a substantial number of end users of electricity in its service territory that live in impoverished communities. These communities place a high value on affordable energy costs. East Kentucky's service territory includes rural areas with some of the lowest economic demographics in the United States. In these



[1] East Kentucky Integrated Resource Plan, Load forecast 2021-2035, December 2020 (IRP 2020).

areas, families are literally faced with a daily choice between food, electricity, and medicine. Of the 87 counties that East Kentucky's Owner-Member cooperatives serve, 40 counties experience persistent poverty, as reported by the USDA.

8. Many of these hardworking Americans have been plagued by unemployment from mines, trucking companies, restaurants and other businesses. The unemployment rate is 60% higher than the national average. They rely on government assistance to survive; anywhere from 30% to 54% of total income in most of the counties that East Kentucky serves comes from governmental assistance programs. Forty-two percent of these electricity users are elderly (65 years or older). Many are on fixed incomes and reside in energy-leaking mobile homes. Recent brutal cold weather has caused their monthly electric bills to skyrocket. East Kentucky has a strong interest in keeping energy affordable to assist its 16 Owner-Member cooperatives in serving people facing the harsh realities of today's economy.

EAST KENTUCKY'S ENVIRONMENTAL COMMITMENTS

9. East Kentucky and its Owner-Member cooperatives have a strong commitment to environmental excellence, which is underscored by a record of environmental over-compliance, investments in air control technology, waste water treatment, closure of ash ponds by removal, and managing waste dry and renewable diversification. East Kentucky has ensured that its efforts sustain excellent air quality, clean water, and properly disposed waste in accordance with and beyond regulatory minimums. East Kentucky is a leader in environmental stewardship in the Kentucky community. Kentucky Energy and Environmental Cabinet awarded East Kentucky its Beacon Award, the highest Environmental Stewardship award in Kentucky in 2023. In addition, East Kentucky has created a Strategic Sustainability Plan with goals and investments through 2035 and 2050. East Kentucky developed, permitted and built the first renewable energy sources in Kentucky. Since that time, East Kentucky launched a 60-acre photovoltaic solar array in Winchester, Kentucky, and East Kentucky continues to utilize landfill gas generation assets and to support hydroelectricity (Wolf Creek and Laurel Dams) via Southeastern

Power Administration ("SEPA") contracts. East Kentucky also just announced plans to construct an additional 136 MWs of solar capacity.

10. East Kentucky owns electric generating units ("affected EGUs") that fall within the Final Rule's scope of coverage and thus must comply with the Final Rule's stringent new standards for coal-fired steam units. These affected EGUs have remaining useful lives that will be significantly curtailed under the Final Rule—all at substantial cost to East Kentucky, and ultimately, to the rural ratepayers who are in East Kentucky's service area.

11. East Kentucky has one of the cleanest, best environmentally-controlled fleets in the country. East Kentucky's company-wide commitment to environmental excellence extends to compliance and a financial commitment to pollution control improvements at its generation facilities. East Kentucky and its 16 Owner-Member cooperatives **have invested over $1.8 billion** to reduce environmental impacts at its fossil generation facilities. Specifically, East Kentucky installed Best Available Control Technology ("BACT") level technology to control NOx, SO_2, and particulate matter (PM) emissions at its Spurlock and Cooper Plants. Those efforts extend to

significantly **lower SO_2 (95%), NOx (78%), PM (over 98%), and CO_2 (5.5%)** since 2005. Since 2008, East Kentucky has devoted substantial resources to ensure compliance with EPA final rules including the stringent Mercury and Air Toxics ("MATS") requirements. In fact, many of the units in its coal-fired fleet have qualified for low emitting EGU ("LEE") status. East Kentucky prides itself for installing state-of-the art emissions controls at its generation systems.

12. East Kentucky is an active participant in reducing its CO_2 footprint but recognizes that renewables must be balanced with coal-fired and dual-fueled natural gas-fired generation. East Kentucky installed 60 acres or 10 gross MWs of solar array commissioned in 2017 to begin to understand how renewables function within our system as a cleaner energy resource as our country transitions to cleaner resources. Yet, recent summer heat waves and winter freezes serve as stark evidence that renewable generation has operability and reliability constraints and is not always available to be dispatched when needed. Moreover, energy storage has not yet reached the point where it is able to completely fill the gaps in coverage

from renewable resources. Natural gas pipeline failures during Winter Storm Elliott also highlight the dangers of becoming too reliant on any single fuel source. Natural gas is delivered on a "just in time" basis, whereas coal is generally stockpiled so that many days or weeks of fuel is available to guard against unforeseen circumstances. Fossil-fuel generation plays an essential and undeniable role in grid reliability until technology advances.

OVERVIEW OF THE FINAL RULE

13. The Final Rule establishes CO_2 emissions limits that States must apply to existing coal-fired units, under Section 111(d). 89 Fed. Reg. at 39840. It also establishes limits for CO_2 emissions from new gas-fired combustion turbines, under Section 111(b). *Id.* at 39902. Under these limits, both existing coal-fired units and new gas-fired combustion turbine units must meet a stringent "presumptive standard of performance." *Id.* at 39836; *see id.* at 39823-24. That standard is the degree of emission reduction achievable by the application of 90% carbon capture and sequestration/storage ("CCS"). *See id.* 39801-02. Existing coal-fired units that do not deploy CCS must shut down (unless a State or federal regulator successfully invokes one of the

Rule's complex and discretionary exceptions). New units that do not reduce emissions to meet the presumptive standard must drastically reduce their output of electricity.

14. The Rule divides existing coal-fired units into three non-overlapping subsets: two "subcategories" and one "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit makes a federally enforceable commitment to retire, and by the date of that retirement. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *See id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

15. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can

permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

16. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent "—*i.e.*, transforming a coal unit into one that combusts both coal *and* natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

17. Third, units that make a federally enforceable commitment to permanently cease operating by January 1, 2032 have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id*. at 39991.

18. EPA deferred finalizing emissions guidelines for existing natural gas combustion turbines. The Final Rule does not address these units; rather, EPA has chosen to defer action to a separate, future rulemaking. Regardless, sources must immediately conduct resource-planning analyses to inform State plan elections. Without the benefit of a complete compliance landscape, these analyses will be challenging and create more uncertainty for the use of existing simple-cycle combustion turbines with regards to power supply planning.

19. For new and modified gas-fired combustion turbines, the Rule creates three subcategories, which are "based on electric sales (*i.e.*, utilization) relative to the combustion turbines' potential electric output to an electric distribution network." *Id.* at 39908.

20. "Low load" units are those that supply 20 percent or less of their potential electric output as net-electric sales. *Id.* at 39917. They must use lower-emitting fuels. *Id.* "Intermediate load" units are those that supply more than 20% but less than or equal to 40% of their potential electric output as net-electric sales. *Id.* These units must use highly efficient simple-cycle

turbine generation technology. *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO_2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

EAST KENTUCKY'S DISPATCHABLE COAL-FIRED ASSETS

21. Spurlock Station, East Kentucky's flagship plant, is located near Maysville, Kentucky on the Ohio River. All four units at Spurlock have state-of-the-art NOx, SO_2, PM, and Hg controls. In addition, East Kentucky has made substantial investments, to the tune of $262.4 million dollars, including a conversion to dry bottom ash, ash pond clean closure by removal, and new waste water treatment system with evaporation to ensure the plant is fully compliant with Effluent Limitation Guidelines ("ELGs") and the 2015 Coal Combustion Residuals ("CCR") rule. Spurlock is located adjacent to an International Paper corrugated packaging plant to which it is contractually-

committed to provide co-generation steam. The closest natural gas transmission pipeline is over 40 miles from Spurlock Station. The affected EGUs at the facility are:

- Unit 1 – is a wall-fired unit (344 MW) pulverized coal-fired boiler that combusts bituminous coal. Unit 1 has cold side ESP, WFGD, Wet ESP, SCR and low-NOx burners to control particulate matter (PM), SO2, SO3 / H2SO4 mist, and NOx respectively, installed on or before April 2009.
- Unit 2 – is a tangential-fired unit (555 MW) pulverized coal-fired boiler that combusts bituminous coal. Unit 2 has a hot side ESP, WFGD, Wet ESP, SCR, low-NOx burners, and over-fire air to control PM, SO2, SO3 / H2SO4 mist, and NOx, respectively, installed on or before 2008.
- Unit 3 – is a coal-fired circulating fluidized bed boiler ("CFB") unit (305 MW), which is designed to emit less NOx and SO_2 in the combustion process. Unit 3 has a SNCR to control NOx, a dry FGD to control SO2/SO3, and a filter fabric baghouse to control PM.

- Unit 4 – is a CFB unit (315 MW), which is designed to emit less NOx and SOx in the combustion process. Unit 4 has a SNCR to control NOx, a dry FGD to control SO2/SO3 and a filter fabric baghouse to control PM.

22. Cooper Station is located near Burnside, Kentucky adjacent to Lake Cumberland. Cooper Station is a critical generation asset due to its location in rural, south-central Kentucky that serves a transmission-constrained area. East Kentucky undertook significant control enhancements in 2013–2016, installing a pulse-jet fabric filter (baghouse) to control PM and dry FGD to control SO_2 in both units, and a SCR on Unit 2 to control NOx. The closest natural gas transmission pipeline is approximately 40 miles from Cooper Station. The affected EGUs at the facility are:

- Cooper Unit 1 – is a wall-fired unit (116 MW) pulverized coal-fired boiler that combusts bituminous coal. Unit 1 has low-NOx burners. It is tied into the Unit 2 dry FGD and pulse jet fabric filter to control SO_2 and PM and shares a common stack with Cooper Unit 2.

- Cooper Unit 2 – is a wall-fired unit (225 MW) pulverized coal-fired boiler that combusts bituminous coal. Unit 2 has a SCR and low-NOx burners, dry FGD and filter fabric baghouse to control PM and SO_2/SO_3. It shares a common stack with Cooper Unit 1.

23. The remaining depreciable life of Cooper Station and Spurlock Station extends past 2045 due to debt associated with the addition of environmental controls.

IMPACT OF THE FINAL RULE ON EAST KENTUCKY

24. East Kentucky relies on affected EGUs for more than 50% capacity of its current generation needs. Accordingly, the Final Rule will have a substantial impact on every aspect of East Kentucky's operations. These impacts will ultimately fall most heavily on rural Kentucky ratepayers.

I. Impacts of Carbon Capture and Storage as BSER

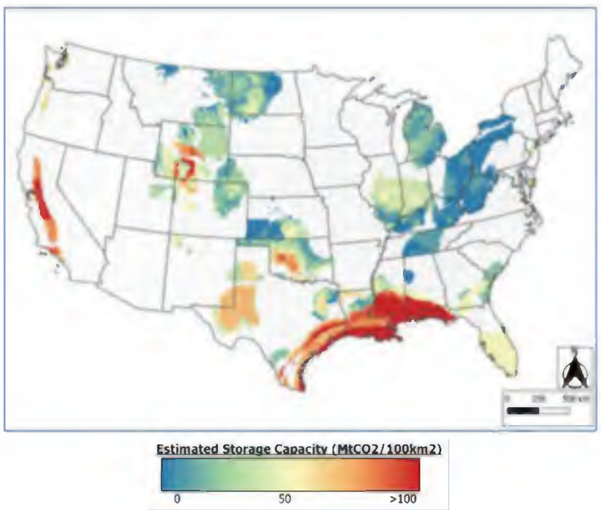
25. CCS is impracticable and infeasible at Spurlock or Cooper. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if

they can achieve 90% capture of carbon using CCS by 2032. But this is impossible at Spurlock and Cooper for the following reasons.

26. The technology to reliably achieve 90% capture of CO_2 using CCS is not commercially demonstrated or readily available. Even the emerging technology that is available is unreliable, not technology ready at the levels necessary to comply with the Final Rule and prohibitively expensive. CCS is potentially feasible, but it has not been adequately demonstrated. To be adequately demonstrated, CCS must be possible at all sites with existing coal-fired units, at all boiler-types, and at all loads. CCS has not been proven, even as a pre-demonstration project, at the size needed to treat the flue gas of a large coal-fired EGU such as those in the East Kentucky fleet. Technological issues are not the only thing preventing Spurlock and Cooper from relying on the CCS compliance pathway.

27. Even if 90% of the CO_2 could be captured, it would need to be transported for storage. For East Kentucky's plants, no CO_2 sequestration site or injection wells reside nearby. The Kentucky Society of Geologists and the University of Kentucky conducted testing at Hancock County, Kentucky

in 2009-2012 to sequester 1,500 tons of carbon dioxide.[2] After tests of sequestering 323 tons, officials reported that it would take 350 acres or more of land per well, which presented an "obstacle," and that "parasitic load of 25-30 percent" would occur. Future projects need to be at or below 10 percent parasitic load to be viable. The geology in Kentucky does not support storage of carbon at utility-grade levels with the required acreage, the lack of Kentucky regulations to mitigate risk to the sequestering company, and high degrees of parasitic load. In fact, Cooper Station is located in an area of karst terrain. The Electric Power Research Institute ("EPRI") conducted a study of locations in the United States suitable for carbon storage. Kentucky is generally identified in blue as an area with limited carbon storage potential. This means that an unworkable



[2] Topical Report: Summary of Carbon Storage Project Public Information Meeting and Open House, Hawesville, Kentucky, October 28, 2010, Report No. DOE/FE0002068 (June 25, 2012) ("DOE Carbon Storage Report").

amount of space would be needed to store enough CO_2 from a utility unit, not to mention CO_2 storage from an entire fleet.

28. To purchase the underground pore space to secure sufficient storage space is likely impossible – no such market actively exists – but certainly would cost more than East Kentucky's balance sheet.

29. No pipeline exists to carry captured CO_2 from Spurlock or Cooper to a storage location. The nearest areas with favorable geology in which CO_2 can be stored, according to EPRI,[3] would be in Illinois at a distance of 350 miles from Spurlock. Any such pipeline would need to cross miles of terrain at significant expense, or ***$10.7 million per mile of pipeline***.[4] ***To lay 350 miles of line would total over $3.7 billion*** – which is roughly equivalent East Kentucky's entire net book value today.

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[3] EPRI, Geospatial Modeling of Geologic Carbon Dioxide Storage Potential (June 30, 2023).

[4] Smith, "Land pipeline construction costs hit record $10.7 million/mile Oil and Gas Journal (Oct. 2, 2023), https://www.ogj.com/pipelines-transportation/pipelines/article/14299952/land-pipeline-construction-costs-hit-record-107-million-mile

30. Setting aside the self-evidently prohibitive costs that such a pipeline would entail, the evaluation, permitting, siting, design, and construction would all take much longer than the 7 years between now and the compliance date required by the Final Rule.[5] The pipeline could not, and would not, be operational before 2032.

31. Safety considerations should not be brushed aside. Although pipelines are regulated by the Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA,") oversight of pipelines cannot completely ameliorate the inherent risks from failures, as was illustrated by the CO_2 pipeline failure in Satartia, Mississippi. Accordingly, CCS is not an option for Spurlock and Cooper because there exists no readily available infrastructure to store or transport the captured CO_2.

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[5] Gas pipelines have experienced substantial delays due to legal and compliance issues. World Pipelines, "Court rulings, delays and cancellations underscore challenges for gas pipeline construction" (July 15, 2021). CO2 pipelines are expected to encounter similar delays.

32. CCS Projects are prohibitively expensive due to development, one-time capital costs, and ongoing operating costs. Project Tundra, a large-scale CCS project in Center, North Dakota, is estimated at a cost of over $1.6 billion to construct. It is designed to treat 530 MW of flue gas, which is the largest scale project of its kind in North America. The scale of Project Tundra – which involves injection into an adjacent underground storage facility – would not be large enough to cover the flue gas from Spurlock Unit 2 (555 MW) and certainly not the 1,519 MW gross that the Spurlock units collectively generate.

33. Using Project Tundra as a model, for each of the Spurlock units, East Kentucky calculated the capital cost of installing CCS, the carrying cost of the loan required for the project, and the ongoing operation costs of CCS.

34. The following Table A illustrates these costs based on publicly-available information for Project Tundra. The CCS capital project on its own would cost $6.2 billion dollars for all four Spurlock units, which would need to be financed. Finally, estimated operational costs of CCS equipment would total $17.74 per megawatt hour annually. The cost of storing the captured

CO_2 adds another $2.2 billion, which would have to be transported to Illinois as the closest feasible storage location at a cost of over $3.7 billion. The grand total is $10.7 billion, collectively. Even this analysis does not fully take into account the cost of the parasitic nature of CCS load. To keep existing EGUs in operation, the Final Rule will create an absurd and unintended consequence of stimulating the construction of generation assets to replace the megawatts lost to operate CCS systems.[6]

Table A – CCS Capital Investment and Operational Costs, Separately

Capital Investment				45Q Tax Credit	Cost per MWH		
Capital Cost CCUS	Capital Cost Transportation	Capital Cost Storage	Capital Investment Total	45Q Tax Credit ($/ton)	45Q Credit	Total	Total 45Q
$1,352,093,023	$816,497,093	$165,599,834	$2,334,189,950	$ 77.11	$75.52	$202.85	$127.33
$2,433,767,442	$1,469,694,767	$298,079,701	$4,201,541,910	$ 77.11	$75.45	$202.83	$127.38
$1,207,869,767	$729,404,070	$147,935,851	$2,085,209,689	$ 77.11	$68.31	$201.10	$132.79
$1,207,869,767	$729,404,070	$147,935,851	$2,085,209,689	$ 77.11	$71.43	$201.86	$130.43
$6,201,600,000	**$3,745,000,000**	**$759,551,237**	**$10,706,151,237**	$ 77.11	$73.29	**$202.31**	**$129.02**

35. Table A provides the capital investment total, which is the cost to construct the CCS project ($10,706,151,237.00) in the orange shaded area.

[6] DOE Carbon Storage Report (reflecting 25-30% losses to operate the CCS system).

The green area identifies the IRC 45Q tax credit that CCS facilities may receive in dollars per ton ($77.11/ton). Finally, in the tan area, East Kentucky calculates the cost per megawatt hour to include the operational costs of running the CCS system on an annual basis ($202.31), which reduces to $129.02 per megawatt hour after applying $73.29 of benefits from 45Q tax credits. The 45Q tax credits marginally reduce the annual costs, but the credits hardly place a dent in the overwhelming expense of operating CCS. Table A's cost per megawatt hour ($129.02) *does not include* the costs to build the project ($10,706,151,237.00). Table B, below, cumulates these costs.

Table B – CCS Annual Capital Investment and Operational Costs, Cumulative Total including 45Q Benefits

Annual Costs for Spurlock Station CCS		5/8/2024
Spurlock CCS Operational Costs w/45Q	Cost CO2 (45Q)	Operational Annual
MWh	$/MWh	$/year
10,245,696	129.0168251	$ 1,321,867,168.52
Spurlock CCS + Storage Capital Total Cost	Finance	Capital Annual
$	Carrying cost	$/year
$ 10,706,151,237.07	0.177	$ 1,891,063,180.17
<u>Total Cost Summary</u> Spurlock Station, $/MWh	MWh	Total cost/MWh

Annual Payment (CCS, Transportation and Storage) accounting for all 45Q tax credit benefits		
$3,212,930,348.69*	**10,245,696**	**$ 313.59**

*This value is based on the sum of capital costs to construct CCS added to operational costs. These values are based on the generation forecast.

36. Table B provides an annual payment per year based on generation forecast taking into consideration capital (construction) costs and operational costs over 12 years and applying the benefits of 45Q tax credits. A carrying cost is also applied for financing.

37. East Kentucky included the impacts of the 45Q tax credit for carbon capture on the cost of the project to the cooperative and its ratepayers. East Kentucky calculated the value of the 45Q credit at $73.29 per MWh or $77.11/ton. When applying that value to reduce the cost of CCS, the net remaining cost per megawatt hour is $129.02. When applied to Spurlock's estimated hours per megawatt, the annual cost of CCS is $3.2 billion dollars, $1.321 billion in the cost of operating a carbon capture system, including 45Q and capital annual payment of $1.891 billion annually or an increase to normal costs of $313.59/MWh, an alarming increase in rates to rural Kentuckians.

38. East Kentucky calculated the estimated cost of the project, including 45Q tax credits, on its ratepayers. The 45Q benefits do not practically take effect until approximately 2 years after the project begins operation. Consequently, East Kentucky must shoulder $10.7 billion in costs during project development and in the early years of CCS operation. A project of this magnitude would be impossible for East Kentucky to finance —even without long-term expenditures, such as carrying costs—because just the initial capital outlay far exceeds the cooperative's entire balance sheet and ability to support this financing activity. After investing billions of dollars for CCS, East Kentucky will produce fewer megawatts of electrical generation than it produces now due to parasitic load.

39. The 45Q credit reduces the cost of CCS to ratepayers, but that benefit does not practically take effect until approximately 2 years after the project begins operation. Therefore, it is crucial to evaluate the costs to ratepayers prior to benefits begin flowing from 45Q and then after those benefits take effect. Importantly, 45Q tax credits expire in 12 years, limiting their long-term benefits to East Kentucky's ratepayers.

40. East Kentucky calculated the rate impact, including 45Q, to a residential customer at the end of the line. On a monthly basis, an average residential bill would cost $157, but with CCS, the bill increases to $263 - 308, based on the number of kWh required to power an average Kentucky residence. This is a 67 – 96% increase to residential bills, solely based on adding CCS to Spurlock. Such an increase is staggering and not possible, nor likely to be approved by the Kentucky PSC.

Table C – East Kentucky Rate Projections – CCS Impacts

East Kentucky Rate Analysis	12 years	30 years
Incremental Residential Rate (per kWh)	$0.12483	$0.08709
Average usage (kWh)	1210	1210
Incremental Average Increase	$151	$105
Average Residential Bill	$157	$157
Bill plus GHG Increment	$308	$263
% Increase over current rate	96%	67%

41. The costs presented are for Spurlock only. They do not include the cost to treat the flue gas at Cooper, which would require a separate system entirely, for the two units at that facility.

42. The costs of CCS would ultimately be passed to the customers at the end of the line, the vast majority of whom would be very unlikely to be

able to afford the rate increase. To put that cost in perspective, an average Kentucky household would receive electricity bills that are double the amount billed with 45Q prior to the Final Rule, even accounting for the benefits of 45Q. This estimate would escalate in the winter when heating requirements are highest. East Kentucky's customers that live in poorly insulated modular homes most often use electricity for heat. During winter days with temperatures well below freezing, these residents will use even more kilowatts to survive these events. The CCS price-doubling effect during peak electricity usage in extreme weather events cannot be sustained by rural end-users, particularly those in economically disadvantaged communities. The Final Rule therefore works at cross-purposes to one of the express cornerstones of the Biden Administration's energy policies, which is environmental justice. The economic impact of the Final Rule will be most harshly felt by those consumers who are already challenged to afford energy costs, where any consumers in energy inefficient housing would see energy costs exceed housing and/or food costs on a monthly basis.

43. In summary, to treat all of the flue gas at Spurlock using CCS on a continuing basis, the price tag would be $10.7 billion, including the capital cost, storage cost, transportation cost, project carrying cost, and operation & maintenance cost. This price tag is unquestionably excessive, and CCS as a compliance strategy is unsustainable and dangerously naive.

II. Impacts of Natural Gas Co-firing as a BSER Alternative

44. As an alternative to CCS, the Final Rule allows affected EGUs to remain in operation until January 1, 2039 if they begin co-firing with 40% natural gas by 2030. Natural gas co-firing may not be achievable at all of East Kentucky's coal-fired units. East Kentucky's bituminous units (Spurlock Unit 1 and Unit 2 and Cooper Unit 1 and Unit 2) can be retrofitted to co-fire with natural gas, but the project is exceedingly expensive, as explained *infra*. East Kentucky is presently evaluating whether co-firing is feasible for Spurlock Units 3 and 4. These units utilize Circulating Fluidized Bed ("CFB") technology, which is designed to lower emissions utilizing a fluidized bed in the boiler. Spurlock Units 3 and 4 were not designed to co-fire natural gas. The Final Rule does not take into account the various technologies for

deriving fuel from coal-fired generation units. A "one size fits all" approach is unreasonable and unworkable.

45. For the other East Kentucky coal-fired units, the ability to co-fire theoretically exists, but requires new infrastructure that does not exist. The closest natural gas transmission pipeline is over 40 miles away. East Kentucky estimates that the cost of the required pipeline would be approximately $500 Million, which exceeds the value of $400 to $450 million per line that East Kentucky provided in comments for the Rule.

46. Given the long lead times for construction projects, a pipeline operator must begin design, permitting, siting, procurement, and construction immediately to have natural gas available in time for the Final Rule's 2030 deadline. But no operator is likely to take all those steps without a substantial, up-front commitment from East Kentucky—in the form of a long-term (20–30 year) supply contract. Even if East Kentucky identified an operator and agreed to such terms, there is no guarantee that such a pipeline would actually be completed on a timely basis. Permitting, construction delays, right-of-way issues, and myriad other factors could block the

pipeline or could delay it beyond the Final Rule's deadlines, which are discussed in more detail *infra*. This places utilities such as East Kentucky in a completely untenable position where their ability to comply with the Final Rule is reliant upon the actions of pipeline developers to construct and operate new pipelines in near record time.

III. Impacts of BSER Alternative Retirement Options

47. The remaining option would shut down 1,519 MW gross of East Kentucky's coal generation by 2032. This alternative would require East Kentucky to build replacement generation assets or purchase power from the market – assuming it is available – to meet its electricity demands. This option creates substantial reliability concerns. At a time when Kentucky has already experienced rolling blackouts due some utilities' ability to serve load during peak winter conditions based upon the *existing* resource portfolio, forcing the arbitrary, premature closure of thousands of megawatts of existing baseload capacity will place even greater strain on the ability of grid operators to keep power flowing and meet demand.

48. *Replacement Power*. Congress authorized funding through the Inflation Reduction Act to build solar arrays and other renewable resources for cooperatives. East Kentucky is actively engaging to do so with the assistance of the United States Department of Agriculture Rural Utilities Service. However, renewable generation is intermittent, running appropriately 25% of the time as compared to the higher, dispatchable capacity factors of retiring coal units or natural gas-fired units. East Kentucky looks forward to the opportunity to add more renewable resources, including filing for regulatory approval of two brand new solar facilities last month, but those resources are not a substitute for dispatchable energy generation.

49. East Kentucky is highly concerned with the timelines to replace generating assets given regulatory requirements, timelines, and costs to replace 1,883 MW gross of coal-fired generation. The Final Rule prematurely retires existing generating assets while East Kentucky is facing increased demand for electricity in East Kentucky's service area. East Kentucky is concerned by potential delays subject to market conditions due to:

a. *Supply chain delays and costs*. Original equipment manufacturers will soon be inundated with new purchase orders from EGUs across the country. For example, the lead time for the step-up transformer necessary to connect new gas units to the grid is already 36 months. That number will only grow if the Final Rule takes effect. This creates a "race" among EGUs that need to order new equipment, each one hoping to be nearer the front of the queue. East Kentucky is not immune to that dynamic. Thus, East Kentucky has no choice but to soon begin purchasing equipment before the courts can adjudicate NRECA's challenge to the Final Rule on the merits. Electric Generating Utilities will be in the market at the same time, resulting in an imbalance between supply and demand, which arbitrarily escalates prices for virtually everything.

b. *Labor market delays*. Complying with the Final Rule will require East Kentucky to hire a large number of consultants, engineers, attorneys, and other professionals to manage the vast amounts of design, modeling, permitting, and other work required under the Final Rule. Yet these markets are also subject to the laws of supply and demand. As utilities across the nation rush to hire the same professionals, prices will increase. Accordingly, utilities must move early—not only to insulate themselves from price pressures, but also in an attempt to ensure that the needed professionals are even available on a timely basis.

c. *Gas Pipeline Construction Delays.* Recent projects to build natural gas pipelines have been substantially behind. Numerous challenges contributed to projects extending far beyond their planned schedules.[7] Specifically, eminent domain challenges and FERC approvals have slowed construction. The FERC approval timeline for new pipeline projects has consistently

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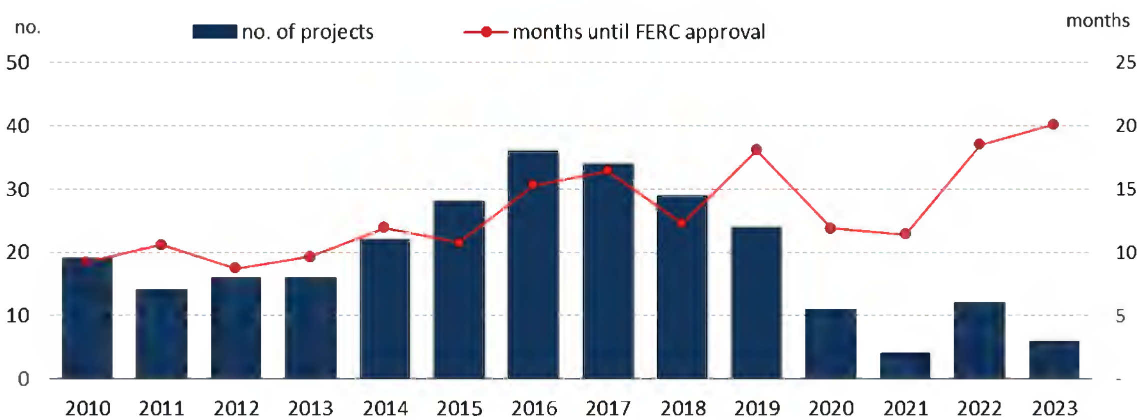
[7] FERC certificate applications are often subject to public scrutiny for gas pipelines, resulting in significant delays and potential protracted litigation. Congressional Research Service, "Interstate Natural Gas Pipeline Siting: FERC Policy and Issues for Congress" (June 9, 2022). For example, increased public scrutiny and opposition to any new pipeline project in the country (e.g., Mountain Valley, Keystone XL, Dakota Access) has led to a significant increase in approval time for new pipeline projects.

increased since 2010 (excluding 2020 and 2021, which were impacted by the COVID-19 pandemic). In comparison, the average project approved in 2023 spent over 20 months in the FERC approval process. Aside from the increased length of the FERC approval process, FERC actually approved fewer projects each year since its peak in 2016. In 2022, the commission only approved 12 pipeline projects. The following Table D, using FERC data, illustrates these real-time delays and the diminishing numbers of project approvals.

Table D – FERC Approval Length of Time



Source: FERC natural gas pipeline approval database

d. *Activation and Deactivation RTO Interconnection Delays*. Deactivation requires notice and coordination with the RTO. PJM requires as little as 90 days of advance notice prior to the proposed deactivation date, at which time PJM conducts a reliability analysis.[8] This analysis determines whether any transmission grid reinforcement is necessary to ensure the reliable flow of power to load centers in PJM. Significant network upgrades (costs) are likely necessary to reinforce the transmission system due to the lack of generation. The Final Rule will generate a substantial number of coal-fired unit deactivation requests within the same time period (2028-2032). Analysis of each of these requests individually and collectively would be quite complex, particularly given that, collectively, large-capacity deactivations are anticipated to occur within a narrow,

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[8] PJM Open Access Transmission Tariff (OATT), Part V, Section 113.1. PJM batches all deactivation requests on a quarterly basis and then has 60 days following the end of the quarter to perform the reliability analysis.

overlapping, not-too-distant time frame, which will have significant grid implications. An activation proposal to add generation must be studied to determine whether any transmission grid reinforcements must be constructed prior to the generator injecting power into the grid. Studies ensure that the electricity produced can be delivered to load in the region. The magnitude of interconnection requests and the inefficiencies inherent in the interconnection processes severely delay the timeline for bringing a new resource on-line. Many Regional Transmission Organizations, including PJM, have 25% or more requests backlogged in the process. PJM has reformed the process and is working through the backlog of projects. However, the most optimistic scenario for any new project entering the queue today is that PJM would likely require until 2028 to complete the necessary analysis to finally determine what is required to allow the unit to reliably connect to the system by the future anticipated in service date. Signing a

Generator Interconnection Agreement in 2028, for example, does not mean that the new generator will begin to inject power in 2028. Moreover, successful completion of the study process does not necessarily ensure that the resources connect and contribute to the reliability of the system. A concerning trend has been observed. According to Lawrence Berkeley National Laboratories, more than 300,000 MW of projects have been approved nationally but have not proceeded to construction – nearly 25% of current generating capacity in the country. Right now, PJM has cleared nearly 40,000 MW of generation projects through the interconnection process that are not moving to construction. Nothing from PJM is holding these projects back, yet they sit idle in PJM and elsewhere due to continued challenges with supply chain, financing and local siting issues.

e. *Purchasing Power Unhedged Off the Market*. East Kentucky would place itself in great economic peril if it did not pursue replacement "steel on the ground." The Kentucky Public Service

Commission "does not expect to allow a utility to depend on market-purchases for its long-term capacity needs . . . . it follows that market capacity is not the cost the utility is avoiding. Rather, the likelihood is that the utility will replace generation capacity with "steel in the ground" or a Purchase Power Agreement. Order, Case No. 2021-00198 (Ky. P.S.C. Oct 26, 2021).[9] By forcing generation shifts based upon arbitrary standards that are impossible to satisfy, the Final Rule has the effect of usurping state authority over resource planning and ratemaking.

f. *State regulatory delays*. Kentucky Senate Bill 4, enacted as 2023 Kentucky Acts Chapter 118, provides that a utility cannot retire an electric generating unit without the approval of the Kentucky Public Service Commission. The Commission's decision is discretionary based on its review of factors set out in the statute. Thus, there is no guarantee that the Commission would allow

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[9] East Kentucky Annual PURPA QF Tariff Filing, Case No. 2021-00198 (Oct. 26, 2021), https://tinyurl.com/mwtvwka4

East Kentucky to retire any EGUs that cannot be brought into compliance with the Final Rule. This could put East Kentucky in the uneasy position of not being able to comply with the Final Rule and simultaneously not being able to avoid violating the Rule by retiring EGUs that cannot be brought into compliance.

IV. Overall Impacts of EPA's BSER Approach

50. No matter what subcategory it chooses for Spurlock and Cooper, East Kentucky must immediately begin spending extraordinary sums of money across several expense categories (and indeed already *has* begun planning these expenses in preparation for having to comply with the Final Rule), and these expenditures might not be enough to maintain grid reliability.

51. These expenditures are shouldered by East Kentucky's member cooperatives and, ultimately, by end users in rural communities – many of which are in communities of poverty.

52. If the Final Rule takes effect, electric markets will be highly constrained, as generators across the country will see reductions in their portfolios.

53. Depending wholly on the market for 1,883 MW gross of baseload power at a time when the entire market is being forced to prematurely retire baseload EGUs that are the backbone of the bulk power grid is not possible or realistic given the economic exposure and regulatory requirements in Kentucky that require East Kentucky to replace generation capacity with "steel on the ground."

54. Accordingly, East Kentucky must construct new generation to replace any capacity coming off the grid as a result of the Final Rule and the increased demand for electricity in Kentucky. Yet the Final Rule also imposes stringent requirements that apply to new EGUs, which must achieve 90% capture of carbon using CCS for base load generation. CCS is not possible for a new natural gas EGU without a feasible and cost-effective means to transport and storage the captured CO_2 – even if a 90% capture rate can be achieved for a gas unit. Nor can East Kentucky depend on intermittent

renewables for baseload generation. The Final Rule has the effect of frustrating East Kentucky's ability to provide reliable and affordable power.

55. The Final Rule's requirements relegate gas-fired units to the intermediate or low-load categories if CCS is not installed. CCS has not been adequately demonstrated or commercially available for natural gas combined cycle operations. The new generation options in the Final Rule have an immediate detrimental impact on East Kentucky's ability to construct replacement generation.

56. Since CCS is not an option for East Kentucky, the cooperative is faced with two unworkable alternatives:

a. If East Kentucky constructs a natural gas combined cycle unit, that new unit could be limited to a 40% capacity factor based on the intermediate load category's CO_2 emissions requirements. A natural gas combined cycle is a large capital investment at $1,576 per kilowatt hour, yet East Kentucky would have to build two natural gas combined cycle units to reach the same generation capacity that one unit is capable of achieving. This outcome is absurd on its face. In other words, the project price tag would arbitrarily be doubled simply by bureaucratic fiat in order to achieve the same net generation output.

b. If East Kentucky constructed a natural gas simple cycle turbine, that new unit could be limited to a 20% capacity factor based on the low load category's CO_2 emissions requirements. A natural gas simple cycle turbine is also a significant expenditure and investment.

57. In summary, the Final Rule's requirements are detrimental to East Kentucky, its members, and end users. By requiring CCS, the requirements substantially restrict East Kentucky from adding new generation or continuing to operate its existing assets for their full useful life as originally envisioned by regulators. Reliability is at stake due to the dual threat that the Final Rule imposes on existing and new generation projects.

ABSENT A STAY, EAST KENTUCKY WILL SUFFER IMMEDIATE IRREPARABLE HARM

58. During the pendency of this litigation, East Kentucky would sustain the following concrete harms if a stay of the Final Rule is not granted:

a. The costs to immediately begin a project to construct replacement power assets to replace prematurely retiring coal assets at Cooper and Spurlock (costs which will be inflated due to economic conditions forced by industry-wide upheavals resulting from the Final Rule and the inability of venders and providers to meet unprecedented demand):

   i. Project development costs, including land acquisition, permitting, studies, engineering, and regulatory compliance costs.

   ii. Equipment costs of the new generation asset. Based on EIA data, the calculated cost of a new unit to replace the megawatts generated at Spurlock and Cooper is:

EIA Electric Power Data
Guide: EIA 860
$/kW 1576

		MWg	kW	NGCC	total, $ M
Spurlock Station		1519	1519000	1576	2,393
Cooper Station		364	364000	1576	574

* Does not include any technology integration dollars to plant site or grid
** capital costs multiplied by station capacity

b. The cost to immediately begin constructing a gas line for either a new gas unit at Spurlock and Cooper or the ability to co-fire gas at its non-CFB units.

c. The cost to launch a project to retrofit Spurlock 1 and 2 and Cooper 1 and 2 to provide for co-firing with natural gas.

d. The cost to retrofit the coal-fired units with CCS. At the highest price, this option would not likely be pursued, even aside from substantial feasibility concerns raised above. It is the harm that would be incurred if East Kentucky complied with BSER for existing coal-fired units.

59. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded. Legally binding retirement promises cannot be undone. The costs of these projects are more than several multiples of East Kentucky's entire balance sheet.

60. The Final Rule imposes substantial financial harm to East Kentucky by stranding existing debt on its coal-fired assets. East Kentucky

would still hold $774.811 million in debt for the units at Spurlock on the compliance date to shutdown coal in the Final Rule (December 31, 2031).

61. Demand for electricity in Kentucky is steadily increasing. East Kentucky is looking to commence construction to obtain new and replacement generation during the pendency of this litigation. East Kentucky is harmed by the Final Rule's restrictions on new generation, which would require East Kentucky to commit to double its project scope (*e.g.*, two combined cycle units instead of one) to achieve the same number of megawatts to meet demand. Gas generation projects can only realize 40% or less of the heat input capabilities of the units without CCS technology.

62. If East Kentucky must purchase power from the market, that market price varies based on many market factors. PJM real time market costs ranged from $4,199 (December 23, 2022) to $9.07 (August 20, 2023) per MW/hr looking at data from 2022 through 2023. PJM market prices in 2022 averaged $80.14 MW/hr., which was an 101% increase over the 2021 average megawatt per hour price. Market exposure could harm East Kentucky to the extent that its entire financial security would be in jeopardy.

63. Market pricing during a grid failure could result in extreme power prices that quickly lead to the bankruptcy of a generation and transmission cooperative, which is what happened to Brazos Electric Power Cooperative during the Texas 2021 ice storm.

64. The Table E below illustrates the cost to replace generation from East Kentucky's existing coal generating plants on December 23, 2022 and December 24, 2022 when Winter Storm Elliot hit. Market clearing prices skyrocket when the market is short of energy reserves, exposing unhedged load-serving entities. If Spurlock and Cooper were unable to operate, the total cost would have been ***over $74.5 million for just two days of extreme cold***. These costs would be passed along to East Kentucky's ratepayers. Some of the nation's poorest communities, which are located in East Kentucky's service territory, cannot and should not have to bear this tremendous risk and burden.

Table E – Cost to Purchase Generation on the Market

East Kentucky Coal-Fired Generating Stations	**December 23, 2022**	**December 24, 2022**
Spurlock Station	$25M	$34M
Cooper Station	$6.5M	$9M

Total Power Purchase Cost	$31.5M	$43M

65. A summary of East Kentucky's financial harms is provided in Table F below:

Table F -- Summary of Costs of the Final Rule to East Kentucky

East Kentucky's Financial Harms	Cost	Source of cost
Cost of Constructing Replacement Generation	$1,579.64 /kW	EIA Form 860
Cost of Constructing a gas line to Spurlock	>$500 million	Estimates
Cost of Constructing a gas line to Cooper	>$500 million	Estimates
Cost of stranding debt on the Rule's compliance date	$774.811 million	Financial records
Exposure of Purchasing replacement MWs in the PJM market	Variable. Exposure can be extreme as depicted by the cost of $74.5 million (dollars per megawatt hour) for two days of replacement electricity in December 2022	PJM Market Costs; see Table E
Cost of CCS as applied to Spurlock, including capital, transportation, storage and carrying costs	$10.7 billion capital, annual payment estimate, $1,891,063,180.17/year, $129 per MWh CO2 w/ 45Q, estimated cost $1,321,867,168.52 / year	Based on calculations using Project Tundra as a pricing example; see Tables A and B

66. If replacement power is not available for purchase or constructed in time, reliability is at stake. A grid failure would cause damage to East Kentucky, its members, the economy, and the public health of end users in its service territory. Kentuckians rely on electricity to heat and cool their homes. Affordable and consistent power allows for medical providers to provide essential services to the elderly, infirm, and to vulnerable individuals with chronic health conditions. Evidence from grid failures in other areas of the country in winter storms Uri and Elliott shows the documented health impacts and morbidity caused by those events. Other concrete damages would occur such as business shutdowns, food spoilage, property damage, and lost labor productivity. Further economic development in Kentucky is at risk without the ability to provide sufficient energy to support new factories, data centers, and other infrastructure necessary to attract industry, and, in turn, create new jobs. Energy powers the economy from which the government derives tax revenues. Reliability consequences are at stake prior to the resolution of this litigation due to the increased demand for power in Kentucky and the premature retirements

and limitations on the construction of new generation imposed by this Final Rule.

67. All of these near-term costs will begin flowing immediately to East Kentucky's members—and ultimately to the rural ratepayers who depend on it for reliable service.

68. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of NRECA's Petition for Review. East Kentucky expects that process to take *at least* 3-5 years (indeed, litigating the Clean Power Plan took 7 years). But the Final Rule's compliance deadlines do not give East Kentucky any time to spare.

69. If the Rule remains in effect while NRECA's challenge to the Rule is pending, East Kentucky will have no choice but to incur significant non-refundable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above. And the consumers who rely on power generated by East Kentucky might find themselves with less reliable power or without the means to pay for it, or both.

*   *   *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 9th day of May, 2024, in Winchester, Kentucky.

Jerry B. Purvis, Vice President of
Environmental Affairs

Appendix 7

DECLARATION OF ROBERT MCLENNAN

I, Robert McLennan, declare as follows:

1. My name is Robert McLennan. I am the President and Chief Executive Officer at Minnkota Power Cooperative ("Minnkota"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have more than 29 years of experience in electricity generation. I have been employed at Minnkota since 2011. I hold dual bachelor's degrees in history and political science, and psychology from the University of Jamestown. As President and CEO at Minnkota, my responsibilities include ensuring access to safe, reliable, affordable and sustainable electricity for 11 member-owner cooperatives in eastern North Dakota and northwestern Minnesota. This includes oversight of more the 400 employees and a budget of more than $450 million annually.

3. Minnkota is a member of the National Rural Electric Cooperative Association ("NRECA"), the Lignite Energy Council ("LEC"), and America's Power.

4. This declaration is submitted in support of staying the EPA's final rule 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*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

5. I am familiar with Minnkota's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect Minnkota as well as its suppliers, members, consumers, and employees.

6. Minnkota's planned "Project Tundra" facility would be the largest CCS project that the world has ever seen. Yet because of the Final Rule, it may never get built. That is because this state-of-the-art project is still

not enough to bring Minnkota's Young Station into compliance with the Final Rule. This despite the fact that $90 million and nearly a decade of planning have already gone into Project Tundra. Even if it were technologically possible to expand Project Tundra's scope—something no one knows, since no similar project has ever been attempted—the Final Rule does not leave anywhere near enough time for that expansion. Designing the current scale of CCS for Project Tundra took almost a decade. Yet the Final Rule requires Minnkota to update that design with a new, expanded CCS system and bring it into operation within about half that time. That is impossible.

7. Minnkota is a not-for-profit electric generation and transmission cooperative ("G&T") headquartered in Grand Forks, North Dakota. Minnkota is owned by 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota, which together serve some 160,000 member cooperative rate-payers. These communities depend on Minnkota to provide cost-effective electricity to sustain rural residences, businesses, schools, and farms. Minnkota also serves as the operating agent

for Northern Municipal Power Agency, which is headquartered in Thief River Falls, Minnesota. Since its formation in 1940, Minnkota has been committed to delivering safe, reliable, affordable and environmentally responsible energy to its member-owners.

8. Electric cooperatives, like Minnkota, sell most of their power to households rather than businesses unlike investor-owned utilities ("IOUs"), and serve predominantly rural areas. They operate at cost and without a profit incentive and are owned by the members they serve with no independent stockholders. Because costs of cooperatives are borne by fewer consumers, most of which are families, rate affordability is crucial to consumer-members. In addition, cooperatives have greater infrastructure needs due to the rural communities they serve, which provide fewer meters per mile of transmission lines. In fact, data from the U.S. Energy Information Administration show that cooperatives serve an average of eight consumers per mile of line and collect annual revenue of approximately $19,000 per mile of line. In contrast, investor-owned utilities average 34 customers and collect $75,500 per mile of line.

9. Minnkota owns or operates one lignite coal mine-to-mouth power plant, the Milton R. Young Station ("Young Station"). Young Station is a two-unit, cyclone lignite coal-fired power plant located near the town of Center, North Dakota. Minnkota owns and operates Unit 1, and it also operates Unit 2 on behalf of Square Butte Electric Cooperative. Square Butte is owned by the same 11 member-owner cooperatives associated with Minnkota, and it shares the same management. At Young Station, lignite coal is mined from land adjacent to the plant and is the only type of coal the plant is designed to burn. Not only does this plant provide highly reliable and affordable energy given the proximity and steady supply of lignite to the electric generating units, the "mine-mouth" model is cost-effective for dispatchable power.

10. Electricity generated by Minnkota is distributed through the Midcontinent Independent System Operator ("MISO") regional transmission organization ("RTO"). MISO "operates the transmission system and centrally dispatched market" in fifteen states ranging from Canada down to the Gulf Coast. Across those states, it serves more than 42

million customers.[1] Minnkota and its system partners (Northern Municipal Power Agency and Square Butte Cooperative) have the capability of generating 1,425 MWs, which may be provided to MISO for scheduling and reliability purposes. Over half of the electricity generated by Minnkota is dispatchable power from coal sources, meaning it is available on demand, unlike power from wind and solar resources, which do not have on-demand capabilities. Dispatchable power is critical for MISO because MISO has small reserve margins, which is the amount of power needed to ensure demand is met and avoid failure of the grid.

11. Minnkota is proud of its extensive decarbonization efforts, including a renewable portfolio that comprises 42% of current generation resources.

12. In 2015, Minnkota undertook the role as lead sponsor of a carbon capture and sequestration ("CCS") project adjacent to the Young Station. This project, known as "Project Tundra," aims to treat the flue gas from the

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[1] FERC, MISO, https://www.ferc.gov/industries-data/electric/electric-power-markets/miso.

Young Station's two cyclone lignite-fired coal units, located near the town of Center, North Dakota. Minnkota, as the owner-operator of Young Station, has a strong interest in and is uniquely positioned to evaluate the Final Rule.

13. Although Minnkota strongly supports investment in CCS technology, the Final Rule drastically overstates the technology's current and future capabilities, as well as the timeline in which CCS can feasibly be deployed. Other aspects of the Final Rule pose new, grave reliability concerns that will lead to additional premature retirements. All of this will only compound the existing shortage of reliable, dispatchable generation. As a small, cost-sensitive cooperative, these shortages are of particular concern to Minnkota. So too are the Final Rule's massive costs and aspirational timelines.

OVERVIEW OF THE FINAL RULE

14. The Final Rule establishes CO_2 emissions limits that States must apply to existing coal-fired units, under Section 111(d). 89 Fed. Reg. at 39840. It also establishes limits for CO_2 emissions from new gas-fired combustion turbines, under Section 111(b). *Id.* at 39902. Under these limits, both existing

coal-fired units and new gas-fired combustion turbine units must meet a stringent "presumptive standard of performance." *Id.* at 39836; *see id.* at 39823-24. That standard is the degree of emission reduction achievable by the application of 90% carbon capture and sequestration/storage ("CCS"). *See id.* 39801-02. Existing coal-fired units that do not deploy CCS must shut down (unless a State or federal regulator successfully invokes one of the Rule's complex and discretionary exceptions). New units that do not reduce emissions to meet the presumptive standard must drastically reduce their output of electricity.

15. The Rule divides existing coal-fired units into three non-overlapping subsets: two "subcategories" and one "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit makes a federally enforceable commitment to retire, and by the date of that retirement. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *See id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

16. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

17. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent "—*i.e.*, transforming a coal unit into one that combusts both coal *and* natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

18. Third, units that make a federally enforceable commitment to permanently cease operating by January 1, 2032 have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

19. For new and modified gas-fired combustion turbines, the Rule creates three subcategories, which are "based on electric sales (*i.e.*, utilization) relative to the combustion turbines' potential electric output to an electric distribution network." *Id*. at 39908.

20. "Low load" units are those that supply 20 percent or less of their potential electric output as net-electric sales. *Id.* at 39917. They must use lower-emitting fuels. *Id.* "Intermediate load" units are those that supply more than 20% but less than or equal to 40% of their potential electric output as net-electric sales. *Id*. These units must use highly efficient simple-cycle turbine generation technology. *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of

performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO_2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

MINNKOTA'S EXPERIENCE WITH CCS

21. Minnkota and its project partners are pursuing construction of a CCS project adjacent to the Young Station known as Project Tundra. If it commences operation, it will be North America's largest CCS facility in scale. The project will treat approximately two-thirds of the flue gas of Units 1 and 2 to reduce and capture CO_2 emissions. The project is designed to capture CO_2 at a capture efficiency of approximately 95% of the treated flue gas from either unit at the Station, with the CO_2 stored more than a mile underground. The project will be two and a half times the size of the Petra Nova project that is located in Texas (as discussed below).

22. Project Tundra was first conceived in 2015. At this time, commercial operation is projected to begin in 2029 (if at all). That is a 14-year runway, which is almost *triple* what the Final Rule contemplates. And even

with all that extra time, **Project Tundra *still* would not fully comply with the Final Rule.**

23. Minnkota's experience with Project Tundra shows that 90% capture of carbon emissions using CCS is not adequately demonstrated and is not achievable as conceived by EPA. Project Tundra has been in development for almost a decade (since 2015).

24. Minnkota has spent approximately $90 million on design, engineering, consulting, site studies, and numerous other pre-construction activities. Approximately $60M of that investment was State and Federal government-funded. Even with all that investment and time, Minnkota has not made a final investment decision nor issued full notice to proceed with construction of Project Tundra. Instead, Minnkota anticipates making a decision about whether to go forward with the project later this year. Even if Project Tundra does go forward this year, commercial operation is not anticipated to occur until 2029.

25. To support EPA's contrary view, the Final Rule identifies only a small list of projects. SaskPower Boundary Dam Unit 3 is a 110 MW lignite-

fired unit in Saskatchewan, Canada. But it has been plagued with shutdowns and unexpected maintenance, and it has never been able to consistently achieve 90% carbon capture using CCS. The Petra Nova capture facility (a 240 MW capture at Parish Generating Station in Thompson, Texas) operated for three years between 2017 and 2020 and has only recently begun operating again. It is the *only* CCS system that has *ever* operated at a coal-fired facility in the United States. Plant Barry had a small pilot CCS project (a 25 MW slip stream capture system in Mobile, Alabama). The project was not comparable to the commercial scale generation that the Final Rule addresses. In other words, none of these projects have demonstrated successful, continuous operation of CCS at a 90% capture rate on a scale than could even conceivably be deployed to accommodate larger power generating units in this country.

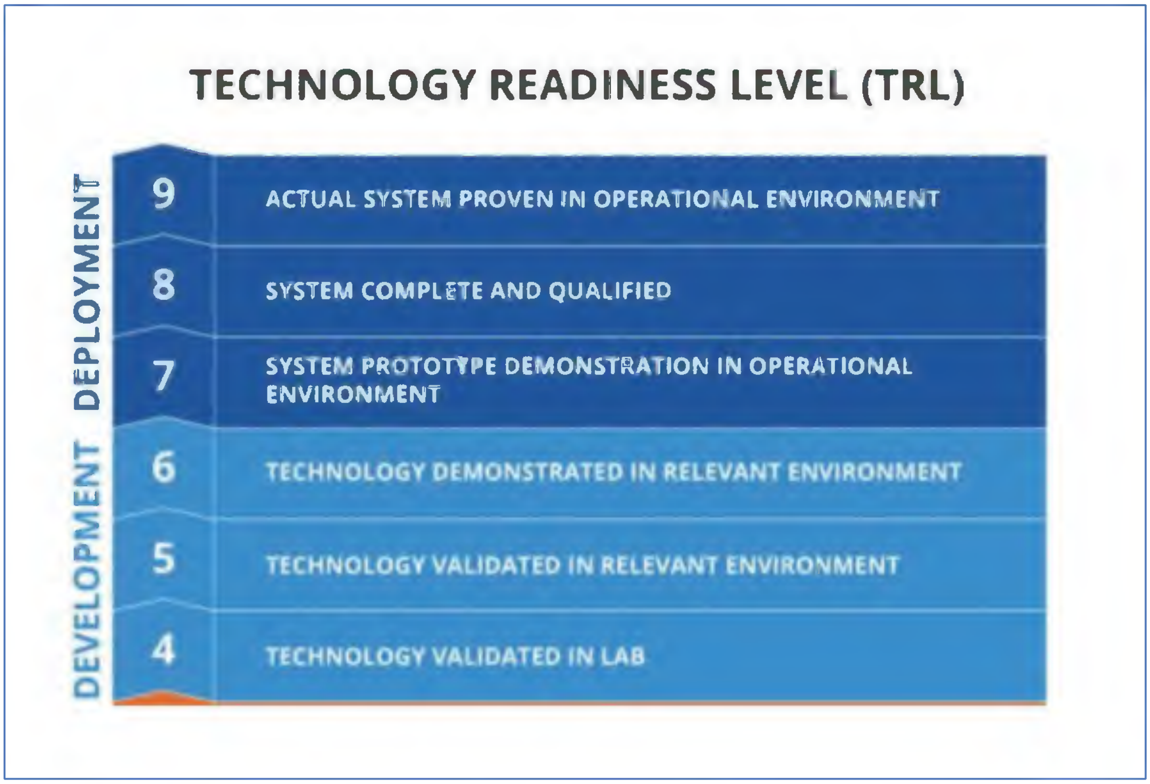
26. Minnkota's experience with Project Tundra versus EPA's assumptions in the Final Rule are starkly different. With respect to the storage component of the CCS process, Minnkota agrees with EPA's assessment that geologic sequestration of captured CO_2 is available in some

parts of the country, such as in North Dakota. Yet, it is not available universally. Many of the other assumptions in the Final Rule are similarly inconsistent with Minnkota's experience.

A. CCS technology has never been demonstrated.

27. CCS is potentially feasible, but it has not ever been adequately demonstrated. To be adequately demonstrated, CCS must be possible at all sites with existing coal-fired units, at all boiler-types, and at all loads. Minnkota's experience confirms this is not true. Of most significance, CCS has not been proven, even as a pre-demonstration project, at the size needed to treat the flue gas of a large coal-fired EGU.

28. Project Tundra is financed as a Technology Readiness Level (TRL) 7 project. TRL 7 projects are defined as "system prototype demonstration in an operational environment." TRL 7 projects have results from testing a prototype system in an operational environment but the technology has not been proven to work in its final form and under expected conditions to achieve TRL 8 status. TRL 9 projects are proven in the operating environment, as the graphic below illustrates:



29. The units at Young Station are a 455 MW unit (Unit 2) and a 250 MW unit (Unit 1). Yet Project Tundra only has capacity to treat 530 MW, with Unit 2 as the principal design unit.

30. If carbon capture were "demonstrated," as EPA claims, then Minnkota and its partners would not be able to finance Project Tundra as presently planned. Project Tundra is requesting financing, in part, as a demonstration project through funds from the Department of Energy's ("DOE") Office of Clean Energy Demonstrations ("OCED"). The Bipartisan

Infrastructure Law enacted in December 2021 created the funding opportunity for demonstration projects. But funding is not available for technologies that are proven at a commercial scale. To obtain funding from OCED, DOE looks at "technology readiness levels." It provides funds to projects that show advancing technology. The Project Tundra demonstration results from the bold investment to take CCS farther than before. The Project seeks to advance the technology readiness level of CCS by scaling up the technology (2.5x), applying it to lignite-fired coal units, and showing successful operations in the extreme weather climate of the upper Midwest. None of that has been done before.

31. Minnkota has acknowledged and carefully calculated the technology risk, taking account of site-specific variables. A crucial assumption in Minnkota's calculus is that the Young Station units may operate and generate electricity even if the CCS equipment has an outage. In other words, if equipment issues arise – whether due to the CCS technology, equipment, increased scale, extreme temperatures, or variability in flue gas load – the CCS system may take a forced outage. Meanwhile, the Young

Station units are able to generate electricity and emit flue gas through the current stack configuration while CCS is down and as the CCS starts up after outage. Thus, the risk of equipment failure is much less detrimental than if the entire Young Station must come offline for the entire duration of the CCS plant forced outage. In that event, Minnkota would be hedging its ability to meet generation needs on the CCS project equipment, a much different risk proposition for Minnkota's member-owners. Yet the Final Rule would compel consideration of this very result.

32. Carbon capture at a large-scale coal-fired unit or any natural gas unit has not been demonstrated. In fact, Project Tundra seeks to prove that large scale coal-fired application is possible. Project Tundra aims to capture the CO_2 emissions equivalent to a 530 MW unit. Project Tundra's scale will be the largest capture system in the world and will employ the largest single train system (i.e., all CO_2 sources fed to a single absorber) that has been built by any project manufacturer. But even the largest designed train is **still insufficient to cover EPA's anticipated scope,** which in Minnkota's case

would be 705 net MW of flue gas. An additional CCS train would be necessary.

33. Similarly, carbon capture is not adequately demonstrated to continuously achieve 90% capture of CO_2. Project Tundra is **designed** to capture 95% of the CO_2 in the flue gas when CCS is at **full load** and receiving flue gas from a combination of Unit 2 and Unit 1. The carbon capture process uses a complex chemical reaction to separate the CO_2 from other constituents in the flue gas and then prepare captured CO_2 for storage. Carbon capture efficiency and the operating implications on other important process parameters when the flue gas stream is at a lower load is not yet demonstrated or fully understood. Project Tundra's full load 95% design rate may not apply at lower flue gas loads.

34. Minnkota has no technical data or testing assurance that EPA's value of 90% carbon capture can be achieved across varying unit loads. In addition, weather (seasonal temperature) impacts are anticipated to affect the CCS equipment function. Based on Minnkota's understanding from project development, this demonstration project will help to provide

information on operation, which are presently at scale not demonstrated. The parameters for Project Tundra were never dependent on achieving a specific capture percentage continuously. Further testing and vendor information is necessary to target an achievable capture percentage that could be applied to all unit sizes, project scales, weather conditions, pollution control trains, and load levels with a margin for compliance. A margin for compliance would also be required.

B. CCS causes reliability issues that remain unresolved.

35. The Final Rule all but ignores the practical consequences of CCS. The electrical and steam requirements of a capture system are consequential. The electrical and steam requirements of carbon capture systems will reduce availability of a significant amount of generation from the grid in four ways: (1) Inadequate scale of CCS systems to treat the flue gas of a large unit; (2) Forced outages due to CCS equipment; (3) Inability to achieve 90% CO_2 removal at all loads; and (4) Diversion of electricity from the grid to run the CCS system.

36. In Project Tundra's case, 205 MW from the Young Station units is needed just to operate the adjacent CCS facility. In total, the CCS demand is about 31% of the Young Station's net capacity. This value is equivalent to retirement of a smaller generating unit. The cumulative demand to serve multiple CCS facilities—which is what the Final Rule contemplates—would severely strain the grid. That means that about 205 MW of the 734 MW Young Station would be needed to support CCS at Young Station rather than for sale as electricity on the market. CCS projects across the country would, if attempted, cause removal of megawatts from the nationwide grid, exacerbating reliability concerns that should be studied.

37. Forced outages due to CCS equipment failures will also remove generation from the grid. At present, no regulatory requirements constrain the Young Station from operating *even if* the CCS system experiences a malfunction. It is crucial to preserve the ability for units to function in must-run situations to abate a grid emergency.

C. CCS's tremendous expenses are possible only with support from government funding.

38. CCS Projects are very expensive due to development, one-time capital costs, and ongoing operating costs. Project Tundra is estimated at a cost of over $1.6 billion. The project will be financed by utilizing 45Q federal tax credits, which are currently $85 per ton of CO_2 that is captured and stored in a geologic formation deep underground. Permitting is completed for an adjacent second CO_2 storage site. If this federal subsidy were not in place, the project would not be economical. These costs are even more substantial for smaller generators, such as cooperatives.

39. Financing options are essential but limited. CCS projects are only possible through multiple funding sources. Project Tundra will use DOE funds, including assistance from the Inflation Reduction Act, and Department of Agricultural Rural Utilities Services ("RUS") funding. And the State of North Dakota is providing a $250 million loan to assist the project. Private loans are more challenging to obtain for demonstration projects. Projects of the scale required by the Final Rule would require

similar or greater levels of funding which will inevitably constrain the market and the funding opportunities available.

D. CCS storage is not achievable nationwide.

40. Many areas of the country do not have the geology to support sequestration. The Young Station happens to be placed on ideal geology for safely sequestering carbon, as demonstrated in the figure below. However, much study was necessary to arrive at this conclusion. In 2005, the Energy & Environmental Research Center ("EERC") at the University of North Dakota started characterizing the geology within the state and targeting storage formations. It took the EERC **over a decade just to characterize the geology**. Most sites do not have a deep porous rock layer to hold the CO_2, nor do they have overlying cap rock layers that will seal the CO_2 in the storage formations. Sites that do not have this geological setting must transport the extracted CO_2 to geology that is secure for storage. Dedicated piping must be available, adding even more cost to a project.

41. States with oil and gas frameworks, like North Dakota, will have a shorter timeline for exploring and permitting storage. North Dakota has an oil and gas and mining regulatory framework to study storage geology and issue permits. Many states do not have regulatory frameworks nor staff with any experience in this type of natural resource development. Time would be necessary to enable those states to develop a regulatory framework that supports sequestration and drilling and addresses ownership of natural resource pore space to lessen the possibility of future legal challenges for projects and permits. Further constraining the timeframe is EPA's own regulatory backlog, to obtain an EPA Underground Injection Control Class

VI permit to allow storage of CO_2 is an arduous process. A tremendous amount of information is needed. For example, EERC needed over a decade to characterize the geology. After that characterization, in 2020, Minnkota drilled two characterization wells to gather the necessary geologic data to support a permit application. This step was required to obtain a complete application.

42. Class VI permits are also expensive. For Project Tundra, the necessary storage permit cost was in excess of $30 million. This cost is likely reduced because the work was performed during the COVID-19 pandemic lockdown when rig costs and labor were less expensive due to availability. In the future, the cost might be double, particularly when utilities are competing over limited drilling resources. And Class VI permitting is a lengthy process. North Dakota is one of only three states with primacy to issue Class VI permits. North Dakota engaged in two full sessions of state lawmaking to enact laws required for EPA to grant primacy. Sources in all other states must look to EPA to grant Class VI permits. At present, 33 permit

applications are pending. Under the Final Rule, the backlog of pending applications will only increase.

E. Even attempting CCS takes massive amounts of time.

43. The Final Rule's timeline requires CCS to be fully operational by January 1, 2032. This time frame cannot be achieved.

44. For Project Tundra, project development took almost nine years of study and engineering analysis necessary to support a final decision on construction, despite exceptional geology at the Young Station. Carbon capture front-end–engineering-and-design ("FEED") studies take a minimum of 18 months (6 months for Pre-FEED studies plus 12 months minimum for a FEED study). Only four to five vendors actually have the capability to launch CCS projects. Minnkota has identified only two of those vendors able to develop CCS operations at the scale of Tundra.

45. For Project Tundra, the manufacturer selected, Mitsubishi Heavy Industries America, Inc., has been studying the flue gas characteristics of the Young Station since 2015. These studies are necessary to ensure successful capture solvent performance.

46. Environmental permitting has played a significant factor in the project timeline. The CCS facility requires water permits, an air permit, and high voltage transmission changes at the plant (re-routing).

47. Due to federal funding, the financing process itself is also subject to National Environmental Policy Act ("NEPA") environmental reviews, which can also add significant delay. Project Tundra has experienced NEPA delays. NEPA review performed through the DOE CarbonSafe Project is still ongoing. It began in 2021 to prepare the documentation necessary to submit the Environmental Consideration Summary to DOE for a determine of the type of NEPA assessment required. DOE made the decisions that an Environmental Assessment ("EA") was necessary in 2022. Two years later (2024), Minnkota is still waiting on a Finding of No Significant Impact ("FONSI") because two rounds of comments were needed. In total, the Project Tundra NEPA process has taken over three years and is still not complete.

48. Once FEED studies, permitting, and other project development work is complete, the actual construction timeline will take approximately

50 months. Since some equipment is fabricated off-site, it must be ordered to specifications well in advance. Delays are possible due to labor storages or supply chain issues.

49. Construction timelines are likely to be impacted by the demand the Final Rule would place on the small number of vendors available to develop and construct CCS projects. The construction vendors that are needed to construct CCS projects are the same vendors that undertake other infrastructure and labor-intensive projects for the power and industrial sectors. The Final Rule will cause simultaneous new CCS projects for coal and gas that will flood the field at the same time due to the concurrent due dates for these projects. In addition, EPA has further exacerbated labor demands due to the environmental upgrade projects that will be necessary to comply with the other environmental rules released along with Final Rule, including the Mercury & Air Toxics Residual Risk and Technology Review, Effluent Limitation Guidelines, and labor-intensive projects required to comply with new Legacy Coal Combustion Residuals regulations. This

demand will drive costs up for limited contractor resources and delay projects.

50. Supply chain delays will increase the time necessary to achieve commercial operation. For CCS projects, the present lead times for a transformer and power distribution center ("PDC") required for the CCS system is 94-110 weeks, based on recent contractor inquiries. These components are essential to any CCS project. That number will only grow as the Final Rule takes effect.

51. It took four years to obtain the Class VI permit for Project Tundra, including characterization of the geology for the permit application, completing the Class VI permit application, holding hearings, and obtaining the final permit. Minnkota anticipates that sites in states without a subsurface regulatory framework and primacy will require much more time. The CO_2 pipeline from the generating unit to the storage site requires additional time. Project Tundra did not require a long pipeline—only a quarter mile pipeline from the CCS equipment to the injection site on plant

property. The pipeline siting process was part of storage permitting. This is not likely to be the case for most CCS projects.

52. To summarize, **Project Tundra would not be completed in the time EPA has proposed, had the project begun today or even 4 years ago**.

THE IMPACT OF THE FINAL RULE ON MINNKOTA

53. Minnkota has no plans to retire Young Station, which is a key generation asset. But complying with the Final Rule will require substantial expenditures. The Young Station is home to the Project Tundra CCS project. **But even *with* Project Tundra, the Young Station cannot comply with the Final Rule**—despite more than approximately $1.6 billion of costs and what will be 15 years of project development efforts from conception to operation in 2029. This leaves Minnkota with two principal choices: Comply with the CCS baseload coal option or retire the Young Station. The latter would require Minnkota to build replacement generation.

54. *Using Project Tundra to Comply with the Rule.* The Rule jeopardizes Project Tundra's viability. If it is possible at the designed scale at all, achieving 90% carbon capture at Young Station would require

redesigning the Project Tundra CCS system to capture *all* of the CO_2 from both of the units at Young Station. As currently designed, Project Tundra would capture over 70% of the CO_2 from station-wide units.

55. Complying with the Final Rule's 2032 deadline would require Minnkota to immediately begin design and development and negotiate project contracts by the end of the current calendar year (at the very latest). Minnkota would need to completely redo engineering, conduct new FEED Studies, incur additional project development costs, and redo environmental permits, all of which would need to be scheduled and paid for immediately.

56. If Minnkota were to increase the scale of Project Tundra to capture an additional 205 MW (or roughly 28% of the total net load), it would cost an estimated $10-40 million in development costs alone. As a small cooperative, Minnkota does not have the resources to quickly or easily expand the project.

57. Even if resources were available, the delay for redesign and re-permitting efforts would set the project timeline back a minimum of 12 months. It is more likely that the project delay would be much longer

because Minnkota could not order key pieces of equipment that have a long wait-time (CCS transformer and CCS Power Distribution Center) until redesign of the CCS facility.

58. It is unlikely that Minnkota can build a larger scale CCS system to be available by 2032. Such a system would require new carbon capture Pre-FEED and FEED studies, environmental permitting, and site changes at the plant (transmission re-routing). The actual construction timeline will take three to four years. New equipment to cover the additional flue gas must be fabricated off-site and ordered to specifications in advance. Construction timelines would be impacted by the demand the Final Rule places on the small number of vendors that develop and construct CCS projects. Minnkota does not have adequate time to develop, finance, design, and build a new capture train to further increase the project scale. Minnkota estimates up to three years for redesign, re-permitting, financing, and compliance with environmental requirements, such as NEPA. It is uncertain whether the plant even has enough space to site a new or substantially enlarged absorber, which would be required to handle additional flue gas.

59. Minnkota has already expended $30 million dollars furthering development of Project Tundra. To have to add to the scale of the CCS process would result in significant delay to project development, design, equipment, and contractor, and result in substantial expenses that Minnkota could not bear as a small entity on top of the investment costs for Project Tundra.

60. Minnkota has advanced CCS technology for the benefit of the U.S. government and coal plants across the country, but Minnkota's years of planning, development, and acquiring funding for Project Tundra will have been for nothing if it cannot fully operate this technology as originally intended as a result of the Rule. Minnkota's resource planning has relied on this Project, rather than development of natural gas or other reliable resources of generation. This is at a huge cost not only to Minnkota, but all its members, customers, and rural Americans who depend on low-cost reliable energy. If even possible under a 2032 timeline, it would be extremely costly for Minnkota to have to entirely re-evaluate its long-term resource planning and begin immediately investing in the development of natural

gas, including siting a pipeline, design and engineering, and permitting, to comply with this Rule, all while retiring its existing coal asset—which has significant federal debt held against it—and trying to provide low-cost baseload energy to its customers.

61. If the Final Rule takes effect, electric markets will be highly constrained, as owners across the country will see reductions in their generation portfolios. Rather than becoming solely dependent on purchasing power from the constrained MISO market, the most likely cost-efficient option to address the diverted load of CCS is to build new generation.

62. *Compliance by Co-Firing is not an option for the Young Station.* Without significant study and development time, natural gas co-firing is not feasible or cost-effective at Young Station. The Final Rule allows affected EGUs to remain in operation through 2039 if they begin co-firing with 40% natural gas by 2030. There is no supply of natural gas within 30 miles of the Young Station. It is unlikely that a gas pipeline could be permitted and constructed in time for the Final Rule's deadlines. Even if supply were

available, the costs for retrofitting Young Station to co-fire with natural gas are infeasible—especially since affected EGUs would be required to shut down soon after installing this new equipment. The "medium term" compliance path is thus unavailable to Young Station.

63. *Retirement of Young Station would have significant costs.* If the Final Rule's requirements force Minnkota to abandon Project Tundra, the only remaining option for the Young Station would be retirement. This would have substantial costs for Minnkota, as well as for the lignite mine adjacent to Minnkota's Young Station, which was established for the sole purpose of providing fuel to the plant. Foremost, Minnkota would need to immediately begin securing reliable baseload power supply to offset the loss of the two units from Young Station. For the reasons discussed above (and below), action to secure replacement power would require significant expense and would need to begin immediately.

64. *Building Replacement Power to Serve Load.* The loss of Minnkota's only fossil generation station is very significant for the cooperative's ability to serve its customers with reliable, affordable electricity. It is unlikely that

Minnkota can build replacement generation to be available by 2032. However, Minnkota must begin spending money immediately for planning, design, siting, permitting, and construction.

65. *Reliability impacts of the Compliance Options*. Since the CCS technology has not been demonstrated at this scale, performance reliability early in operation is the largest risk, which under the rule introduces the likelihood to make an EGU less reliable, and thus to make unplanned outages more frequent and more severe. In other words, the DOE is funding demonstration of this technology at a commercial-scale because even while the technology has required technical and engineering adjustment to perform as guaranteed. The experience at Boundary Dam and Petra Nova shows that unplanned outages are a necessary aspect of attempting to use a new and underdeveloped technology like CCS. When scaled and applied for the first time at Young Station, CCS will undoubtedly cause upsets while operations are adjusted and fine-tuned. Minnkota anticipates this may be likely in the first 3 years after commercial operation date and that outages will need to be taken during that time. But unplanned outages increase

Minnkota's overall costs, hurt its relationships with members and consumers, and can even affect its contractual obligations with MISO.

66. Minnkota's ability to provide reliable power is especially important to the MISO system because the region is at a high risk of generation shortfall. Specifically, shift of new generation from thermal to wind and solar across the system is expected to cause a generation shortfall because renewable sources do not have the on-demand capabilities of the retiring thermal resources that can rapidly turn on and ramp up output when other generation (like solar) is unavailable.

67. Beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur. And, the North American Electric Reliability Corporation (NERC) has reported the MISO region has an "elevated" potential for insufficient operating reserves in above-normal conditions, like during weather events or in the case of increased demand. Unplanned outages due to CCS would exacerbate already existing stress on the grid and risk generation shortfalls at times when providing dependable

energy is crucial, like during the winter. Therefore, the reliability impacts of CCS are another significant cost facing Minnkota.

68. If the Young Station had to prematurely retire due to the rule, Minnkota would not have time to construct replacement generation. Minnkota's only readily available option would be to increase its exposure to, and become reliant upon, an often volatile and constrained MISO market. Past market pricing demonstrates the extraordinary costs to purchase power from the market. In fact, these staggering costs have bankrupted a small utility recently (Brazos Electric Power Cooperative) due to power purchases during Winter Storm Uri from the ERCOT market.

69. *Power demands*. Increasing power demand in the MISO region, including in North Dakota, will similarly put more strain on the grid and more stress on generation. In the first quarter of 2023, North Dakota was the top state in economic growth in the country at 12.4%, as measured by gross domestic product ("GDP").[2] Economic prosperity is due to industry growth

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[2] U.S. Department of Commerce, Bureau of Economic Analysis, "Gross Domestic Product by State and Personal Income by State, 1st Quarter 2023"

from mining, oil and gas extraction. North Dakota has also seen gains in agriculture and forestry activities. These sectors are energy intensive industries, highly dependent on reliable power.[3] Nebraska and South Dakota are similarly reporting substantial increases in GDP. Due to this increase demand, these areas have an elevated risk of reliability concerns. The adoption of CCS as BSER will only heighten this risk, as it poses a threat to the availability of important baseload generation.

70. *Extreme weather*. Extreme weather events in both the winter and summer further illustrate the importance of a balanced and reliable grid. During the summer in Minnkota's service area, MISO currently has the capacity to serve its projected summer needs if wind generation performs as anticipated.[4] However, loss of coal resources and the reliability issues of

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(June 30, 2023), https://www.bea.gov/sites/default/files/2023-06/stgdppi1q23.pdf

3 https://www.statista.com/statistics/1065144/north-dakota-real-gdp-by-industry/

4 https://cdn.misoenergy.org/2023%20Summer%20Resource%20Assessment628978.pdf

CCS would put further pressure on wind in a reliability crisis. Loss of diversification of generation resources and dependence on wind exacerbates the risk of under-generation during the extreme cold winter, hot summer, and other weather events.

71. *Costs of Reliability Events to Minnkota and its Members*. During reliability events, the costs to purchase power skyrocket. Minnkota would be exposed to these extreme costs if Minnkota could not meet its own generation needs with its own generation assets.

72. *Other Damages from Reliability Events.* The North Dakota Reliability Study highlights the dramatic repercussions from the loss of units due to the Final Rule. Minnkota would anticipate a loss of jobs at the Young Station. Minnkota employs 200 people in the vicinity of Center, North Dakota. In addition, many subcontractors provide services to the plant on a regular basis. The nearby BNI Coal mine would be impacted or possibly close because it sells lignite to the Young Station. On information and belief, BNI employs approximately 178 persons at the mine. In total, the direct cost to the community from the loss of employment would be staggering.

Impacts from the loss of jobs in the area would have a ripple effect on ancillary industries, such as nearby service stations, reduced demand for customer services, and the social and psychological impacts of job loss on the affected individuals and their families. Premature retirement of units results in irreversible harm that economically damages Minnkota and impacts the entire region.

73. The interruption of power delivery from a grid failure would cause damage to public health. North Dakotans rely on electricity to heat their homes during the extreme winter temperatures of the long winter season. Affordable and consistent power allows for medical providers to provide essential services to the elderly, infirm, and to vulnerable individuals with chronic health conditions. Evidence from grid failures in other areas of the country in winter storms Uri and Elliott show the documented health impacts and morbidity caused by those events. The Final Rule places the portion of the grid serving North Dakota in serious jeopardy of failure and resulting consequences.

74. EPA failed to adequately account for the costs due to a grid failure in the rulemaking. In its service area, Minnkota would anticipate that grid failures would cause end users to suffer economic and real damages such as food spoilage, property damage, lost labor productivity, and loss of life. The North Dakota Reliability Study discusses these damages in more detail in Section D (Modeling Results).

ABSENT A STAY, MINNKOTA WILL SUFFER IMMEDIATE IRREPARABLE HARM

75. Minnkota is harmed by the Final Rule with respect to any alternative the cooperative would pursue to continue to provide reliable and affordable power to its member cooperatives. These options are: (1) Compliance with the Long-Term coal category for Unit 1 and Unit 2; or (2) Retirement of the Milton R. Young Station.

Compliance with the Long-Term Coal Category.

76. The Final Rule would require Minnkota to immediately identify a compliance alternative for the remaining untreated flue gas at the Young Station. To accomplish this task through CCS, Minnkota must immediately begin taking steps to determine the breadth of the impact to the current

design of Project Tundra and any alternatives. These steps include engineering studies, design studies, and purchase contracts. All of that must happen soon, because each increment of delay puts compliance with the Final Rule even further out of reach. Working backwards from a 2032 compliance date, Minnkota is already significantly behind schedule. Designing the current scale of CCS for Project Tundra took almost a decade. Yet the Final Rule requires Minnkota to update that design with a new, expanded CCS system *and* bring it into operation within about half that time.

77. The expected costs involved in complying with the Long-Term Subcategory would be substantial. The additional development costs alone would be projected between $10-40 million. Further studies would need to be conducted to identify an estimate for the remainder of the project. It is very uncertain whether Minnkota could secure additional project partners, funds, or loans to allow for this expenditure.

78. Unlike larger IOU systems, Minnkota does not have investors from which to raise money. Rather, Minnkota often relies upon USDA RUS financing for large capital projects. The process of securing financing

through the RUS requires additional time for completion of environmental review under NEPA. As a small entity cooperative, Minnkota is less nimble at procuring financing and has fewer resources available to meet demand.

Retirement of the Milton R. Young Station.

79. Minnkota has *already* made significant capital expenditures for Project Tundra. As previously mentioned, Project Tundra hinges on the ability of the Young Station to comply with the Final Rule. The Final Rule jeopardizes this capability. If Project Tundra fails as a result, Minnkota, along with its partners, the State of North Dakota, and the Department of Energy, have expended over <u>$90 million</u> towards project development as of March 31, 2024. Those costs are not recoverable, and similar costs will only continue to accrue and accelerate over the next several years of litigation—unless the Final Rule is stayed. Minnkota has spent project costs and will continue expending additional costs during the pendency of the litigation, which, without commercial operation of the project, will not be recoverable.

80. Minnkota must evaluate all alternative baseload generation, including natural gas. But even today's state-of-the-art natural gas combined

cycle units ("Combined Cycles") cannot achieve the 90% capture of CCS that the Final Rule demands. Even if those units could achieve 90% CCS, constructing in-kind MW generation to replace the Young Station would cost approximately $1 billion. That estimate does not include land, water rights, financing fees, escalation, tax, or insurance. To bring that amount of generation into its portfolio by the Final Rule's cliff, Minnkota does not have sufficient time.

81. As a mine-mouth facility, Minnkota would incur costs associated with the BNI mine. These costs include mine closure and reclamation.

82. A summary of the costs of retirement of the Young Station and the construction of natural gas replacement power are:

Activity	**Cost**	**Basis**
Expenditures lost from Project Tundra	$30M	Accounting
Stranded Debt from the Young Station	Unit 1 ($158.5M); Unit 2 ($70.7M) = total $229.2 million upon January 1, 2032	Accounting
Construction of a New Gas Line to Young Station	$60 M($2M per mile)	Vendor estimates

Construction of a Natural Gas Combined Cycle Unit*	$1 billion, which includes the capital cost at $1400 kW and interconnection costs to MISO	Vendor estimates
BNI Mine Reclamation costs	$200-220 M	Accounting
Stranded Debt from the BNI Mine	60-70 M	Accounting
TOTAL	**$1.58-1.61 billion**	

*These costs do not include the cost of constructing or retrofitting a capture facility for the flue gas from a gas unit.

**These costs do not include the cost of shuttering the Young Station.

83. If Minnkota were unable to replace the megawatts from the Young Station prior to the compliance date for the Final Rule of 2032, Minnkota would be faced with increased exposure to market volatility. The costs of purchasing power off the MISO market may expose Minnkota's membership to a current cap of $3,500 per MWh, which could eliminate the entire annual value of the Young Station's generation in less than 4 days.

84. Regardless of which compliance pathway it chooses, Minnkota will need to secure reliable and dispatchable replacement power as result of the Final Rule. Non-dispatchable renewable energy sources (such as wind and solar) cannot satisfy that demand due to their intermittent nature.

85. *Immediate costs to Minnkota's members and consumers.* As a cooperative, Minnkota will be faced with all these near-term costs. Minnkota's members—and ultimately to the rural end users who depend on Minnkota to keep their lights and heat on will bear the costs of the Final Rule.

86. These costs are not recoverable. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded. Legally binding retirement promises cannot be undone.

87. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of the State Petitioners' Petition for Review. At best, Minnkota expects that process to take *at least* 2-3 years. But the Final Rule's compliance deadlines do not give Minnkota any time to spare. On the contrary, haste is of the essence, for several reasons.

88. In sum, if the Final Rule remains in effect while challenges to the Rule are pending, Minnkota will have no choice but to incur significant unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

*   *   *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 10th day of May, 2024, in ___Washington, DC .

Robert McLennan

Appendix 8

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION,	)	
Petitioner,	)	
v.	)	Case No. 24-1122
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,	)	
Respondents.	)	

DECLARATION OF DAVID J. TUDOR

I, David J. Tudor, declare as follows:

1. My name is David J. Tudor. I am the CEO & General Manager at Associated Electric Cooperative Inc. ("Associated Electric"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have over 40 years of experience in the energy industry with public and private corporations and cooperatives. I served on the board of

directors of Western Midstream (NYSE: WES) and currently serve on the board of directors of Electric Power Research Institute ("EPRI"), National Renewables Cooperative Organization ("NRCO"), and Woodway Energy Infrastructure. I have been employed at Associated Electric since 2016. I hold a bachelor's degree in Accounting from Lipscomb University.

3. As CEO & General Manager at Associated Electric, I am ultimately responsible for providing Associated Electric's member systems with an economical and reliable power supply and support services. I have broad latitude authorized by the policies of the Board of Directors to develop and implement strategies and tactics that achieve Board objectives and ensure the long-term success of Associated Electric. I am responsible for directing the generation and transmission of electricity to meet member system demand; informing and involving member owners; ensuring strong financial planning and flexibility; ensuring compliance with all applicable industry state and federal laws and regulations; identifying and managing the risks of Associated Electric's business; developing and maintaining

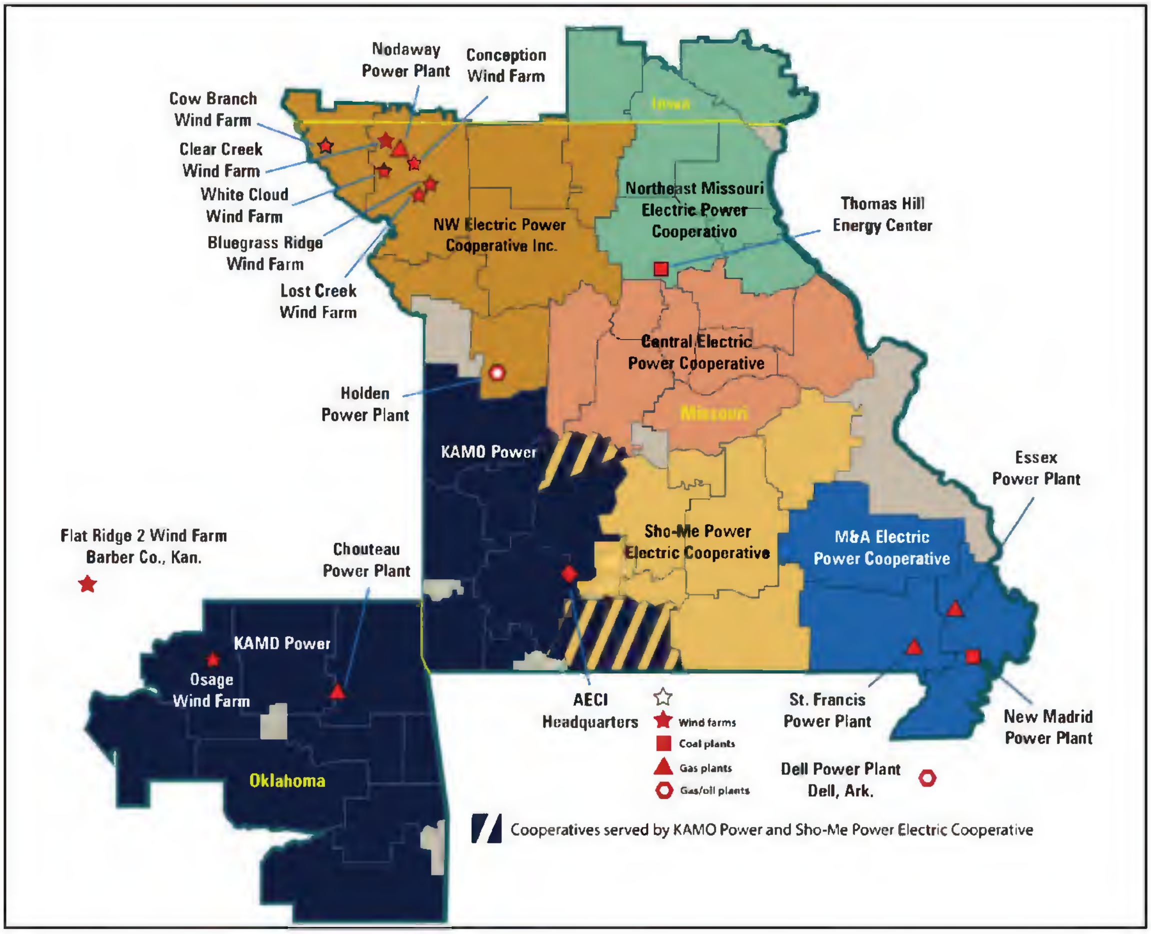
strategic alliances; and representing Associated Electric on a local, regional and national level.

4. Associated Electric is a member of the National Rural Electric Cooperative Association ("NRECA") and is also a member of the Midwest Ozone Group ("MOG"). This declaration is submitted in support of the litigation challenging EPA's final rule 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*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

5. I am familiar with Associated Electric's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect Associated Electric as well as its suppliers, members, consumers, and employees.

6. For over 60 years, Associated Electric has operated as not-for-profit generation-and-transmission cooperative ("G&T") that provides reliable, wholesale power generation and high-voltage transmission to our transmission cooperative member-owners. Those member-owners supply power to 51 local electric cooperatives in Missouri, Iowa, and Oklahoma, collectively serving about 935,000 homes, farms, schools, and businesses.

7. Associated Electric uses a mix of generating resources and technologies to make sure it can deliver electricity at the lowest cost possible to its member transmission cooperatives, and Associated Electric balances that mission with environmental stewardship. Associated Electric uses the lowest-cost resources first—typically hydropower when it is available, then coal, natural gas, and wind energy. The figure below illustrates Associated Electric's service area and generation portfolio.



8. Associated Electric owns, operates, and depends on five coal-fired electric generating units ("affected EGUs") that the Final Rule regulates, and that thus must comply with the Final Rule's stringent new standards for coal-fired steam units. These affected EGUs have remaining useful lives that will be significantly shortened under the Final Rule. Replacing them, and complying with the Final Rule, is expected to have an

approximate cost of **more than $3 billion primarily representing new capital spend**. As a member-owned cooperative, Associated Electric will be forced to pass those costs on to its consumers.

OVERVIEW OF THE FINAL RULE

9. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam units, under Section 111(d). 89 Fed. Reg. at 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* at 39902. Both existing and new units must meet emissions limits equal to what EPA says 90% carbon-capture-and-sequestration can achieve. Existing units that cannot achieve this must shut down. New units that cannot achieve this must drastically reduce their output of electricity.

10. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* To be effective, these commitments

must be included in State plans, which are due to EPA in 24 months. *Id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

11. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

12. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent"—*i.e.*, transforming a coal

unit into one that combusts both coal and natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

13. Third, units that make a federally enforceable commitment to permanently cease operating before January 1, 2032, have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

14. *New gas-fired combustion turbine units*. For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* at 39908.

15. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* at 39917. "Intermediate load" units (those that sell 20-40% of their potential electric output) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.*

"Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO_2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology

IMPACT OF THE FINAL RULE ON ASSOCIATED ELECTRIC

16. Associated Electric depends on some coal-fired power to deliver reliable baseload generation, serve as an economic hedge to the volatile natural gas market, and ensure capacity in peak seasons and in hours when intermittent renewables such as wind and solar are unreliable. The Final Rule will therefore have significant costs for Associated Electric. These costs will ultimately fall on the members in Associated Electric's service area—at least 40 percent of whom live in persistent poverty conditions, and all of whom depend on reliable generation to keep the lights on and to heat and cool their homes. These increased costs also disproportionately impact

Associated Electric's membership due to lower member line density/mile in the rural areas served compared to urban areas where cost impacts are blunted by the presence of more customers/mile.

17. Associated Electric owns and operates the Thomas Hill Energy Center in Clifton Hill, Missouri ("Thomas Hill"), which consists of three coal-fired units that together have the capacity to generate 1150 MW of power. Associated Electric employs about 208 people at Thomas Hill. Thomas Hill has received national recognition for its efficiency and successful conversion to low-sulfur coal that reduced sulfur dioxide emissions 90 percent. Associated Electric has also achieved a systemwide nitrogen oxides emission rate reduction of up to 90 percent through its $423 million environmental controls project at Thomas Hill to comply with air quality rules. Associated Electric was first to reduce mercury emissions up to 80 percent with use of refined coal in cyclone Units 1 and 2. Associated Electric added a refined coal system on Unit 3 to further reduce mercury emissions in 2015. Using refined coal is part of Associated Electric's compliance with EPA's Mercury and Air Toxics Standards.

18. Associated Electric also owns and operates the New Madrid Power Plant in Marston, Missouri ("New Madrid"), which consists of two coal-fired units that together have the capacity to generate 1200 MW of power. Associated Electric employs about 161 people at New Madrid.

19. These five affected EGUs—three at Thomas Hill, and two at New Madrid—are critical to Associated Electric's mission of providing an affordable and reliable supply of power to member systems. The remaining depreciable life of these EGUs extends beyond into the 2050s, and their remaining useful life extends far beyond that. Depreciable life is an accounting metric for allocating costs, not a measure of how long a plant can reasonably be expected to remain useful. Because these affected EGUs have such long depreciable and useful lives, Associated Electric has planned to keep these EGUs in service indefinitely, and for as long as they can contribute to Associated Electric's mission of providing affordable and reliable power to members.

20. *CCS is not achievable at Thomas Hill or New Madrid*. The Final Rule allows affected EGUs to remain in operation beyond 2040 only if they can

achieve 90% CCS by 2030. That is not possible at Thomas Hill or New Madrid. The technology to reliably achieve 90% CCS is not available. And even the young and still-developing technology that is available is unreliable and is prohibitively expensive (and cannot achieve 90% capture in any event). But technological issues are not the only thing preventing Associated Electric from relying on the 90% CCS compliance pathway. Even if 90% of CO_2 could be captured from Thomas Hill or New Madrid, that CO_2 would need to be transported for storage. Transportation requires a pipeline. But no CO_2 pipeline exists near Thomas Hill or New Madrid. Nor is it realistic to expect such a pipeline to come into existence before 2030. Permitting, siting, design, and construction will all take much longer than the few years that the Final Rule allows. Furthermore, even once CO_2 is transported, it must be stored. But no storage sites near Associated Electric currently exist, nor are any sites expected to be permitted before 2030. Therefore, the "long term" compliance pathway is not an option for Thomas Hill or New Madrid.

21. Because 90% CCS is not possible, the Final Rule forces Thomas Hill and New Madrid to make a federally enforceable retirement

commitment, either by using the medium-term subcategory, or by claiming an applicability exemption. In order to continue fulfilling its mission, Associated Electric must avoid premature retirement of its EGUs. Therefore, the subcategory that is most likely to be the least detrimental option is to designate Thomas Hill and New Madrid as "medium-term" units. That election requires Associated Electric to make a legally binding commitment (by mid-2026) to shut down Thomas Hill and New Madrid by 2038, and to achieve 40% natural gas co-firing at Thomas Hill and New Madrid by the end of 2029. To achieve that, Associated Electric must immediately begin spending money across a variety of expense categories.

22. *Equipment costs*. Thomas Hill and New Madrid will need to be retrofitted with new equipment that will allow them to co-fire with natural gas. This new equipment (*e.g.*, natural gas burners, modifications to the plant controls systems, and furnace reinforcement) is available only from a limited number of original equipment manufacturers, all of whom will be facing an increase in demand from other affected EGUs across the country. Associated

Electric, with help from its engineering consultants, estimates that the total capital costs to convert all five of its coal-fired units will be $116,460,000.

23. *Replacement power costs*. The units at Thomas Hill and New Madrid are designed to burn coal. Converting these units to allow for natural-gas co-firing will reduce the units' efficiency from its 2350 MW current max output. It is currently unknown whether a 40% co-firing rate is even technically possible at these units. Even if it is possible, the corresponding efficiency reductions will require Associated Electric to find replacement power—either via market purchases or by building new generation. Either strategy has large costs.

24. If the Final Rule takes effect, electric markets will be highly constrained, as generators across the country will see reductions in their portfolios. Thus, the most cost-efficient option to address reduced efficiency of Thomas Hill and New Madrid is to construct new generation. Yet the Final Rule also imposes stringent requirements for new baseload EGUs—all of which must achieve 90% CCS. That level of CCS is not possible for new EGUs, which would be composed of natural gas units rather than coal-fired

units. Nor can Associated Electric depend on renewables for baseload generation. Thus, for new generation that is needed as a result of the Final Rule, Associated Electric's only viable option is to use a large number of low-capacity combustion turbines ("CTs") all running at a capacity factor of 20% or less for its replacement power needs. In the near term, these needs include replacement power to offset the decreases in efficiency that will come with co-firing. And beyond that, once the affected EGUs follow through on the retirement promises that the Final Rule compels, Associated Electric will need to find replacement power for the affected EGUs themselves, which currently supply 2350 MW of coal that is needed to reliably run the system. For replacement-power generation to begin being available by 2030, when co-firing must begin, Associated Electric must start spending money now for planning, engineering design, siting, permitting, and construction—all in a growingly supply-constricted market for this kind of generation.

25. *Transport costs*. Associated Electric cannot co-fire natural gas at Thomas Hill or New Madrid unless there is a way for natural gas to be transported to the EGUs at those locations. Even standing alone, this is a

massive expense. On a simple map, New Madrid appears close to existing natural gas pipeline infrastructure. But just because a pipeline is close, that does not mean that the pipeline has available capacity or pressure for new connections. Indeed, Associated Electric has determined that the closest pipeline with capacity and pressure to support New Madrid is located 46 miles away, with an estimated capital cost of **$243,800,00** to connect to the plant. And for Thomas Hill facility, the closest gas line with capacity is 14 miles away, with an estimated capital cost of **$52,200,000** to connect.

26. Given the long lead times for construction projects, a pipeline operator must begin engineering design, permitting, siting, procurement, and construction immediately merely to have a chance to make natural gas available at Thomas Hill and New Madrid in time for the Final Rule's 2030 deadline. But no operator is likely to take all those steps without a substantial, up-front commitment from Associated Electric—either in the form of a capital contribution to the pipeline project, or in the form of a long-term (20-30 year) supply contract. Even if Associated Electric identified an operator and agreed to such terms, there is no guarantee that such a pipeline

would actually be completed. Permitting, construction delays, right-of-way issues, and myriad other factors could block the pipeline or could delay it beyond the Final Rule's compliance deadlines. If that happened, Associated Electric's investments in equipment costs would be completely lost, and Thomas Hill or New Madrid could need to shut down.

27. *Permitting costs*. Converting the affected EGUs to natural gas co-firing will also require Associated Electric to obtain new permits, including Title V, Acid Rain, and National Pollutant Discharge Elimination System construction permits that would be transitioned into operating permits. But these permits are expensive and time consuming, and their issuance is also subject to judicial review. In order to have permitting in place when necessary, Associated Electric must immediately begin the permitting process for Thomas Hill and New Madrid.

ABSENT A STAY, ASSOCIATED ELECTRIC WILL SUFFER IMMEDIATE IRREPARABLE HARM

28. *Immediate costs for retrofits*. Achieving 40% natural gas co-firing Thomas Hill and New Madrid by 2030 requires Associated Electric to immediately begin taking steps to procure new equipment. Costs associated

with these steps include engineering studies, design studies, and purchase contracts. All of that must happen soon, because each increment of delay puts compliance with the Final Rule even further out of reach. Once the equipment is purchased and received, it must be installed and tested. Then Associated Electric must troubleshoot to ensure that the equipment is operating efficiently and reliably. Working backwards from a 2030 compliance date, the purchasing process should have already begun.

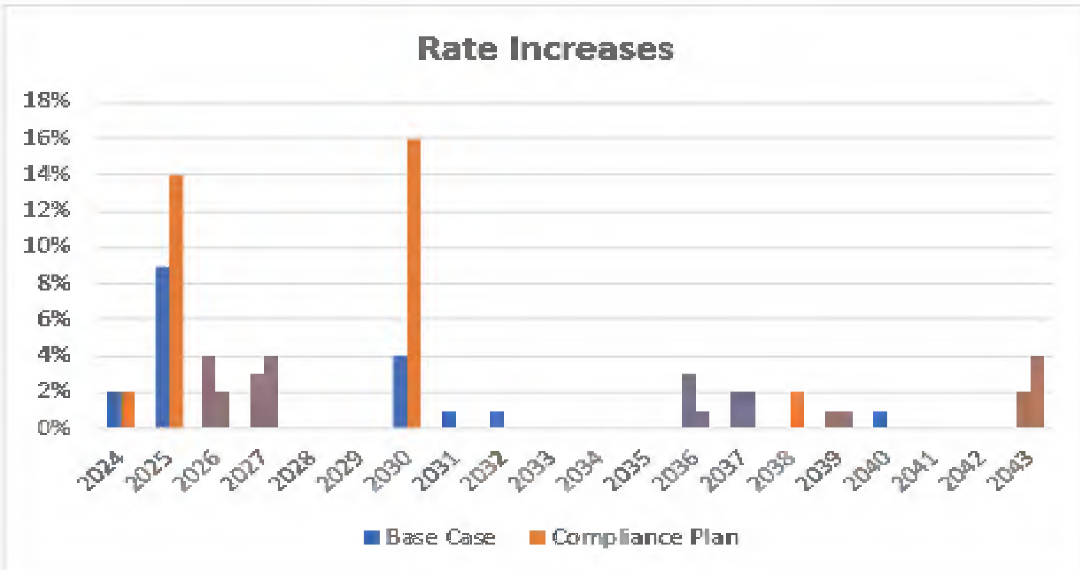
29. *Immediate pipeline costs*. To transport natural gas to Thomas Hill and New Madrid, securing the right-of-way ("ROW"), surveying, and permitting can be expected to take several years (at minimum). Construction is likely to take at least another two years—and longer if there is litigation or challenges to the permits. Given the recent history of vociferous opposition to natural gas pipelines, significant extra time must be built into this schedule to account for litigation and other opposition. Even when natural gas service is in close proximity, the cost of connecting to a suitable service line can be prohibitively expensive and is unlikely to be available by 2030. Associated Electric must immediately begin making significant capital

expenditures in order to help bring these resources into existence by the 2030 deadline.

30. *Immediate replacement power costs*. Associated Electric would need to replace a significant amount of baseload, dispatchable generation as a result of the Final Rule. Renewable energy sources (such as wind and solar) cannot satisfy that demand. Land acquisitions alone would be cost-prohibitive. But even ignoring that, renewables are an intermittent resource that are available only *some* of the time. Associated Electric cannot rely on renewables for all of its baseload generation—which must be available *all* of the time. Placing total dependence on renewables is a recipe for disaster if people need power to heat their homes at nighttime (no solar) or in calm conditions (no wind). Thus, for replacement power, Associated Electric must immediately begin the process of procuring, permitting, and installing new natural gas combustion turbines to replace the lost output from 40% co-firing.

31. *Immediate costs to Associated Electric's members and consumers.* All of these near-term costs will immediately begin flowing to Associated

Electric's distribution cooperative members, and ultimately to their consumer-members at the end of the line.



32. The figure above shows the immediate impact of the Final Rule. Even by as early as next year, the rates that Associated Electric charges are expected to increase more than 50% above the increase that would be expected in a "base case" scenario (one which assumes the Final Rule is not applicable). That expected increase is due directly to the massive costs that the Final Rule creates. As a cooperative, Associated Electric must pass these costs on to its members.

33. These costs are not recoverable. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded. Legally binding retirement promises cannot be undone.

34. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of this litigation. At best, Associated Electric expects that process to take *at least* 2-3 years. But the Final Rule's compliance deadlines do not give Associated Electric time to spare. For one thing, the Final Rule's one-year compliance extension mechanism is available only if Associated Electric "has made all reasonable efforts to achieve timely compliance" and "has acted consistent with achieving timely compliance." 89 Fed. Reg. 607. In other words, Associated Electric must act *now* in order to preserve its ability to claim the Final Rule's compliance extension mechanism (assuming that extension is even included in the State plans that will govern Associated Electric). For numerous other reasons, too, haste is of the essence.

35. *Supply chain delays*. Original equipment manufacturers will soon be flooded with new purchase orders from EGUs all across the country.

Equipment for natural gas co-firing is highly specialized and site-specific; significant engineering, design, and permitting work is required ahead of placing equipment orders and executing natural gas contracts; and time is needed for installation and commissioning. Schedules for these types of projects are already 3-4 years long. Those delays will only grow if the Final Rule takes effect. This creates a "race" among EGUs that need to order new equipment, each one hoping to be nearer the front of the queue. Associated Electric is not immune to that dynamic. Thus, Associated Electric has no choice but to begin purchasing equipment before the courts can adjudicate the challenges to the Final Rule on the merits.

36. *Labor market delays*. Complying with the Final Rule will require Associated Electric to hire consultants, engineers, attorneys, and other professionals to manage the vast amounts of design, modeling, permitting, and other work required under the Final Rule. Yet these markets are also subject to the laws of supply and demand. As EGUs across the country rush to hire the same professionals, prices will increase. Accordingly, EGUs must

move early—not only to insulate themselves from price pressures, but also in attempt to ensure that the needed professionals are even available.

37. *Financing delays*. On top of the delays that EPA has already discussed in the Final Rule, Associated Electric must factor in financing delays. The Final Rule will require Associated Electric to make major capital investments in replacement power. The federal Rural Utilities Service ("RUS") provides financing for generation construction, with the mission of electrifying and maintaining critical infrastructure in rural America. Obtaining RUS financing is a years-long, multi-step process which, prior to construction, requires preparation of initial scoping, project justification, confirming cost estimates, design, and operational specifications. RUS must approve the Work Plan but the compliance timeframe in the Final Rule creates serious doubt that these normal processes can be navigated in the time provided.

38. *NEPA delays*. RUS financing also requires compliance with the National Environmental Policy Act ("NEPA"), which adds time at the beginning of a large project, and which is subject to judicial review. The

environmental review requirements are set forth by NEPA, which require all federal agency actions or approvals go through a standardized environmental review process to evaluate what effect their proposed actions (*i.e.*, projects) would have on the environment. Environmental reviews require development of Environmental Reports ("ERs"), Environmental Assessments ("EAs"), or Environmental Impact Statements ("EISs") depending on the complexity/scale of the project. The White House Council on Environmental Quality recently issued a new NEPA "Phase 2 Rule," which makes extensive regulatory changes and layers on numerous new requirements that will inject additional uncertainty and delays into the NEPA process. Still, even without the latest regulations, the environmental review process and timelines depend upon the scope of the project and ultimately upon what project documents RUS will request that the cooperative submit. It is impossible to know in advance exactly what these requests will be, which again incentivizes Associated Electric to act quickly.

39. Associated Electric must wait for the conclusion of RUS's environmental review *before* taking any major action on projects or RUS

releases funds. While other financing options may be available for certain types of projects, the interest rates are significantly higher. Associated Electric is a cooperative, and its consumers are in rural communities, many of which are disadvantaged. Both are very sensitive to rate increases. Associated Electric regularly depends on RUS to help finance environmental compliance and other projects. This process alone can take up to two years—and even longer.

40. In sum, if the Final Rule remains in effect while this litigation is pending, Associated Electric will have no choice but to incur significant unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

*   *   *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 10th day of May, 2024, in Carmel, IN.

David J. Tudor

Appendix 9

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION,	)	
Petitioner,	)	
v.	)	Case No. 24-1122
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al*.,	)	
Respondents.	)	

DECLARATION OF VERNON HASTEN

I, Vernon "Buddy" Hasten, declare as follows:

1. My name is Vernon Hasten. I am the President and Chief Executive Officer ("CEO") at Arkansas Electric Cooperative Corporation ("Arkansas Electric"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have over 38 years of experience in electricity generation and 17 years of experience in the electric public utility sector. I have been

employed at Arkansas Electric since 2019. I hold a bachelor's degree in electrical engineering from Auburn University, as well as twenty years of service in the United States Navy as an enlisted nuclear trained operator with 15 of those years serving as a commissioned officer serving aboard nuclear-powered submarines. As President and CEO, I am responsible for overseeing all aspects of Arkansas Electric, including planning and market operations, and power production and delivery.

3. Arkansas Electric is a member of the National Rural Electric Cooperative Association ("NRECA"). This declaration is submitted in support of NRECA's Petition for Review and Motion for Stay of EPA's final rule 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*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

4. I am familiar with Arkansas Electric's operations, including generation and transmission, regulatory compliance, workforce

management, and electric markets in general. I am also familiar with the Final Rule, and I am familiar with how the Final Rule will affect Arkansas Electric as well as its suppliers, members, consumers, and employees.

5. Arkansas Electric is a not-for-profit generation and transmission ("G&T") electric cooperative that provides power for more than 1.3 million Arkansans served by Arkansas' 17 electric distribution cooperatives. Arkansas Electric was created in 1949 to provide its member-owners with a reliable, affordable, and responsible power supply. The mission of Arkansas Electric is to provide safe, affordable electric power and related services reliably and responsibly by assisting its members in improving the quality of life in the areas they serve. Arkansas Electric strives to achieve these goals at the lowest possible cost consistent with sound business practices.

6. Arkansas Electric takes a balanced approach to providing power to the State of Arkansas and, on an energy basis, nearly 20 percent of the power Arkansas Electric's members receive comes from hydro, wind, solar and other non-fossil resources. Collectively, the electric cooperatives in

Arkansas provide this diverse and reliable generation mix to more than 600,000 homes, farms, and businesses in Arkansas.

7. Arkansas Electric owns or has power purchase agreements for a total of 4,389 megawatts ("MW") of generation capacity. Arkansas Electric's generation plants include two natural gas / oil-based plants, three hydroelectric generating stations, four natural gas plants, and a utility scale solar facility. Arkansas Electric co-owns four coal-based power plants in Arkansas. In addition to generation assets it owns, Arkansas Electric has power purchase agreements for additional energy resources including hydroelectric energy from the Southwestern Power Administration, battery energy, wind energy and solar energy (together, the total amount of these resources represents more than 18 percent of the cooperative's generation and energy portfolio).

8. Arkansas Electric is a co-owner of two coal-fired electric generating units ("affected EGUs") that the Final Rule regulates, and that thus must comply with the Final Rule's stringent new standards for coal-fired steam units. These affected EGUs have remaining useful lives that will

be significantly shortened under the Final Rule. Replacing the generation from these units, and complying with the Final Rule, is expected to have an approximate cost of up to $470 million. As a member-owned cooperative, Arkansas Electric will be forced to pass those costs on to its consumers.

OVERVIEW OF THE FINAL RULE

9. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam electric generating units, under Section 111(d). 89 Fed. Reg. 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* 39902. Both types of units must meet emissions limits equal to what EPA believes 90% carbon-capture-and-sequestration can achieve. Existing coal-fired units that cannot achieve this must shut down. New gas-fired combustion-turbine units that cannot achieve this must drastically limit their output of electricity.

10. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement

date that a unit has committed to. *See id.* For purposes of implementing these subcategorizations for a particular unit, EPA recognizes only those retirement commitments that are made "federally enforceable" via inclusion in a State plan. *Id.* 40000. State plans are due to EPA in 24 months. *Id.* 39997.

11. The first (and default) subcategory is for "long-term" units, which EPA defines as units that "intend to operate past January 1, 2039." *Id.* 39801. EPA says that the best system for this subcategory is CCS that captures 90% of the CO_2 from a unit. *Id.* 39845. This system begins with the design, engineering, and installation of CO_2 capture technology. *Id.* 39846. Then the captured CO_2 must be transported (usually via pipeline) to a site that can permanently sequester it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in "June 2024." *Id.* 39874. And the Rule requires unit operators to complete that work before January 1, 2032. *Id.* 39801.

12. The second subcategory is for "medium term" units: those that commit "to permanently cease operations" sometime "after December 31, 2031" but "before January 1, 2039." *Id.* 39841; *see id.* 39958. EPA says that best

system for this subcategory is "[n]atural gas co-firing at 40 percent." *Id.* 39801. That means transforming a coal unit into a unit that combusts both coal and natural gas. *See id.* Just "[a]s in the timeline for CCS," EPA "assumes" that "work" toward co-firing will begin in June 2024. *Id.* 39893. And the Rule requires medium-term unit operators to complete that work before January 1, 2030. *Id.* 39845.

13. Third, the Rule establishes an "applicability exemption" for units that commit "to permanently cease operation before January 1, 2032." *Id.* 39841. These units "are not regulated by" the Rule. *Id.* 39843. However, if such a unit then "continues to operate past [that date], then it is no longer exempt," *id.*, putting the unit "in violation of" the State plan and the Clean Air Act, *id.* 39991.

14. *New gas-fired combustion turbine units.* For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* 39908. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply

with a standard of performance based on "lower-emitting fuels." *Id.* 39917. "Intermediate load" units (those that sell 20-40%) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.* "Base load" units (those sell more than 40%) must comply with a "multi-phase standard of performance." *Id.* 39923. Phase I is "based on the performance of a highly efficient combined cycle turbine" and has "an immediate compliance date." *Id.* 39903. Phase II is based on 90% CCS and has "a compliance date of January 1, 2032." *Id.*

IMPACT OF THE FINAL RULE ON ARKANSAS ELECTRIC

15. Arkansas Electric depends on some coal-fired power to deliver reliable baseload generation, serve as an economic hedge to the volatile natural gas market, and ensure capacity in peak seasons when renewables such as wind and solar are unavailable. While wind and solar play important roles in a balanced energy portfolio, they are intermittent and weather-dependent; they only generate when the sun shines and the wind blows. During the critical period of mid-February 2021, including during Winter Storm Uri, wind and solar were challenged. Arkansas Electric has 474 MW

of wind from five wind plants in Oklahoma and Kansas, and there were 58 hours during this time frame when all five of these wind plants were producing no energy. Arkansas Electric's winter peaks (which have recently exceeded summer peaks) consistently occur during the early morning hours, either at hours ending 7 a.m. or 8 a.m. Solar provides minimal generation during these early morning winter hours. Arkansas Electric's highest all-time peak occurred on December 23, 2022, during Winter Storm Elliott, hour ending 8 a.m. Arkansas Electric has solar agreements from 15 solar facilities throughout Arkansas. The generation from these solar facilities was only 6% of installed capacity during this all-time peak hour. As such, Arkansas Electric must rely on baseload generation to meet member needs during these dark, cold hours.

16. The Final Rule will have immense costs for Arkansas Electric. These costs will ultimately fall on the consumers in Arkansas Electric's service area. Many of those consumers live in persistent poverty conditions, and all of them depend on Arkansas Electric to provide reliable power for vital, basic necessities such as heating and cooling their homes.

17. Arkansas Electric owns fifty percent of the Flint Creek Power Plant in Benton County, Arkansas ("Flint Creek"), which consists of a single coal-fired unit that can produce up to 528 MW of electricity. And Arkansas Electric owns 73 MW from the John W. Turk, Jr. Power Plant in Fulton, Arkansas ("Turk"). The Turk Plant was commissioned in 2012 and consists of a single coal-fired unit that can produce up to 624 MW of electricity.

18. These affected EGUs are critical to Arkansas Electric's mission of providing an affordable and reliable supply of power to member systems. The remaining useful life of these EGUs extends far into the future, and Arkansas Electric has no plans to retire these units. Instead, Arkansas Electric has long expected that these EGUs will remain in service for as long as they can contribute to Arkansas Electric's mission of providing affordable and reliable power to members.

19. The CCS pathway is not possible at Flint Creek or Turk. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if they can achieve 90% CCS by 2032. That is not possible at Flint Creek or Turk. The technology to reliably achieve 90% CCS is not available. And even if the

young and still-developing technology was available, current experimental projects have proven that it is unreliable and prohibitively expensive (and cannot achieve 90% capture in any event).

20. Technological issues are not the only thing preventing Arkansas Electric from relying on the 90% CCS compliance pathway. Even if 90% of CO_2 could be captured from Flint Creek or Turk, that CO_2 would need to be transported for storage. Transportation requires a pipeline. But no CO_2 pipeline exists near Flint Creek or Turk. It is not realistic that such pipelines will come online before 2032. Initial research indicates the closest CO_2 pipelines are along the Gulf Coast of Louisiana or in central Oklahoma – distances well over 200 miles from either Flint Creek or Turk. Further, these existing CO_2 pipelines are not guaranteed to have the capacity for additional transportation.

21. Arkansas Electric is an electric cooperative, not a CO_2 pipeline operator. Even for an experienced operator, permitting, siting, securing right-of-way, overcoming local and landowner resistance, navigating protracted litigation, design, equipment procurement, and construction

would each and collectively take much longer than the few years that the Final Rule allows. Furthermore, even once CO_2 is transported, it must be stored. But no storage sites near Arkansas Electric currently exist, nor are any sites expected to be permitted before 2032. Therefore, the "long-term" compliance pathway is not an option for Flint Creek or Turk.

22. The co-firing pathway is not possible at Flint Creek. The Final Rule allows affected EGUs to remain in operation through 2038 (but no further) only if they can achieve 40% co-firing with natural gas by 2030. That is not possible at Flint Creek. Transporting natural gas to Flint Creek would require at minimum a 70-mile pipeline. Here again, Arkansas Electric is not a pipeline operator. And even if an experienced operator were interested in constructing a pipeline to Flint Creek, permitting, siting, securing right-of-way, overcoming local and landowner resistance, navigating protracted litigation, design, equipment procurement, and construction would still take much longer than the few years that the Final Rule allows (just like with CO_2 pipelines). Further, investing in retrofits to allow co-firing at Flint Creek does not make economic sense if it will also be forced to retire by January 1, 2039.

23. Co-firing with natural gas at Turk may be feasible, but not by the Rule's compliance deadline, and it may be economically prohibitive in any event. There are existing natural gas transmission lines within a few miles of Turk, so co-firing with natural gas may theoretically be an option. However, the investment to install a new pipeline to reach the transmission pipelines and modify the boiler to co-fire with natural gas may be economically prohibitive if Turk will be forced to retire by January 1, 2039 under this compliance option.

24. Thus, retirement by the end of 2031 is the only option for Flint Creek and Turk. Because the "long-term" and "medium-term" pathways are closed for Flint Creek and likely closed for Turk, the Final Rule forces Flint Creek and Turk to take steps to claim the "applicability exemption" in order to continue providing power for as long as possible. But this strategy requires operators of affected EGUs to make a federally enforceable commitment to retire those EGUs by the end of 2031. That commitment also must be made to the State of Arkansas in time for Arkansas to incorporate it into its state plan, subject the plan to state notice, comment, and revision,

and submit that plan within 24 months of the Rule's publication. In turn, this requires Arkansas Electric to immediately begin spending money across a variety of expense categories in anticipation of the retirement and replacement of these assets.

25. By retiring Flint Creek and Turk, Arkansas Electric will be losing approximately 335 MW of reliable, baseload generation. That reduction will require Arkansas Electric to find replacement power—either via market purchases or by building new generation. Either strategy has large costs. If the Final Rule takes effect, electric markets will be highly constrained, as generators across the country will see reductions in their portfolios.

26. The most cost-effective option to address reduced efficiency of Flint Creek and Turk is to construct new generation. Yet the Final Rule also imposes stringent requirements for new baseload EGUs—all of which must achieve 90% CCS. That level of CCS is not possible for new EGUs, which would be composed of natural gas units rather than coal-fired units. Nor can Arkansas Electric depend on renewables for baseload, 24/7 generation.

27. For new generation to offset the loss of Flint Creek and Turk, Arkansas Electric's options are limited. One option would be to use a large number of low-capacity combustion turbines ("CTs") all running at a capacity factor of 20% or less. For example, to achieve even 200 MW of reliable baseload generation, Arkansas Electric would need to build 1000 MW worth of CTs. Another option could be to use intermediate load units, all running at a capacity factor of 40%. In this scenario, Arkansas Electric would need to build 500 MW worth of CTs to realize 200 MW of reliable baseload generation. Under either of these options, for this new generation to be available by 2032, Arkansas Electric must begin spending money now for planning, design, siting, permitting, and construction.

28. This new equipment is available only from a limited number of original equipment manufacturers, all of whom are facing an increase in demand from other affected utilities across the country. Given the long lead times for construction projects, Arkansas Electric must begin to design, permit, site, procure, and construct immediately merely to have a chance to have replacement power online by the end of 2031.

29. Arkansas Electric will also need to secure a reliable supply of natural gas for this new generation. But no natural gas operator is likely to take all those steps without a substantial, up-front commitment from Arkansas Electric—either in the form of a capital contribution to a pipeline project, or in the form of a long-term (20-30 year) supply contract, which may be thwarted by forthcoming regulations on natural gas units. Even if Arkansas Electric identified an operator and agreed to such terms, there is no guarantee that such a pipeline would actually be completed. Permitting, construction delays, right-of-way issues, and myriad other factors could block the pipeline or could delay it beyond the Final Rule's compliance deadlines.

30. Constructing new generation will also require Arkansas Electric to obtain new state and federal permits. But obtaining these permits is expensive and time consuming, and their issuance is also subject to judicial review. In order to have permitting in place by 2032, Arkansas Electric must immediately begin the permitting process for Flint Creek and Turk.

ABSENT A STAY, ARKANSAS ELECTRIC WILL SUFFER IMMEDIATE IRREPARABLE HARM

31. *Immediate replacement power costs.* Arkansas Electric would need to replace approximately 335 MW of baseload, dispatchable generation as a result of the Final Rule. This is in addition to the 1,168 MW of baseload generation Arkansas Electric will lose by 2030 when other co-owned plants are expected to close because of previously promulgated environmental regulations. The Final Rule has compounded and exacerbated the situation and Arkansas Electric is now faced with replacing approximately 1,500 MW of baseload generation to account for this loss, anticipated load growth, and increasing winter peaks. Replacing that approximately 1,500 MW of baseload generating capacity actually requires Arkansas Electric add over 2,200 MW of new generation as a result of the ever-increasing reserve requirements imposed by the two Regional Transmission Organizations ("RTOs") to which Arkansas Electric belongs, Southwest Power Pool ("SPP") and Midcontinent Independent System Operator ("MISO"). This additional generation need alone will result in over approximately $3 billion in new capital investments, which will be passed on to members and ratepayers

through a series of annual rate increases. Renewable energy sources (such as wind and solar) cannot satisfy that demand. Land acquisitions alone would be cost-prohibitive. But even ignoring that, renewables are an intermittent resource that are available only some of the time. Arkansas Electric cannot rely on renewables for all of its baseload generation—which must be available all of the time. Placing total dependence on renewables is a recipe for disaster if people need power to heat their homes at nighttime (no solar) or in calm conditions (no wind), let alone during extreme weather events. Thus, for replacement power, Arkansas Electric must immediately begin the process of procuring, permitting, and installing new natural gas combustion turbines to replace the capacity that will be lost due to the compounding retirements of the Flint Creek and Turk power plants.

32. *Immediate pipeline costs*. Those new turbines will require a reliable supply of natural gas to operate. To transport natural gas to Flint Creek and Turk, securing the right-of-way, surveying, and permitting can be expected to take several years (at minimum). Construction is likely to take at least another two years—and longer if there is litigation or challenges to the

permits. Given the recent history of opposition to natural gas pipelines, significant extra time must be built into this schedule to account for litigation and other opposition. Even when natural gas service is in close geographical proximity, the cost of connecting to a suitable service line can be prohibitively expensive and is unlikely to be available by 2032. Arkansas Electric must immediately begin making capital expenditures to attempt to bring these resources into existence by the 2032 deadline.

33. *Immediate impacts of stranded costs*. As discussed above, the retrofits or modifications to either Flint Creek and Turk required by the Rule are not economically or technologically feasible. The Rule will thus result in the premature retirement of these assets, leaving significant stranded asset costs, with Arkansas Electric members and rate-payers absorbing the impact. Assuming no further investment in new additions and excluding retirement costs, simply using the estimated book values to represent stranded costs as of year-end 2032 for Flint Creek and Turk yields estimates of approximately $154.7 million and $97.6 million respectively. This means that retiring Flint Creek and Turk by 2032 would require an additional $18.2 million and $11

million in annual accelerated depreciation respectively. These stranded costs would be in addition to the incremental capital investments required to replace the loss of baseload generating capacity as described above.

34. All of these near-term costs will immediately impact Arkansas Electric's members, and ultimately their rural consumers. And none of these costs are subject to refund. Equipment cannot be returned. Dollars spent on designing, permitting, engineering, and other studies cannot be refunded and returned to the members.

35. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of NRECA's Petition for Review. At best, Arkansas Electric expects that process to take at least 2-3 years. But the Final Rule's compliance deadlines do not give Arkansas Electric time to spare. Instead, haste is of the essence, for several reasons.

36. *Supply chain delays*. Original equipment manufacturers are already experiencing a surge in demand for new combustion turbines. Equipment lead times are currently over three years. Because of this rule, one can expect that original equipment manufacturers will soon be

inundated with new purchase orders from utilities all across the country. Equipment for natural gas co-firing is highly specialized and site-specific. Lead times for the equipment are already several years. Those lead times will only grow if the Final Rule takes effect. This creates a "race" among utilities that need to order new equipment, each one hoping to be nearer the front of the queue. Arkansas Electric is not immune to that dynamic. Thus, Arkansas Electric has no choice but to begin purchasing equipment before the courts can adjudicate NRECA's challenge to the Final Rule on the merits.

37. *Labor market delays*. Complying with the Final Rule will require Arkansas Electric to hire consultants, engineers, attorneys, and other professionals to manage the vast amounts of design, modeling, permitting, and other work required to secure replacement power. Yet these markets are also subject to the laws of supply and demand. As utilities across the country rush to hire the same professionals, prices will increase. Accordingly, utilities must move early—not only to insulate themselves from price pressures, but also in an attempt to ensure that the needed professionals are even available.

38. *Financing delays*. Arkansas Electric also must factor in financing delays. The Final Rule will require Arkansas Electric to make major capital investments in replacement power. The U.S. Department of Agriculture's ("USDA") Rural Utilities Service ("RUS") has historically helped coops obtain and secure financing, with the mission of electrifying and maintaining critical infrastructure in rural America. Obtaining RUS financing is a multi-step process. During project development and prior to construction, Arkansas Electric's project engineering team must prepare initial scoping and draft a project justification for the projected spending. This process involves reaching out to third-party vendors to confirm cost estimates, design, and operational specifications. RUS must approve the Work Plan.

39. Arkansas Electric has been proactive in its approach to leverage all federal funding opportunities, including applying for Empowering Rural America (New ERA) funding made available under the Inflation Reduction Act (IRA) and available only to rural electric cooperatives. In its application, Arkansas Electric requested funding for new renewable generation and transmission that would help replace the baseload it anticipates will be lost

as the result of these rules. The RUS has notified Arkansas Electric that the renewable projects we submitted were not approved for funding under the New ERA program.

40. *NEPA delays*. RUS financing also requires compliance with the National Environmental Policy Act ("NEPA"), which adds additional time at the beginning of a large project and is subject to judicial review. USDA regulations set forth the procedures that RUS follows when conducting environmental reviews. The environmental review requirements are established by NEPA, which requires all federal agency actions or approvals to go through a standardized environmental review process to evaluate what effect their proposed actions (*i.e.*, projects) would have on the environment. RUS may require development of Environmental Reports for certain Categorical Exclusions, Environmental Assessments, or Environmental Impact Statements depending on the complexity and scale of the project. The environmental review process and timelines depend upon the scope of the project and ultimately what project documents RUS will

request that the cooperative submit. However, a large project (such as a pipeline or a power plant) is likely to trigger NEPA.

41. Arkansas Electric must wait for the conclusion of RUS's environmental review before proceeding with major steps on projects that depend on RUS financial assistance. Once RUS releases funds, the project engineering, design, and competitive bidding process may commence. While other financing options may be available for certain types of projects, the interest rates are significantly higher. Arkansas Electric is a not-for-profit cooperative, and its members serve consumers in rural areas, many of which are economically disadvantaged. These communities are very sensitive to rate increases. Arkansas Electric regularly depends on RUS to help finance environmental compliance and other projects. This process alone can take years—and even longer if the NEPA review is challenged in the courts.

42. Arkansas Electric has recent experience with the delays that can occur in connection with securing replacement power for coal-fired units that have announced an imminent retirement. Arkansas Electric is a co-owner of the Independence Steam Electric Station in Newark, Arkansas

(“Independence”). Arkansas Electric is also a co-owner of the White Bluff Steam Electric Station in Redfield, Arkansas (“White Bluff”). In 2018, Entergy Arkansas, LLC (“Entergy”), co-owner and the operator of these plants, announced that White Bluff and Independence would cease to burn coal in 2028 and 2030, respectively. The planning process to secure replacement power for these units began in June 2023. Arkansas Electric is nearing final selection for equipment to replace White Bluff and several months away from signing procurement contracts for new equipment related to Independence. The new CTs Arkansas Electric will use to replace White Bluff have over a 3-year lead time today. As we begin working towards the replacement of Independence, manufacturers have advised us to expect both combustion turbine and generating step-up unit (GSU) transformer lead times to extend with no end in sight to potential delays. The timeline for securing replacement power for Flint Creek and Turk is expected to be similar—or longer—due to the demand surge the Final Rule will create.

43. In sum, if the Final Rule remains in effect while NRECA’s challenge to the Rule is pending, Arkansas Electric will have no choice but

to incur significant nonrefundable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 9th day of May, 2024, in Little Rock, AR.

Vernon "Buddy" Hasten

Appendix 10

DECLARATION OF CRAIG GROOMS

I, Craig Grooms, declare as follows:

1. My name is Craig Grooms. I am the Chief Operating Officer at Buckeye Power, Inc. ("Buckeye"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have almost three decades of experience in electricity generation, and I have been employed at Buckeye since 2004. I hold a Bachelor of Science degree in Electronic Engineering Technology from the University of Dayton, as well as a Master of Business Administration degree from Otterbein University. As Chief Operating Officer at Buckeye, I am responsible for the management and direction of Buckeye's engineering and operations functions, including power delivery, engineering, information technology and resources, and market operations.

3. Buckeye is a member of the National Rural Electric Cooperative Association ("NRECA") and is also a member of America's Power. This

declaration is submitted in support of the litigation challenging EPA's final rule 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*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

4. I am familiar with Buckeye's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect Buckeye as well as its suppliers, members, consumers, and employees.

5. Buckeye is an Ohio non-profit corporation operating according to a cooperative business model. Buckeye commenced commercial operations in 1959 and provides wholesale electric service to its 25 members, which includes all electric distribution cooperatives engaged in the sale of electricity within the state of Ohio. The retail service area of Buckeye's members covers a substantial part of the land area of the state of Ohio and

extends into portions of 77 of Ohio's 88 counties. Buckeye's members currently serve approximately 400,000 consumers, 91% of whom are classified as residential (farm and nonfarm).

6. Buckeye is fully committed to environmental stewardship. In recent years, Buckeye has spent **well over $1 billion** installing state-of-the-art, high-performing selective catalytic reduction and jet bubbling reactor flue gas desulfurization equipment, as well as converting from wet to dry fly ash handling, upgrading its wastewater treatment systems, and closing coal combustion residuals ponds, all in compliance with numerous recent new and modified EPA rules, for Buckeye's coal-fired units at Cardinal Generating Station in Brilliant, Ohio ("Cardinal").

7. In 2003, selective catalytic reduction (SCR) equipment was placed in commercial operation at Cardinal at a total capital cost of approximately $185 million. In 2008, construction of flue gas desulfurization (FGD) equipment was completed and placed into service on Unit No. 2 at Cardinal. The capital cost of the equipment was approximately $275 million. In 2012, FGD equipment was installed on Unit No. 3 at Cardinal, for a capital

cost of approximately $400 million. In 2021, dry fly ash handling equipment was installed at the Cardinal Plant at a capital cost of approximately $60 million.

8. In 2023, the bottom ash handling systems were modified to a closed loop configuration at a capital cost of approximately $30 million. Buckeye expects to close its fly ash and bottom ash ponds by 2025 at a cost of approximately $80 million. Buckeye is currently in the process of upgrading its flue gas desulfurization wastewater treatment plant to comply with the EPA's 2020 Effluent Limitation Guidelines ("ELG") by 2025 at a capital cost of approximately $30 million. Similar environmental capital investments have been made by the Ohio Valley Electric Corporation ("OVEC") for its two coal-fired power plants, of which Buckeye is an 18% owner and responsible for 18% of its costs.

9. Buckeye remains committed to maintaining a diverse portfolio of generation sources that balances affordability, reliability, and environmental responsibility. Buckeye's generation portfolio includes both fossil fuel-fired and renewable generating resources. In all, Buckeye's

portfolio of owned or controlled generation resources includes coal (≈1,600 Megawatts ("MW")), natural gas (≈700 MW), and renewable energy (≈75 MW).

10. Buckeye owns or receives power from numerous electric generating units ("affected EGUs") that fall within the Final Rule's ambit and thus must comply with the Final Rule's stringent new standards for coal-fired steam units. These affected EGUs have remaining useful lives that will be significantly shortened under the Final Rule—all at substantial cost to Buckeye, and ultimately, to the rural consumers who are in Buckeye's service area. The table below identifies the coal-fired EGUs that will be impacted if the Final Rule takes effect, as well as Buckeye's current strategy to comply with the Final Rule and the approximate costs to Buckeye of that compliance strategy.[1]

[1] Buckeye is also the owner of approximately 700 MW of peaking gas-fired generation resources. Given the current annual capacity factors of these resources at less than 20%, Buckeye does not expect additional compliance strategies to be necessary for these resources as a result of the Final Rule.

Affected EGUs	State	Compliance Strategy	≈Cost to Buckeye[2]
Cardinal Units 1-2	OH	Retire before 2032, to claim Applicability Exemption	$800 million to $1.3 billion
Cardinal Unit 3	OH	Retirement already scheduled for 2028.	NA
Clifty Creek Units 1-6	IN	Compliance strategy to be determined by OVEC[3]	$25-100 million if compliance strategy is retire before 2032
Kyger Creek Units 1-5	OH	Compliance strategy to be determined by OVEC	$25-100 million if compliance strategy is retire before 2032

OVERVIEW OF THE FINAL RULE

11. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam units, under Section 111(d). 89 Fed. Reg. at 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* at 39902. Both existing and new units

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[2] Assuming that all 1,600 MW of replacement power is purchased from the PJM market during the period 2032 to 2040 and based on the difference between (a) expected forward prices for energy, plus capacity clearing prices of $100/MW-day to $250/MW-day, in the PJM market, and (b) the expected costs to operate the Cardinal and OVEC EGUs during that same period.

[3] Clifty Creek and Kyger Creek Power Plants are owned by OVEC of which Buckeye owns an 18% interest. Buckeye is also entitled to 18% of the power output from the Clifty Creek and Kyger Creek coal-fired units.

must meet emissions limits equal to what EPA says 90% carbon-capture-and-sequestration can achieve. Existing units that cannot achieve this must shut down. New units that cannot achieve this must drastically reduce their output of electricity.

12. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *Id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

13. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2

must be transported (usually via pipeline) to a sequestration site that can permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

14. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent "—*i.e.*, transforming a coal unit into one that combusts both coal and natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

15. Third, units that make a federally enforceable commitment to permanently cease operating before January 1, 2032, have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

16. *New gas-fired combustion turbine units*. For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* at 39908.

17. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* at 39917. "Intermediate load" units (those that sell 20-40% of their potential electric output) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO_2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

IMPACT OF THE FINAL RULE ON BUCKEYE

18. Buckeye relies on affected coal-fired EGUs for most of its current generation needs from a capacity perspective (1,600 MW out of 2,400 MW total owned or controlled capacity) and nearly all of its generation needs from an energy perspective (annually greater than 80% of its energy supply). Accordingly, the Final Rule will have a substantial impact on every aspect of Buckeye's operations. These impacts will ultimately be felt by the consumers in Buckeye's service area—many of whom live in persistent poverty conditions, and all of whom depend on reliable generation to power their homes and keep them warm during frigid winters.

I. Impacts at Cardinal Station — "Imminent" Retirement

19. Cardinal Power Plant has two affected EGUs, Units 1 and 2, that generate up to 1,180 MW for use by Buckeye. It is situated on the Ohio River in Brilliant, Ohio, about 50 miles west of Pittsburgh and 15 miles north of Wheeling, West Virginia. Cardinal Unit 1 was placed in commercial service in 1967 and was purchased by Buckeye in 2022, but its output is dedicated to others until 2028, when its output will become available to Buckeye. Cardinal Unit 2 also came on-line in 1967 and is owned by Buckeye and

dedicated to its use. Each Unit has generating capacity of 590 MW. Cardinal Unit 3, also owned by Buckeye, began operation in 1977 and has generating capacity of 620 MW, but it is committed to retire in 2028 rather than install the equipment for Unit 3 that would otherwise be required to be in service by 2025 to comply with EPA's 2020 ELG rule. Buckeye's purchase of Unit 1 paved the way for Buckeye to retire Unit 3 by the end of 2028, at which time Buckeye will rely on Cardinal Units 1 and 2 for its needs.

20. Unit 1's remaining depreciable life is indefinite, as Buckeye depreciates Cardinal assets based on an annual composite depreciation rate of 4% as capital assets are placed in service. Depreciable life is an accounting metric for allocating costs, not a measure of how long a plant can reasonably be expected to remain useful. No specific retirement date has been set for the Cardinal Units, other than Unit 3, which will retire no later than December 31, 2028. Likewise, Unit 2 has a long horizon of remaining useful life without a set retirement date for depreciation or any other purpose. With nearly 300 employees, and scores of vendors and contractors supporting them, Cardinal is a major economic force in the region. Because of those and other

factors, Buckeye had planned to keep Unit 1 and Unit 2 operating indefinitely and as long as physically and economically viable. Yet, because of the Final Rule, Buckeye now plans to retire these units before 2032, and believes that it is likely that OVEC will make a similar determination with respect to its units, of which Buckeye has an 18% interest and 400 MW entitlement.

21. *CCS is not achievable at Cardinal*. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if they can achieve 90% CCS before 2032. CCS is not a technically or commercially viable solution for Cardinal, certainly not before 2032. This conclusion is based on Buckeye's understanding of current CCS technology from knowledgeable sources such as the Electric Power Research Institute (EPRI)[4]. This conclusion is also based on the problems involved in even considering CCS for Cardinal, including

[4] See EPRI Comments on EPA's proposed greenhouse gas rule for power plants, dated August, 2023, filed in Docket ID: EPA-HQ-OAR-2023-0072 (the "Proposed Rule"), at page 4. "The power industry's experience with full-scale construction, deployment, and operation of CCS technology is nascent. A phased approach to CCS deployment is needed to allow further demonstrations in order to answer key questions around costs, development, and operation prior to industry-level deployment."

lack of available storage sites for CO_2, costs and permitting timelines for CO_2 storage, pipelines to transport captured CO_2 from Cardinal to storage sites (even assuming such sites are available), the amount of Cardinal generation output that would be required to power CCS equipment at Cardinal (thereby reducing overall Cardinal plant efficiency and net output), and the strict requirement under the Final Rule to capture 90% of Cardinal's CO_2 emissions—a requirement that has not been demonstrated anywhere.

22. Buckeye understands that one of the only CCS projects currently proposed for a coal-fired power plant, *i.e.* Project Tundra at Young Station in North Dakota, would not meet the 90% carbon capture rate required by the Final Rule, and this is for a coal-fired power plant much smaller than Cardinal. Buckeye will continue to monitor the status of CCS technology, but right now the technology remains in a nascent and experimental state that is not technically or commercially viable for Cardinal. Furthermore, even if CCS were a technically and commercially viable compliance strategy for Cardinal, permitting, siting, design, and construction standards for CCS—including for CO_2 storage and CO_2 pipeline transportation from Cardinal to

storage, as well as the CO_2 capture technology itself—mean that any such CCS system could not be placed into service by the January 1, 2032, compliance date required by the Final Rule.

23. *Natural gas co-firing is not achievable at Cardinal*. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if they begin co-firing with 40% natural gas by January 1, 2030. Given the costs and time necessary to extend natural gas supplies to Cardinal, the inefficiencies of the older Cardinal cycle design as compared to modern, efficient gas combined cycle plants already in service or planned to be in service, and given the limited time that natural gas co-firing would be allowed under the Final Rule (only through 2038), the Medium Term compliance strategy is not a commercially viable option for Buckeye.

24. Buckeye has contacted two nearby interstate gas pipelines, one 6 miles distant and the other 33 miles distant, and has estimated the cost to extend gas supplies from such interstate pipelines to Cardinal as between $100-200 million dollars, as well as requiring a firm commitment from Buckeye to purchase gas transportation services for 20-25 years in order for

the pipeline company to amortize the cost of the new pipeline lateral through rates charged to Buckeye. Such a long-term commitment makes little sense given that Cardinal would be forced to retire Cardinal by the end of 2038 under the Final Rule, far short of the full 20-25 year purchase commitment that would be required from the pipeline company.

25. Furthermore, even if this option were commercially viable, it may not be practically possible by January 1, 2030, given the time needed to permit and install pipeline laterals to Cardinal from the nearby interstate gas pipelines, which Buckeye understands would take a minimum of 5 years to permit. Buckeye is also exploring whether unprocessed gas from local wells would be available from local intra-state gathering pipelines, rather than from interstate gas pipelines, but Buckeye has not confirmed that any such gas would be available in sufficient quantities or of a sufficient quality to support co-firing at Cardinal or what regulatory and permitting requirements would apply to such arrangements, as compared to purchases of processed gas from interstate pipeline.

26. *Imminent retirement is the only option for Cardinal.* Because the Final Rule's other purported compliance pathways are not demonstrated and are not commercially viable, Buckeye would have no choice but to retire Cardinal Units 1 and 2 before 2032 if the Final Rule remains in effect during this litigation. Under that compliance option, Buckeye would be permitted to continue to operate its Cardinal Units through the end of 2031 under current carbon emission rates, and without needing to install expensive or unavailable technologies or alter operations in a way that would not justify the limited amount of additional time that the units would be permitted to operate with such technologies or changed operations in place.

27. To meet the Final Rule's deadline for these retirements, Buckeye must immediately begin spending money across several expense categories.

28. *Replacement power costs.* Buckeye must replace approximately 1,180 MW of power (1,600 MW including OVEC) that will disappear by the end of 2031 as a result of the Final Rule's forced shut-down requirement for Cardinal Units 1 and 2. But Buckeye still must continue to provide power to its members. That will require either buying new power from the market

and/or building new generation. Based on current expected market prices for power during the period 2032 to 2040 (a period of just 8 years), as compared to the expected costs of continuing to produce power from the Cardinal Units during that same period, replacing the Cardinal Units with market power for just eight years will cost approximately **$800 million to $1.3 billion ($850 million to $1.5 billion including Buckeye's share of OVEC)**—all costs that would ultimately be borne by the consumers in Buckeye's area.

29. Yet these assumptions reflect only *current* market dynamics. They are very likely to change for the worse once EGUs across the region and the Nation are contemporaneously turning to the market for replacement power and are turning to equipment manufacturers for new equipment because of the impacts of the Final Rule on all affected EGUs, not just Buckeye's.

30. If the Final Rule takes effect, electric markets will be highly constrained, as generators across the country will see reductions in their portfolios. Coal-fired power plants currently produce about 20% of the

United States electric supply that will almost certainly be entirely eliminated by 2032 under the Final Rule due to its unrealistic and unavailable compliance options. Depending on the results of portfolio modelling and other studies that Buckeye will conduct now that the Final Rule has been issued, Buckeye may need to construct at least some new generation to replace the generation to be retired under the Final Rule.

31. Yet the Final Rule also imposes stringent requirements for new baseload EGUs—all of which must achieve 90% CCS by January 1, 2032. That level of CCS and the compliance timeline is not technically or economically viable for new coal or gas-fired baseload EGUs based on Buckeye's current understanding of CCS technology.

32. Nor can Buckeye depend solely on renewables and battery backups for baseload generation. To attempt to provide replacement generation for the vast baseload power that Buckeye will lose under the Final Rule, and given the problems with renewable generation associated with its intermittent and non-dispatchable (*i.e.*, non-controllable) nature, and the inability to construct new baseload (*i.e.*, high capacity factor) generation that

is gas or coal under the Final Rule without the installation of unproven and experimental CCS technology, the only technically viable option under the Final Rule to replace baseload, dispatchable coal-fired generation (apart from nuclear) is to use a large number of low-capacity factor simple-cycle combustion turbines (CTs) all running at a capacity factor of 20% or less[5], or a more expensive combined-cycle plant limited to a 40% capacity factor[6], and all depending on a fuel supply (gas) that is subject to high price volatility and limits on availability in the winter months, together with market purchases and/or renewables during the many hours that CTs would not be permitted to run given their low capacity factors. Low-capacity factor gas peaking generators combined with market purchases and/or renewables are in no way an adequate or equivalent replacement generation resource for

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[5] The expected capital cost of 1,600 MW of gas-fired simple-cycle CTs in PJM is $1.5 billion by itself at an estimated cost of $925/kW (as determined by PJM in a 2022 study), which does not include the additional cost of market purchases and/or renewables needed during the hours when the CTs can't run, nor does it include the cost of fuel, maintenance, repairs, etc. to run the CT's .

[6] The expected capital cost of 1,600 MW of gas-fired combined-cycle CTs in PJM is $1.9 billion by itself at an estimated cost of $1,195/kW (as determined by PJM in the same 2022 study).

high capacity factor, dispatchable, load-following, baseload generation resources like Cardinal. Furthermore, for replacement generation to be available before 2032, Buckeye must begin spending money now for planning, design, siting, permitting, financing, equipment and fuel procurement, and construction. While nuclear is an option, its high initial capital costs, history of cost overruns, and long lead times for construction don't make it a viable replacement generation option if required to be placed in service before 2032 as the Final Rule requires.

33. In addition, prior to building or acquiring replacement peaking resources, Buckeye must begin spending money now for portfolio modelling and other studies so that the appropriate balance between replacement generation, market purchases, financial and fuel hedging, and other arrangements can be developed. This type of portfolio modelling would be a precursor to any definitive steps to obtain replacement generation resources.

34. Given the likely retirement of all or near all coal-fired baseload EGUs before 2032 under the Final Rule, the inability of new coal and gas-

fired baseload resources to be constructed so as to meet a 90% CCS by January 1, 2032, and the time required to design, plan, permit, site, finance and construct even intermittent renewables and low capacity factor simple-cycle CTs under normal conditions, let alone under conditions where a large part of the current generation fleet all needs to be replaced at the same time with the same type of replacement resources from the same vendors and service providers, and where electric demand is increasing rapidly as a result of the electrification of the economy, including in the transportation sector through increasing use of electric vehicles, and because of the rapidly increasing requirements of data centers for electric service to support artificial intelligence and cryptocurrency mining, reliability constraints and higher prices for electricity seem likely if the Final Rule is allowed to go into effect. Nearly every knowledgeable industry participant with an interest in maintaining a reliable electric system including the North American Electric Reliability Corp, the PJM Interconnection, the Mid-Continent Independent System Operator, the Electric Power Research Institute, and NRECA itself, along with members of Congress from both political parties, have expressed similar concerns regarding the proposed and now Final Rule.[7]

35. *Stranded costs*. The depreciable lives of Cardinal Units 1 and 2 are currently indefinite, as capital assets at Cardinal are depreciated as they are incurred under an annual composite depreciation rate of 4%.

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[7] *See* EPRI Comments on the Proposed Rule ("The combined effects of the proposed rules would impact approximately 40% of total U.S. dispatchable power generation capacity. To maintain reliability through the clean energy transition, the power sector would need to address the resulting dispatchable generation impact with similarly flexible resources. Phased approaches that involve full-scale demonstrations prior to widespread deployment are critical to a reliable and affordable transition."); NRECA Comments on the Proposed Rule filed August 8, 2023 (stating that the early retirements caused by the Rule "will pose direct threats to electric grid reliability that EPA fails to appropriately assess and inaccurately models."); Joint Comments of Electric Reliability Council of Texas, Inc.; Midcontinent Independent System Operator, Inc.; PJM Interconnection, L.L.C.; and Southwest Power Pool, Inc. to the Proposed Rule filed August 8, 2023 ("Without firm proof of the commercial and operational viability of these technologies [CCS and hydrogen cofiring], proceeding with these requirements could place the reliability of the electric grid in jeopardy."); Comments dated August 1, 2023 filed by 39 U.S. Senators on the Proposed Rule; and Comments filed June 9, 2023 and December 20, 2023 by U.S. Senator Joe Manchin III on the Proposed Rule. While NERC did not file comments on the Proposed Rule, NERC's "2023 Long-Term Reliability Assessment," published December 2023, emphasized the negative impact the Proposed Rule may have on reliability.

36. As soon as Buckeye is required to make a binding commitment to retire these units, which, under the Final Rule, is 2026 (24 months after the Final Rule goes into effect), then, under accounting rules, these units will no longer be able to be listed as plant in service or to be depreciated on Buckeye's books. Instead, Buckeye will be required in 2026 to immediately expense the remaining book value of these units or to create a regulatory asset. If the remaining book value is immediately expensed, this will result in a massive rate increase to the Buckeye members in that single year. For example, the expected book value of Cardinal Unit 2 alone at 2026 is $380 million. If this amount were to be immediately expensed this would represent a rate increase of 44% in that year as compared to current financial forecast of rates for that year.

37. Even if a regulatory asset is created and amortized through the expected remaining operating life of the units through the end of 2031, this will still result in an increase in Buckeye's rates during that period as compared to what would occur without the Final Rule. Based on forecasted rates for the period through 2031, if the regulatory asset for just Cardinal

Unit 2 were amortized over the period 2026 to 2031, this would result in an expected rate increase of 6% for each year from 2026 through 2031.

38. If, instead, Buckeye chooses to create and amortize the regulatory asset in 2032 or beyond, this will result in stranded costs and increased rates to the Buckeye members. That is because, after the end of 2031, Buckeye will be amortizing and expensing a regulatory asset after the associated units are no longer in service or available to supply power to Buckeye and its members. But, at the same time Buckeye will be required to acquire replacement power after 2031, whether from the market or through construction or acquisition of new generation resources, to replace the retired assets, meaning that, after 2031, Buckeye and its members will be paying both for the cost of replacement power and the remaining unamortized costs of Cardinal Units 1 and 2.

39. Buckeye will also incur additional stranded costs in the form of new and replacement equipment costs at Cardinal Units 1 and 2 placed into service after 2026 that would ordinarily be capitalized under an annual 4% composite depreciation rate if no firm retirement commitment were made,

but would, as a result of the Final Rule, after 2026 be required to be immediately expensed or turned into a regulatory asset as a result of the Final Rule. As mentioned above, if these costs are immediately expensed, that will result in large rate increases to the Buckeye members in the year the costs are expensed, and if, instead, the regulatory asset is amortized through 2031, this will also result in rate increases to the Buckeye members for the years through 2031. If the regulatory asset is amortized past 2031, this will result in a stranded asset and double costs to the Buckeye members for the years after 2031, including both replacement power costs and the unamortized costs of replacements or additions to Cardinal Units 1 and 2.

40. Finally, the Final Rule could result in the retirement of Cardinal Units 1 and 2 long before 2032, even before any appeals of the Final Rule are completed. If any unexpected new or replacement capital asset is required to be placed in service prior to 2032, Buckeye may be forced to retire the Cardinal Units rather than to make the capital expenditure if the cost of the capital expenditure can no longer be justified based on the shorter remaining operating life of the Cardinal Units resulting from the Final Rule as

compared to expected cost of power from the market during the same period. It is unknown when a Cardinal Unit may be required to make a new or replacement capital expenditure as a result of a failure of equipment, accident, or even other EPA rules, such as the 2024 ELG Rule (discussed below). Such retirement decisions are almost always irreversible once made, and certainly not without massive amounts of time and money spent changing course.

41. EPA finalized the new 2024 ELG Rule at the same time as the power plant greenhouse gas emissions Final Rule, as part of a coordinated and inter-related suite of four new rules affecting power plant air emissions, water discharges, and solid waste disposal. Buckeye is currently in the process of spending approximately $30 million to install facilities by 2025 to comply with the EPA's 2020 ELG Rule. The 2024 ELG Rule requires that facilities be installed by 2029 that are completely new and different from those required for 2020 ELG Rule compliance, making the 2020 ELG investments wasted and stranded investments. The 2024 ELG Rule provides an option for affected EGUs to make an election by no later than the end of

2025 to commit, through the issuance of a Notice of Planned Participation (NOPP), to retire their EGUs by the end of 2034. Importantly, if such a commitment is made, the affected EGU will not have to comply with the new mandates in the 2024 ELG rule, so long as the EGU complies by 2025 with the requirements of the 2020 ELG Rule, which 2020 ELG Rule investments are already underway in the case of Cardinal.

42. Given the substantial new investments required to be made by the 2024 ELG Rule[8], which may not be placed into service until as late as 2029, and the substantial wasted and stranded investments in 2020 ELG Rule compliance created by the 2024 ELG Rule, then if the 2024 ELG Rule is not stayed (or if the greenhouse gas Final Rule is not stayed and otherwise fully adjudicated and overturned by the end of 2025), it is likely that Buckeye and many other affected EGUs otherwise planning to operate past 2034 will make the election, provided by the 2024 ELG Rule, to issue a NOPP and commit to retire the affected EGUs by the end of 2034 so as to allow such

[8] Buckeye estimates the cost of 2024 ELG Rule compliance at Cardinal at approximately $70-100 million.

EGUs to operate at least until the end of 2031 (and perhaps a year longer) as permitted under the greenhouse gas Final Rule, rather than the end of 2029, which would be the longest that affected EGUs would be permitted to operate under the 2024 ELG Rule without making the substantial new investments required by such rule.

43. On the other hand, if Buckeye or any other affected EGU makes the decision to comply with the 2024 ELG Rule while it and the greenhouse gas Final Rule are under appeal for the next several years, the EGU would need to start spending money immediately on the investments required to comply with the 2024 ELG Rule by its 2029 compliance date, and thereby risk having those investments become uneconomic and stranded investments if the greenhouse gas Final Rule is not overturned and its effective 2031 retirement date thereby maintained.

44. In sum, without having the greenhouse gas Final Rule stayed and fully adjudicated and overturned by the end of 2025 (or the 2024 ELG rule also stayed), Buckeye and many other affected EGUs otherwise planning to operate after 2034 will be faced with the prospect of making an

uneconomic environmental expenditure (uneconomic because of the shortened life of the Cardinal Units resulting from the Final Rule) to comply with the 2024 ELG Rule, or making a retirement commitment through the issuance of a NOPP by the end of 2025 (earlier than the retirement commitment required under the greenhouse gas Final Rule, which is in 2026), with no assurance that such NOPP retirement commitment would not remain binding, or that compliance with the 2024 ELG rule by 2029 would even be possible, if the Final Rule were ultimately overturned at the end of the litigation process.

45. In Buckeye's opinion, the combined effect of the Final Rule and the 2024 ELG Rule is designed to pressure affected EGUs to make binding commitments to retire, whether by 2025 under the 2024 ELG Rule, and/or by 2026 under the greenhouse gas Final Rule, by forcing the affected EGUs to face the prospect of having to make uneconomic or technically impossible investments required under the rules, should the rules ultimately be upheld, while at the same time offering relief from the rules (to the end of 2031 in the case of the greenhouse gas Final Rule, and to 2034 in the case of the 2024 ELG

Rule) but only if binding commitments to retire are made during the limited window of time while the rules are still under appeal and regulatory uncertainty prevails. For this reason, and given the combined effect of the two rules, issued at the same time by EPA and as part of a package of four power plant rules, it is imperative that both the 2024 ELG Rule and the greenhouse gas Final Rule be stayed.

46. *Increased Labor, Procurement, Financing, and Fuel Supply Costs*. As a result of the Final Rule, Buckeye will be required in 2026 (and as early as 2025 under the 2024 ELG Rule) to make a binding commitment to retire its Cardinal Units by no later than the end of 2031 (and by the end of 2034 under the 2024 ELG Rule). And all coal-fired units in the country will be required to make compliance decisions resulting from the Final Rule (and the companion 2024 ELG Rule), many of which are also likely to make the determination that retirement by the end of 2031 (and/or by the end of 2034 under the 2024 ELG Rule) is the only viable compliance option. When this binding commitment is made, and even before the Final Rule (and the associated 2024 ELG Rule) is likely to have made its way through the appeals

process, this commitment (and the issuance of the Final Rule and the 2024 ELG Rule) is likely to have negative and immediate effects on labor, procurement, financing, and fuel supply costs.

47. Shutting down Cardinal Units 1 and 2 will require Buckeye to eliminate more than 200 full-time jobs. In addition to causing significant disruptions to the community and to Buckeye's employees and their families, the mandatory nature of these reductions may also increase the cost of labor in the near term. Labor costs may be higher for positions that are due to be eliminated.

48. Furthermore, the Final Rule may cause certain equipment suppliers to exit the coal-fired power industry or to increase their costs, knowing that most or all coal-fired power generation, i.e. their customers, will, as a result of the Final Rule, be required to retire or to reduce their operations anywhere from 2030 to 2038, and by the end of 2031 at Cardinal and likely many other coal-fired units, such as OVEC's.

49. The same dynamic is likely to affect coal suppliers. Buckeye has already seen some coal suppliers fail to offer coal supply beyond 2027

because of concerns about the future of coal-fired generation and, accordingly, their ability to stay in business.

50. Rating agencies may lower Buckeye's credit ratings as a result of the Final Rule and the 2026 binding commitment to retire by the end of 2031, and lenders may increase their borrowing costs to Buckeye, coal suppliers, and other vendors and service providers dependent on coal-fired EGUs as customers.

II. Impacts at Clifty Creek and Kyger Creek

51. As mentioned above, Buckeye is a minority (18%) co-owner of two generation facilities that are operated by OVEC. The Clifty Creek facility has six affected coal-fired EGUs, and the Kyger Creek facility has five affected coal-fired EGUs. As a result of its minority ownership and contractual rights to power, Buckeye receives approximately 400 MW of electricity from these two facilities.

52. Decisions about compliance at these facilities are not solely Buckeye's to make, and instead must be made by OVEC's Board of Directors and its management. Decision-making about the compliance plans for Clifty

Creek and Kyger is still in process. Even so, and for many of the same reasons discussed herein with regard to the Cardinal Units, it is likely that OVEC will also make the decision to retire its units by the end of 2031 (and/or by the end of 2034) as a result of the Final Rule (and its companion 2024 ELG Rule), and regardless, each of the available compliance pathways under the Final Rule would require Buckeye to immediately begin incurring substantial expenses from OVEC as it responds to the Final Rule (and 2024 ELG Rule) and evaluates compliance alternatives and potential retirement commitments that must be made as soon as 2026 (and 2025 under the 2024 ELG Rule).

53. If these facilities find it possible to comply with and decide to comply with either the long-term or medium-term subcategory, OVEC would need to begin making immediate plans and expenditures to assure that either CCS would be in service before 2032 or natural gas co-firing would be available before 2030. That would create immediate expenses for Buckeye. Yet if these facilities select the retirement applicability exemption, then Buckeye would need to begin making immediate expenditures related

to securing 400 MW of replacement power, whether that be from the market or from new owned or controlled generation, as discussed above related to Cardinal. If purchased from the market, those replacement power costs would reach roughly **$50-200 million** (using the same assumptions as above about the costs of replacement power in the market during the period 2032 to 2040 as compared to the expected costs to operate OVEC's EGUs during that same period).

ABSENT A STAY, BUCKEYE WILL SUFFER IMMEDIATE IRREPARABLE HARM

54. *Immediate replacement power costs*. The Final Rule will require Buckeye to secure replacement power as a result of the forced retirements of the Cardinal Units. There are only two options for replacement power. The first option is to build new generation. If Buckeye decides that it must replace the retired generation with other owned or controlled generation, then Buckeye will incur immediate costs to begin the design, planning, site selection and acquisition, equipment procurement, construction, contracting, permitting, financing, fuel supply, and other processes associated with building or acquiring new generation, even gas peakers.

55. Given that many existing generators are likely to also be forced into retirement before 2032 in order to claim an applicability exemption, much new replacement generation will be required across the country, resulting in cost increases and delays for all new generation projects. Planning and execution will need to begin immediately for such replacement generation to be in service before 2032. The second option is to purchase power from the market. But power markets are highly volatile, which exposes Buckeye and its members to large price swings and counterparty risk. If other power generators turn to the market all at once, that volatility will only become more pronounced. Planning for and attempting to mitigate the effects of this volatility has its own costs, such as developing and implementing a hedging strategy and plan. Buckeye cannot solve this volatility by simply building or buying new generation resources. Low-load "peaking" units are the only viable option for replacement capacity under the Final Rule. But the Final Rule also caps the capacity factor of these units, limiting them to 20%. That means they must be left idle 80% of the time. Purchases of market power would still be required during that time.

Therefore, Buckeye would still be exposed to market volatility and associated hedging costs even if it were to pursue a strategy of building or buying new generation resources to meet the replacement power needs that the Final Rule creates. Accordingly, no matter what compliance path Buckeye chooses, the costs of replacement power will begin accruing immediately.

56. *Immediate planning costs*. As mentioned above, as a result of the Final Rule (and companion 2024 ELG Rule), Buckeye will immediately begin incurring costs to model its portfolio without the Cardinal Units (and likely without the OVEC Units as well) after 2031, and to evaluate how best to replace that power supply whether that be from the market or replacement generation, or some combination of both. If replacement generation, as opposed to market power is the chosen alternative, the type of replacement power would also need to be determined, although in order to meet a 2031 in-service date, gas peakers seem to be the only viable option. This planning will also require Buckeye to spend money on portfolio and supply planning,

including associated hedging strategies, and to divert significant internal resources to analyzing the Final Rule's effects.

57. *Immediate Stranded Costs*. The Final Rule requires Buckeye to make a legally binding commitment for any retirements by 2026 (and by 2025 under the 2024 ELG Rule), when state implementation plans are due. As a result of such binding commitment, and as mentioned above, under accounting rules, Cardinal Units 1 and 2 will immediately become abandoned units, and Buckeye will no longer be able to list such assets as plant in service or depreciate these assets on its books. Buckeye will be required to immediately, in 2026 (or 2025 if the NOPP is made under the 2024 ELG Rule), expense any remaining book value for these units or to create and amortize a regulatory asset that will also result in increased rates if amortized over the period through 2031. The same dynamic will occur with any new or replacement capital assets at Cardinal placed in service starting in 2026 after the Cardinal Units become abandoned but prior to their actual retirement at the end of 2031 (or earlier). As mentioned above, the Final Rule could even result in a decision to retire the Cardinal Units prior

to 2031, and even while the Final Rule is still under appeal, if a major capital investment is required to be made (*e.g.*, an expensive repair or replacement), whether as a result of equipment failure or even other EPA rules, that could not be economically justified given the shorter remaining life of the plant resulting from the Final Rule.

58. If the 2024 ELG Rule is not stayed (or if the greenhouse gas Final Rule is not stayed and fully adjudicated and overturned by the end of 2025), and if Buckeye decides to make the additional investments required by the 2024 ELG Rule, rather than to commit in 2025 to retire the Cardinal Units by 2034 and avoid 2024 ELG compliance costs as permitted under the 2024 ELG Rule, these investments will become stranded investments should the Final Rule ultimately be upheld, as these investments will need to begin to made immediately in order to meet the 2029 compliance date required under the 2024 ELG Rule. If the Final Rule is upheld and the 2024 ELG Rule compliance investments are not completed at that time, Buckeye would likely cease any further investments in 2024 ELG Rule compliance and choose to retire in 2029, rather than continue to make further investments in 2024 ELG Rule

compliance, which only allow for operations for two years after 2029 until the 2031 retirement date for Cardinal resulting from the Final Rule. All of Buckeye's investments in 2024 ELG Rule compliance would then become stranded assets. In such a case, Buckeye's investments in 2020 ELG Rule compliance will also become stranded investments, as they will only be in service for the four-year period between the 2025 date for 2020 ELG Rule compliance and the 2029 date for 2024 ELG Rule compliance. If, instead, Buckeye would choose to complete 2024 ELG Rule compliance investments, these and the investments already made in 2020 ELG Rule compliance would still become stranded investments, as they will only be in service for six years, in the case of 2020 ELG Rule compliance investments (for the period between 2025 and 2031), and for two years, in the case of 2024 ELG Rule compliance (for the period between 2029 and 2031).

59. On the other hand, if Buckeye chooses by the end of 2025 to issue the NOPP under the 2024 ELG Rule and commit to retire Cardinal by 2034 (as a result of uncertainty about the greenhouse gas Final Rule's ultimate fate before the courts), then even if the Final Rule is ultimately overturned, such

relief will be illusory (if the 2024 ELG Rule is not also overturned), as Buckeye will have made a commitment in 2025 to retire Cardinal by 2034, even if Buckeye would have otherwise been willing to make the investments in 2024 ELG Rule compliance allowing Buckeye to operate indefinitely past 2029 had Buckeye known, at the time it was otherwise required to make the 2024 ELG Rule NOPP election in 2025, that the power plant greenhouse gas Final Rule would ultimately be ruled invalid.

60. *Immediate Labor, Procurement, Financing and Fuel Supply Costs.* As mentioned above, the Final Rule is likely to result in immediate increases in labor, procurement, financing and fuel supply costs, and could result in some suppliers leaving the industry entirely, as under the Final Rule, all coal-fired power plants will be required to retire by no later than 2038 and most by 2031, given that CCS and all compliance options other than retirement are technically and commercially not achievable before 2030, if at all. This same dynamic is caused by the binding retirement decisions that must be made no later than the middle of 2026 (if not sooner, given that States will call for State-plan information long before the plans are due), both

for the Cardinal Units, OVEC, and other coal-fired power plants across the country, as well as the retirement decisions that must be made by 2025 under the 2024 ELG Rule.

61. *Immediate costs to Buckeye's members and consumers.* All of these near-term costs will begin flowing to Buckeye's members—and ultimately to the rural consumers who depend on Buckeye to keep their lights on when it is dark and to keep their heaters on when it is cold.

62. These costs are not reversible. Equipment generally cannot be returned without cost. Dollars spent on portfolio modeling, generating facility design, planning, permitting, engineering, site selection and acquisition, fuel procurement, financing and other studies and costs cannot be refunded. Legally binding retirement promises generally cannot be undone. Buckeye might even be forced into a retirement decision earlier than 2031, perhaps while the Final Rule is still on appeal, if a major capital expenditure at the Cardinal is required to be made as a result of equipment failure, or other EPA rules, such as the 2024 ELG Rule, that could not be

justified given the before-2032 retirement date that is Buckeye's only viable option under the Rule.

63. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of this litigation. Optimistically, Buckeye expects that process to take *at least* 2-3 years. But the Rule's compliance deadlines do not give Buckeye any time to spare. On the contrary, time is of the essence, unless the Final Rule is stayed.

64. In sum, if the Final Rule remains in effect while this litigation is pending, Buckeye will have no choice but to incur significant unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 9th day of May, 2024, in Columbus, OH.

Craig Grooms

Appendix 11

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION,	)	
Petitioner,	)	
v.	)	Case No. 24-1122
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,	)	
Respondents.	)	

DECLARATION OF BEN PORATH

I, Ben Porath, declare as follows:

1. My name is Ben Porath. I am the Executive Vice President and Chief Operating Officer at Dairyland Power Cooperative ("Dairyland"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

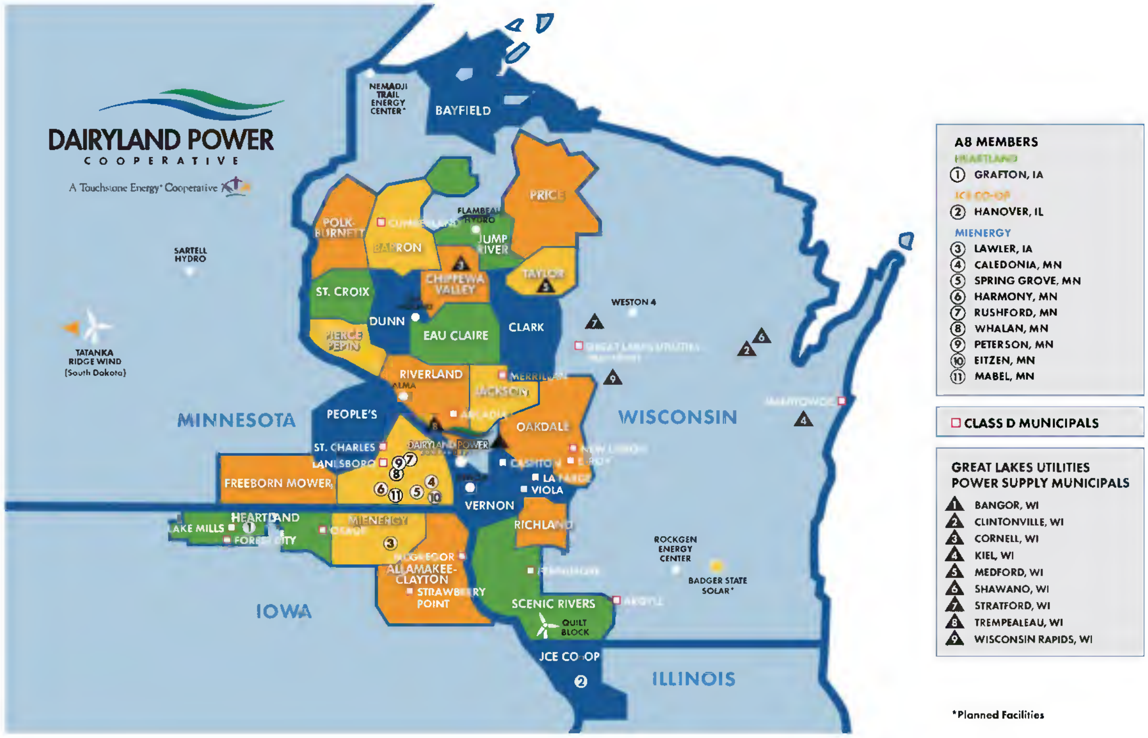
2. I have over 25 years of experience in electric reliability, wholesale electric markets, and electricity generation. I have been employed at

Dairyland since 2003. I hold a bachelor's degree in Physics from Hamline University in St. Paul, Minnesota, as well as Juris Doctorate degree from William Mitchell College of Law, also in St. Paul, Minnesota. As Executive Vice President and Chief Operating Officer at Dairyland, I am responsible for all areas of Operations including Generation, Transmission, System Operations, Resource Planning, Engineering, and numerous other functions.

3. Dairyland is a member of the National Rural Electric Cooperative Association ("NRECA"). This declaration is submitted in support of NRECA's Petition for Review and Motion for Stay of EPA's final rule 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*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule"). I am familiar with Dairyland's operations, including generation and transmission, regulatory compliance, workforce management, and electric

markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect Dairyland.

4. Dairyland is a not-for-profit electric generation and transmission cooperative founded in 1941 and headquartered in La Crosse, Wisconsin. Its purpose is to supply safe, reliable, and cost-effective wholesale electric power to its members—24 not-for-profit distribution cooperatives and 27 municipal utilities—while abiding by all applicable regulatory requirements. Dairyland's members provide power to meet the energy needs of approximately 700,000 retail-consumers in a four-state service area spanning parts of Wisconsin, Minnesota, Iowa, and Illinois. The figure below shows the location of Dairyland's electric generating units and its members' service territories.



5. Dairyland currently projects that overall energy sales in the Dairyland service area will grow at an annual average rate of 0.7% from 2023 to 2039, and that peak demand will grow at an average annual rate of 0.6%. However, this "base case" forecast does not account for robust growth in electric vehicles sales, or for developing commercial and industrial trends such as data center construction. Adding those factors to Dairyland's projections shows a scenario in which overall demand grows at an average annual rate of 2.8%, while peak demand grows at 2.4% from 2023 to 2039.

6. Dairyland is committed to sustainably and reliably transitioning to a lower-carbon future. To that end, Dairyland is diversifying its generating resources, which currently include wind, solar, renewable-enabling natural gas, coal, hydro, and biogas. Dairyland plans to open additional facilities that will further diversify its portfolio of generating resources. Dairyland's 149 megawatt ("MW") Badger State Solar project, slated to begin operation in 2025, is expected to generate enough solar energy to power more than 20,000 homes. Dairyland also holds a 50% stake in the Nemadji Trail Energy Center project, which is scheduled to become operational in 2028. This project is a combined-cycle natural gas power plant meant to enable solar and wind growth while maintaining system reliability.

7. Dairyland has seen how regulatory and legal hurdles can delay clean energy deployment and raise energy prices for consumers. In part due to its experience with regulatory review and litigation postponing the launch date of the Nemadji Trail Energy Center, Dairyland has taken an active role in advocating for permitting process modernization, including in testimony to the U.S. Congress. Because of the challenges associated with opening new

clean energy facilities, traditional fossil fuel generating resources play an important role in ensuring reliable energy generation for the cooperatives and municipalities that depend on Dairyland for their power.

8. Dairyland owns and operates a coal-fired electricity-generating unit, the John P. Madgett station ("Madgett Station") located in Alma, Wisconsin. Madgett Station consists of a single unit with a net output of 387 MW, and it has been in operation since 1979. Dairyland has invested significant resources to ensure Madgett Station's long-term operability, and Madgett Station is expected to remain operational until at least 2042.

9. Dairyland also owns, but does not operate, a 30% share of the Weston 4 coal-fired electricity generating station located in Rothschild, Wisconsin. Weston 4 has a net output of 595 MW and has been in operation since 2008. Weston is a multi-unit power plant site, majority owned and operated by WEC Energy Group headquartered in Milwaukee, Wisconsin.

OVERVIEW OF THE FINAL RULE

10. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam units, under Section 111(d). 89 Fed. Reg. at 39840.

The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* at 39902. Both existing and new units must meet emissions limits equal to what EPA says 90% carbon-capture-and-sequestration can achieve. Existing units that cannot achieve this must shut down. New units that cannot achieve this must drastically reduce their output of electricity.

11. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *Id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841. To make an effective election for subcategorization, affected units must inform state regulators of their choice before the state submits its State plan to EPA. If Wisconsin fails to submit a plan or, if EPA determines that Wisconsin's plan is not satisfactory, EPA has

authority to establish a plan itself. If an affected electricity generating unit does not make an effective election for subcategorization, it is required to comply with the default, long-term "best system of emission reduction" of achieving 90% CCS by January 1, 2032.

12. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

13. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-

firing with natural gas[] at a level of 40 percent"—*i.e.*, transforming a coal unit into one that combusts both coal and natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

14. Third, units that make a federally enforceable commitment to permanently cease operating before January 1, 2032, have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

15. *New gas-fired combustion turbine units.* For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* at 39908.

16. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* at 39917. "Intermediate load" units (those that sell 20-40% of their potential electric output) must comply with a

standard based on "high-efficiency simple cycle turbine technology." *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO_2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

IMPACTS OF THE FINAL RULE ON DAIRYLAND

17. *CCS is not achievable at Madgett Station.* The Final Rule allows existing coal-fired units to remain in operation beyond 2038 only if they can achieve 90% CCS by 2032. That is not possible at Madgett Station. The technology to reliably achieve 90% CCS is not available. And even the emerging technology that is available is unreliable and prohibitively expensive. But technological issues are not the only thing preventing Madgett Station from relying on the 90% CCS compliance path.

18. Even if 90% of the CO_2 could be captured, it would need to be transported for storage. The two nearest CO_2 sequestration sites are in Otsego County in northern Michigan and in Decatur, Illinois, located 370 and 345 miles away from Madgett Station, respectively. Even if these sites prove to be capable of safely storing CO_2 at the quantities necessary to accommodate Madgett Station's captured CO_2, no pipeline exists to carry captured CO_2 from Madgett Station to either of the storage facilities. Any such pipeline would need to go under either Green Bay and Lake Michigan (for the Michigan storage facility) or numerous smaller lakes, rivers, and nature preserves (for the Illinois storage facility). Setting aside the prohibitive costs these projects would entail, the permitting, siting, design, and construction would take much longer than the few years that the Final Rule allows, and the pipelines would not be operational before 2032. Accordingly, this compliance pathway is not an option for Madgett Station.

19. *Natural gas co-firing is not achievable at Madgett Station*. The Final Rule allows affected electricity generating units to remain in operation through the end of 2037 only if they begin co-firing with 40% natural gas by

January 1, 2030. There are currently no natural gas transmission pipelines near Alma, Wisconsin, nor could such a pipeline be permitted and constructed in time for compliance with the Final Rule's deadlines.

20. Even if such a project were technically possible, it would be cost-prohibitive. In 2012, Dairyland commissioned a study to determine the cost of bringing natural gas to Madgett Station. The study determined the construction costs alone would be approximately $100 to $200 million in 2012 dollars, not including any costs associated with environmental permitting or use of private land. Nor did the study account for the costs of retrofitting Madgett Station to co-fire natural gas. Factoring in all these costs, co-firing natural gas at Madgett Station would be prohibitively expensive, especially since Madgett Station would be required to shut down soon after undertaking this massive pipeline construction project and installing new equipment. Therefore, the "medium-term" compliance pathway is not available at Madgett Station.

21. *Imminent retirement is the only option for Madgett Station*. Because the Final Rule's other purported compliance pathways are not

demonstrated, available, or achievable, Dairyland has no choice but to retire Madgett Station by 2032—ten years before the end of its useful life.

ABSENT A STAY, DAIRYLAND WILL SUFFER IMMEDIATE IRREPARABLE HARM

22. *Immediate replacement power costs.* Dairyland would need to **replace approximately 387 MW of baseload**, dispatchable generation as a result of the Final Rule. Renewable energy sources (such as wind and solar) cannot satisfy that demand. Renewables are an intermittent resource that Dairyland cannot rely on for constant baseload generation. Placing such a high level of dependence on renewables is a recipe for disaster. For example, people still need power to heat their homes at nighttime (no solar) and in multi-day calm conditions (no wind), and existing battery-storage technology cannot bridge that gap.

23. Thus, for replacement power, Dairyland must turn to natural gas (or to prohibitively expensive traditional nuclear power). Yet today's state-of-the-art natural gas combined cycle units ("Combined Cycles") cannot achieve the 90% CCS that the Final Rule demands. Even if those units could achieve 90% CCS, there are no viable long term storage locations in the

vicinity of the facilities. No matter what source Dairyland turns to for replacement power, it will need to imminently begin incurring expenses.

24. Equipment and labor lead times are already drawn out and will only grow longer as a result of the Final Rule. Before any new construction can even begin, design, permitting, and siting must happen, which takes *at least* 3-5 years to complete—even when everything goes according to plan. A number of factors play into this timeline, including natural gas availability and the potential need to permit and construct new gas pipeline infrastructure (if Dairyland chooses to use natural gas for new generation).

25. *Immediate costs to Dairyland's members and consumers.* All of these near-term costs will begin flowing to Dairyland's members—and ultimately to the rural consumers who depend on Dairyland to keep their lights on when it is dark and to keep their heaters on when it is cold.

26. These costs are not recoverable. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded. Legally binding retirement promises cannot be undone.

27. Furthermore, these costs cannot be deferred or delayed until the courts reach a final ruling on the merits of NRECA's Petition for Review. Optimistically, and given that it took 7 years to litigate the Clean Power Plan, Dairyland expects this litigation to take *at least* 5 years. But the Final Rule's compliance deadlines do not give Dairyland that much time to spare. For one thing, the Final Rule's one-year compliance extension mechanism is available only if Dairyland "has made all reasonable efforts to achieve timely compliance" and "has acted consistent with achieving timely compliance." 89 Fed. Reg. 607. In other words, Dairyland must act *now* in order to preserve its ability to claim the Final Rule's one-year compliance extension mechanism (assuming that this extension is even included in the implementation plan that will govern Dairyland—whether state or federal). For many other reasons, too, haste is of the essence.

28. *Supply chain delays*. Original equipment manufacturers will soon be inundated with new purchase orders from electric utilities all across the country. For example, lead times for new Combustion Turbines are *already* several years long. Those wait times will only grow if the Final Rule takes

effect. This creates a "race" among electric utilities that need to order new equipment, each one hoping to be nearer the front of the queue. Dairyland is not immune to that dynamic. Thus, Dairyland has no choice but to begin purchasing equipment before the courts can adjudicate NRECA's challenge to the Final Rule on the merits.

29. *Labor market delays*. Complying with the Final Rule will require Dairyland to hire swarms of consultants, engineers, attorneys, and other professionals to manage the vast amounts of design, modeling, permitting, and other work required under the Final Rule—not only to achieve replacement power, but also to comply with all the requirements that apply to shutting down a plant such as Madgett Station. Yet these markets are also subject to the laws of supply and demand. As electric utilities across the Nation rush to hire the same professionals, prices will increase. Accordingly, electric utilities (including cooperatives) must move early—not only to insulate themselves from price pressures, but also in an attempt to ensure that the needed professionals are even available.

30. *Financing delays*. On top of the delays that EPA has already discussed in the Final Rule, Dairyland must factor in financing delays. The Final Rule will require Dairyland to make major capital investments in replacement power. The U.S. Department of Agriculture ("USDA") Rural Utilities Service ("RUS") has historically helped cooperatives obtain and secure financing, with the mission of electrifying and maintaining critical infrastructure in rural America. Obtaining RUS financing is a multi-step process. During project development and prior to construction, the cooperative's project engineering team must prepare initial scoping and draft a project justification for the projected dollars to be spent. This process involves reaching out to third-party vendors to confirm cost estimates, design, and operational specifications. RUS must approve the Work Plan.

31. *NEPA delays*. RUS financing also requires compliance with the National Environmental Policy Act ("NEPA") and the National Historic Preservation Act, which adds additional time at the beginning of a large project and is subject to judicial review. USDA regulations set forth the procedures that RUS follows when conducting environmental reviews. The

environmental review requirements are set forth by NEPA, which requires all federal agency actions or approvals go through a standardized environmental review process to evaluate what effect their proposed actions (*i.e.*, projects) would have on the environment. RUS may require development of Environmental Reports for certain Categorical Exclusions, Environmental Assessments, or Environmental Impact Statements depending on the complexity and scale of the project.

32. As just one example, RUS NEPA review and approval of the Nemadji Trail Project took over six years to complete. While there have been other permitting challenges that have impacted various aspects of the Project, the lengthy NEPA process imposed delay in the issuance of the Army Corps of Engineers Section 404 wetland permit, added uncertainty and delay to the execution of procurement contracts, and caused compression of the Project's construction schedule.

33. The White House Council on Environmental Quality recently issued a new NEPA "Phase 2 Rule," which makes extensive regulatory changes and layers on numerous new requirements that will inject

additional uncertainty and delays into the NEPA process. Still, even without the latest regulations, the environmental review process and timelines depend upon the scope of the project and ultimately upon what project documents RUS will request that the cooperative submit. It is impossible to know in advance exactly what these requests will be, which again incentivizes Dairyland to act quickly.

34. Borrowers must wait for the conclusion of RUS's environmental review before taking major actions on projects or obtaining RUS financial assistance. While other financing options may be available for certain types of projects, the interest rates are significantly higher. Dairyland is a not-for-profit cooperative, and its consumers are in rural communities, many of which are disadvantaged. Both are very sensitive to rate increases. Dairyland regularly depends on RUS to help finance environmental compliance and other projects. This process *alone* can take at least two years—and even longer if the NEPA review is subject to a litigation challenge.

35. In sum, if the Final Rule remains in effect while NRECA's challenge to the Final Rule is pending, Dairyland will have no choice but to

incur large, unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 9th day of May, 2024, in La Crosse, WI

Ben Porath

Ben Porath

Appendix 12

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION,	)	
Petitioner,	)	
v.	)	Case No. 24-1122
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,	)	
Respondents.	)	

DECLARATION OF JUSTIN SODERBERG

I, Justin Soderberg, declare as follows:

1. My name is Justin Soderberg. I am the Vice President of Generation at Western Farmers Electric Cooperative ("Western Farmers"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have more than 20 years of experience in the utility industry, and I have been employed at Western Farmers since 2008. Prior to my current

position, I held the positions of Plant Engineer, Generation Engineering Manager, Plant Manager, and Senior Manager—all at Western Farmers. I hold a Bachelor of Science degree in mechanical engineering from the University of Memphis and a Master of Business degree from Union University. As Vice President of Generation, I am responsible for overseeing all aspects of electricity generation operations, including managing facilities such as power plants, renewable energy installations (like solar farms), and the other sources of electricity production owned or contracted by Western Farmers. I am also responsible for assessing future energy needs, evaluating potential new generation projects, and reviewing regulatory requirements.

3. Western Farmers is a member of the National Rural Electric Cooperative Association ("NRECA"). This declaration is submitted in support of NRECA's Petition for Review and Motion for Stay of EPA's final rule 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, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule"). I am familiar with Western Farmers' operations, including generation and transmission, regulatory compliance, workforce management, and electric markets. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect Western Farmers.

4. Western Farmers is a generation and transmission cooperative that provides electric service to 21 member cooperatives and Altus Air Force Base. These members are located primarily in Oklahoma and New Mexico, with some service areas extending into parts of Texas and Kansas. Western Farmers was organized in 1941 and has now been operating for more than 80 years. Western Farmers exists to deliver safe, reliable, and competitively priced wholesale energy across its large service territory—which includes more than two-thirds of the geographical region of Oklahoma, part of New Mexico, as well as portions of Texas and Kansas. The members in this service area serve a population of approximately 721,000 people. The following infographic illustrates Western Farmers' membership and service area:

5. Western Farmers owns and operates a diverse power generation fleet consisting of six steam and gas turbine power generation sites, five utility-scale solar farms, and 13 community solar farms. Western Farmers also has power purchase agreements for wind, solar, natural gas, and hydroelectric generation. The total combined capacity for owned and contracted assets is almost 2,400 megawatts ("MW"), all in Oklahoma and New Mexico. The following infographic summarizes Western Farmers' generation portfolio:

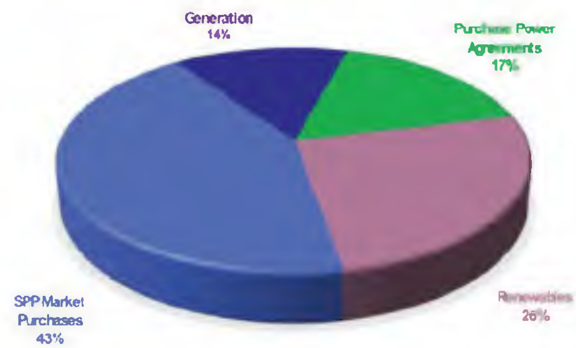
WFEC's Fuel Diversity - 2023

Renewables* - 26%
Wind - 20%
Solar - 1%
Hydro - 5%

Generation - 14%
Coal - 5%
Natural Gas - 9%

Power Purchase Agreements - 17%
Grand River Dam Authority
Oneta Power Plant
Southwestern Power Service

SPP Market Purchases - 43%**
(**Includes blend of resources.)



WFEC owns and operates a diverse power generation fleet consisting of gas and coal generation, in addition to solar and wind facilities. WFEC also has power purchase agreements for wind, solar, natural gas and hydroelectric generation.

The percentages listed represent an average of WFEC's kilowatt-hour (kWh) input into the SPP Market for 2023. All kWhs are then purchased from the market at SPP's blend of power.

**WFEC purchases or produces energy from various wind & solar resources. However, WFEC has not historically, nor may not in the future, retain or retire all of the renewable energy certificates associated with the energy production from these facilities.*

OVERVIEW OF THE FINAL RULE

6. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam units, under Section 111(d). 89 Fed. Reg. at 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* at 39902. Both existing and new units must meet emissions limits roughly equal to what EPA says 90% carbon-capture-and-sequestration can achieve. Existing units that cannot achieve

this must shut down. New units that cannot achieve this must drastically reduce their output of electricity.

7. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *Id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

8. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can permanently store it (usually underground). *See id.* EPA "assumes" that

"work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

9. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent"—*i.e.*, transforming a coal unit into one that combusts both coal and natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

10. Third, units that make a federally enforceable commitment to permanently cease operating before January 1, 2032, have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

11. *New gas-fired combustion turbine units.* For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These

subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* at 39908. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* at 39917. "Intermediate load" units (those that sell 20-40% of their potential electric output) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO 2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

IMPACT OF THE FINAL RULE ON WESTERN FARMERS

12. Western Farmers depends on coal-fired power to deliver reliable dispatchable generation, serve as an economic hedge to the volatile natural gas market, and ensure capacity in peak seasons and when other fuels like

natural gas or renewables such as wind, solar, and hydro are unavailable. The Final Rule will therefore have significant impacts on Western Farmers' operations. These impacts will ultimately be felt by the consumers in Western Farmers' service area—many of whom live in persistent poverty conditions, and all of whom depend on reliable generation to keep the lights on and to heat and cool their homes.

13. Western Farmers owns and draws power from the Hugo Power Plant ("Hugo"), which is a 427 nominal MW coal-fired electric generating unit located in Fort Towson, Oklahoma. Hugo is a regulated unit under the Final Rule, and therefore it must comply with the Final Rule's stringent new standards for coal-fired steam units. For Hugo, these standards amount to a forced retirement by the end of 2031. Yet Hugo's remaining useful life is much longer than that. The forced retirement of Hugo under the Final Rule will result in excess of $800 million in costs for Western Farmers, and ultimately, for the rural member consumers that Western Farmers serves.

14. *CCS is not achievable at Hugo.* The Final Rule allows Hugo to remain in operation beyond 2038 *only if* it can achieve 90% CCS by 2032. That

is not possible at Hugo. The technology to reliably achieve 90% CCS is not available. And even the nascent technology that is available is unreliable and is prohibitively expensive (and cannot achieve 90% capture in any event). But technological issues are not the only thing preventing Hugo from relying on the 90% CCS compliance pathway. Even if 90% of CO_2 could be captured from Hugo, it would need to be transported for storage. Transportation requires a pipeline, but no CO_2 pipeline exists near Hugo. Nor is it realistic to expect such a pipeline to come into existence before 2032. Permitting, siting, design, and construction will all take much longer than the few years that the Final Rule allows. Furthermore, even once CO_2 is transported, it must be stored. But research and implementation of a Class VI injection well program in Oklahoma is still in its early stages. Because of all that, the "long-term" compliance pathway is not an option for Hugo.

15. *Natural gas co-firing is not achievable at Hugo.* The Final Rule allows Hugo to remain in operation beyond 2032 only if it begins co-firing with 40% natural gas by 2030. This compliance pathway is not viable for Hugo, as there is currently no natural gas pipeline at or near Hugo, and it is doubtful a

pipeline for such supply could be permitted and constructed in time for the Final Rule's deadlines. Even if a supply of natural gas were available, the costs for retrofitting Hugo to co-fire with natural gas are prohibitively expensive (~$490 million)—especially since Hugo would then be required to shut down soon after making a huge investment in this new equipment and infrastructure. Therefore, the "medium-term" compliance pathway is not currently available to Hugo.

16. *Retirement is the only option for Hugo*. Because the Final Rule's other purported compliance pathways are not demonstrated, available, or achievable, the Final Rule leaves Western Farmers with no choice but to retire Hugo. To meet the 2032 deadline for this retirement, Western Farmers must immediately begin spending money across several expense categories.

17. *Replacement power costs*. Western Farmers must replace approximately 450 MW of power that will disappear by 2032 as a result of the Final Rule's forced shut-down requirement for Hugo. Throughout this process, Western Farmers must continue to provide affordable and reliable electricity to its members. Delivering on that obligation will require either

buying new power from the market or building at least 400 MW of new generation. Conservatively, replacing the power from Hugo will cost approximately **$800 million**—all costs that would ultimately be borne by the consumers in Western Farmers' area.

18. If the Final Rule takes effect, electric markets will be highly constrained, as generators across the country retire their assets. Depending wholly on the market for new reliable dispatchable power is thus a recipe for disaster. Accordingly, Western Farmers anticipates needing to construct at least some new generation as a result of the Final Rule. Yet the Final Rule also imposes stringent requirements for new reliable dispatchable gas-fired combustion units—all of which must achieve emissions limits that are based on 90% CCS. That level of CCS is not possible for these units. Nor can Western Farmers depend solely on renewables for reliable and dispatchable generation (as discussed below).

19. To ensure reliable replacement generation for the vast reliable dispatchable power that Western Farmers will lose under the Final Rule, the only viable option is to use a large number of low-capacity, simple-cycle

combustion turbines all running at a capacity factor of 20% or less, and all depending on a fuel supply (gas) that is subject to high price volatility and a fuel supply that must be delivered in real time. For example, to achieve just 200 MW of reliable dispatchable generation, Western Farmers may need to build *at least* 1,000 MW worth of combustion turbines—and maybe even more than that in order to meet the "reserve margin" requirements that are in place to protect reliability. For that generation to be available beginning in 2032 (to offset Hugo's retirement), Western Farmers must begin spending money now for planning, design, siting, permitting, equipment procurement, and construction.

20. *Workforce costs*. Shutting down Hugo will require Western Farmers to eliminate more than 80 full-time jobs. In addition to causing significant disruptions to the community and to Western Farmers' employees and their families, these reductions will increase the cost of near-term labor. Labor costs are higher for positions that are due to be eliminated. Thus, Western Farmers will need to pay its current employees retention

compensation or will need to pay a premium to hire contractors to continue operating Hugo due to the looming shutdown the Final Rule requires.

21. *Fuel supply costs*. If Hugo is to shut down at the end of 2032, the short-term price for its coal supply is likely to increase. That is because the supplier has its own costs to address. If the supplier is losing a major purchaser in the next decade, some of its payments will likely need to be accelerated. The mine will pass these costs on to Western Farmers in the form of higher prices for coal, which will ultimately fall on consumers. Similarly, Western Farmers will need to depend on natural gas to fuel the combustion turbines that it must construct to replace the power from Hugo. But natural gas prices are much more volatile than coal prices. This requires Western Farmers to plan for both higher prices and higher price variances, and these costs once again must ultimately be passed on to consumers.

ABSENT A STAY, WESTERN FARMERS WILL SUFFER IMMEDIATE IRREPARABLE HARM

22. *Immediate replacement power costs*. Western Farmers would need to replace at least 400 MW of reliable dispatchable generation from Hugo as a result of the Final Rule. Renewable energy sources (such as wind and solar)

cannot satisfy that demand. Renewables are an intermittent resource that Western Farmers cannot rely on for constant reliable dispatchable generation. Placing such a high level of dependence on renewables is a grid reliability disaster if, for example, people need power to heat their homes at nighttime (no solar) and in calm conditions (no wind). Thus, for replacement power, Western Farmers must turn to natural gas. Yet today's state-of-the-art natural gas combined cycle units cannot achieve the 90% CCS that the Final Rule demands. Even if those units could achieve 90% CCS, constructing one would cost *at least* hundreds of millions of dollars.

23. Thus, to replace the losses associated with Hugo's retirement, Western Farmers must rely on small combustion turbines. But to bring these assets into its portfolio by the Final Rule's deadlines, Western Farmers does not have time to spare. Equipment and labor lead times are already drawn out and will only grow longer as a result of the Final Rule. Design, permitting, and siting all take years to complete—even when everything goes according to plan. As a result, Western Farmers must immediately begin the process of securing replacement generation.

24. *Immediate retirement commitments*. The Final Rule requires Western Farmers to make a legally binding commitment for any retirements sometime within the next two years, before state implementation plans are due. Yet that is not the only notification that Western Farmers must make. Indeed, Western Farmers also must notify the Southwest Power Pool ("SPP") which is the regional transmission organization for Western Farmers. The timelines for these notifications have been accelerating, as regional transmission organizations across the country become concerned about the reliability impacts of taking massive amounts of reliable dispatchable generation off the grid all at once—which is exactly what the Final Rule will cause.

25. *Immediate workforce disruptions and costs.* Announcing the closure of Hugo will have immediate impacts on Hugo's workforce. For example, Western Farmers will need to begin immediately diverting resources in order to cover costs such as employee incentive plans and premium wages for contractors.

26. *Immediate costs to Western Farmers' members and consumers.* All of these near-term costs will begin flowing to Western Farmers' members—and ultimately to the rural consumers who depend on Western Farmers to keep their lights on when it is dark and to keep their heaters on when it is cold.

27. These costs are not recoverable. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded. Legally binding retirement promises cannot be undone.

28. These costs cannot be deferred or delayed until the courts reach a final ruling on the merits of NRECA's Petition for Review. Optimistically, Western Farmers expects this litigation to take *at least* 5 years (indeed, it took 7 years to litigate the Clean Power Plan). But the Final Rule does not give Western Farmers that much time to spare. For one thing, the Final Rule's one-year compliance extension mechanism is available only if Western Farmers "has made all reasonable efforts to achieve timely compliance" and "has acted consistent with achieving timely compliance." 89 Fed. Reg. 607. In other words, Western Farmers must act *now* in order to preserve its ability to claim the Final Rule's compliance extension mechanism (assuming that

extension is even included in the State plans that will govern Western Farmers). For numerous other reasons, too, haste is of the essence.

29. *Supply chain delays*. Original equipment manufacturers are already inundated with new purchase orders from electric utilities based on reliability purchases caused by an influx of non-dispatchable renewable resources all across the country. The Final Rule will only inundate these original equipment manufacturers even more and push delivery dates out even further. For example, lead times for new CTs are *already* 2-3 years long. Those waits will only grow if the Final Rule takes effect. This creates a "race" among electric utilities that need to order new equipment, each one hoping to be nearer the front of the queue. Western Farmers is not immune to that dynamic. Thus, Western Farmers has no choice but to begin purchasing equipment before the courts can adjudicate NRECA's challenge to the Final Rule on the merits.

30. *Labor market delays*. Complying with the Final Rule will require Western Farmers to hire swarms of consultants, engineers, attorneys, and other professionals to manage the vast amounts of design, modeling,

permitting, and other work required under the Final Rule—not only to achieve replacement power, but also to comply with all the requirements that apply to shutting down a plant such as Hugo. Yet these markets are also subject to the laws of supply and demand. These same consultants, engineers, attorneys, and other professionals are also in high demand from other sectors of the economy like transportation, oil and gas, etc. As electric utilities across the Nation rush to hire the same professionals, prices will increase. Accordingly, electric utilities must move early—not only to insulate themselves from price pressures, but also in an attempt to ensure that the needed professionals are even available.

31. *Financing delays*. On top of the delays that EPA has already discussed in the Final Rule, Western Farmers must factor in financing delays. The Final Rule will require Western Farmers to make major capital investments in replacement power. The U.S. Department of Agriculture ("USDA") Rural Utilities Service ("RUS") has historically helped cooperatives obtain and secure financing, with the mission of electrifying and maintaining critical infrastructure in rural America. Obtaining RUS

financing is a multi-step process. During project development and prior to construction, the project engineering team must prepare initial scoping and draft a project justification for the projected dollars to be spent. This process involves reaching out to third-party vendors to confirm cost estimates, design, and operational specifications. RUS must approve the Work Plan.

32. *NEPA delays*. RUS financing also requires compliance with the National Environmental Policy Act ("NEPA") and the National Historic Preservation Act, which adds additional time at the beginning of a large project and is subject to judicial review. USDA regulations set forth the procedures that RUS follows when conducting environmental reviews. The environmental review requirements are set forth by NEPA, which requires all federal agency actions or approvals go through a standardized environmental review process to evaluate what effect their proposed actions (*i.e.*, projects) would have on the environment. RUS may require development of Environmental Reports for certain Categorical Exclusions, Environmental Assessments, or Environmental Impact Statements, depending on the complexity and scale of the project.

33. The White House Council on Environmental Quality recently issued a new NEPA "Phase 2 Rule," which makes extensive regulatory changes and layers on numerous new requirements that will inject additional uncertainty and delays into the NEPA process. Still, even without the latest regulations, the environmental review process and timelines depend upon the scope of the project and ultimately upon what project documents RUS will request that the cooperative submit. It is impossible to know in advance exactly what these requests will be, which again incentivizes Western Farmers to act quickly to secure replacement power.

34. Borrowers must wait for the conclusion of RUS's environmental review before taking major actions on projects or obtaining RUS financial assistance. While other financing options may be available for certain types of projects, the interest rates are significantly higher. Western Farmers is a not-for-profit cooperative, and its consumers are in rural communities. Both are very sensitive to rate increases. Western Farmers regularly depends on RUS to help finance environmental compliance and other projects. This

process *alone* can take at least two years—and even longer if the NEPA review is subject to a litigation challenge.

35. In sum, if the Final Rule remains in effect while NRECA's challenge to the Final Rule is pending, Western Farmers will have no choice but to incur large, unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 9th day of May, 2024, in Anadarko, OK.

Justin Soderberg

Justin Soderberg

Appendix 13

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION,	)	
Petitioner,	)	
v.	)	Case No. 24-1122
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,	)	
Respondents.	)	

DECLARATION OF ROBERT C. HOCHSTETLER

I, Robert C. Hochstetler, declare as follows:

1. My name is Robert C. Hochstetler. I am the President and Chief Executive Officer of Central Electric Power Cooperative, Inc. ("Central Electric"), and have held that position since July 2014. I hold a Bachelor of Science degree in Electrical Engineering and four Master's degrees in Business Administration, Statistics, Strategic Management, and Public Administration. I have been employed in the electric utility industry since 1990, working for investor-owned utilities and electric cooperatives. Over the course of my career, I have managed various electric utility generating

assets, including coal and natural gas units as well as renewable generation. I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. Central Electric is a member of the National Rural Electric Cooperative Association ("NRECA"). This declaration is submitted in support of the legal challenges to the Environmental Protection Agency's final rule 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*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule"). I am familiar with Central Electric's operations, including power supply, transmission, compliance, workforce management, and electric markets in general. I also am familiar with how EPA's Final Rule will affect

Central Electric as well as its suppliers, members, members' consumers, and employees.

3. Central Electric is a not-for-profit generation and transmission cooperative owned by its members, the nineteen distribution cooperatives that operate in South Carolina. Central Electric provides wholesale electric service to its nineteen member cooperatives using more than 800 miles of transmission lines. Central Electric members provide service in all 46 of South Carolina's counties through 76,000 miles of distribution lines. Central Electric currently provides approximately 20,000,000 megawatt hours ("MWh") of energy to its members annually with a peak demand of approximately 4,600 megawatts ("MW").

OVERVIEW OF THE FINAL RULE

4. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam units, under Section 111(d). 89 Fed. Reg. at 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* at 39902. Both existing and new units must meet emissions limits roughly equal to what EPA says 90% carbon-

capture-and-sequestration can achieve. Existing units that cannot achieve this must shut down. New units that cannot achieve this must drastically reduce their output of electricity.

5. *Existing coal-fired units*. The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *Id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

6. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can

permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

7. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent"—*i.e.*, transforming a coal unit into one that combusts both coal and natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

8. Third, units that make a federally enforceable commitment to permanently cease operating before January 1, 2032, have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

9. *New gas-fired combustion turbine units*. For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* at 39908.

10. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* at 39917. "Intermediate load" units (those that sell 20-40% of their potential electric output) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO 2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

IMPACTS OF THE FINAL RULE ON CENTRAL ELECTRIC

11. As President and CEO of Central Electric, I am responsible for planning for the power supply needs of Central Electric and its members.

12. Central Electric has used several different sets of assumptions to project its system's demand for energy and capacity through 2050, all as part of its planning process. Regardless of the assumptions used, the projections show demand for capacity and energy will increase significantly. Central Electric anticipates that dramatic growth in near-term demand is likely, based on a number of announced manufacturing projects, a significant amount of which are electric transportation projects, including manufacturing plants to build electric vehicles and the batteries that will power those vehicles. Many, but not all, of these projects will be served by the electric cooperative members of Central Electric.

13. These major projects will generate smaller spin-off projects that will also be in territory served by electric cooperatives. These projects represent substantial investments in South Carolina that will produce high quality jobs, generate revenue for local governments and school districts,

and allow South Carolina to participate in "electrifying the economy"—thereby reducing carbon emissions. One such project, Redwood Materials, has announced it is investing $3.5 billion in an electric cooperative-served facility to recycle, refine and manufacture 100,000 MWh of cathode and anode components per year.

14. Data centers represent another industry driving the growing demand for electricity. Data centers consume large amounts of electricity and represent significant investment in the local economies where they operate. Central Electric's members have contracted to provide a significant amount of power to data centers to satisfy the ever-growing generation, use and storage of critical business information.

15. Specifically, QTS has announced a $1 billion investment in a facility under contract to be served with several hundred megawatts by York Electric Cooperative. Another data center project under contract to be served by Aiken Electric Cooperative will require an additional 200 MW. Manufacturing and data center projects currently actively considering locating or expanding in electric cooperative-served areas of South Carolina

would require more than 2,000 additional MW. However, to reap the benefits associated with these projects, Central Electric and its members must be able to commit to serve them with a dependable supply of reliable, firm electricity capacity.

16. Central Electric does not generate electricity. It contracts with wholesale suppliers of electricity on behalf of its member cooperatives to meet their short- and long-terms needs. The vast majority of its electric capacity is acquired through two long-term power purchase agreements with the South Carolina Public Service Authority ("Santee Cooper") and Duke Energy ("Duke"). Santee Cooper and Duke currently rely in part on coal-fired base load generation to meet the needs of their customers, including Central Electric. Both Santee Cooper and Duke have plans to retire existing coal generation plants and to replace the generation from those plants in part with natural gas fired combined cycle generating units. The Duke plan includes the retirement of 6.2 gigawatts ("GW") of coal generation and the replacement of that generation with a variety of cleaner assets, including 2.4 GW of combined cycle generation. Santee Cooper's retirement

of coal and addition of combined cycle generation is part of its plan to reduce its carbon emissions by the mid-2030s to 44% of its 2005 CO_2 emissions level.

17. The other major utility operating in the state, Dominion Energy South Carolina, is planning to close its two remaining coal plants by 2030 and to replace the generation provided by those units with a variety of cleaner generation units, including a critically important combined cycle plant. As discussed further below, CCS is not an option for these plants. And the Final Rule's non-CCS options would all add overwhelming expense to these plants (as would CCS itself, if it were even possible). Thus, regardless of what path these plants choose, they will face massive compliance costs, and they will need to pass those costs on to Central Electric and other buyers.

18. My staff and I at Central Electric have followed closely the efforts of our wholesale providers to manage their generation resources to retire coal generation and replace it with cleaner generation while maintaining the reliability and affordability of their service. We have reviewed regulatory filings made by the companies in their Integrated Resource Plans and other regulatory filings. Based on our review of their filings, we are aware that

Santee Cooper and Duke are planning, over the next few years, to greatly increase their deployment of, and reliance on, renewable resources. However, we are convinced that without the addition of the combined cycle units they plan to add, neither of our major wholesale suppliers will be able to: (1) retire existing coal generation on their planned schedules; (2) maintain the reliability and affordability of their service; and (3) meet the increasing demand for capacity and energy that they and Central Electric are facing. The combined cycle units will provide reliable and dispatchable base load generation that is simply not available from other resources.

19. South Carolina utilities, including the electric cooperatives, generally experience our highest electricity demands during the winter months due to a prevalence of heat pumps with auxiliary heat provided by resistance heating elements on the coldest days. Over the past several years, South Carolina utilities have struggled to supply sufficient electricity to loads during the coldest hours of winter. During Winter Storm Elliott in December 2022, Duke Energy Carolinas, Dominion Energy South Carolina,

and Santee Cooper all implemented rolling blackouts in order to match resources to high loads and avoid widespread cascading outages.

20. Given the recent addition of new loads and the anticipated addition of more new loads in the next several years, without the addition of new, always available generation, the utilities in South Carolina will likely be incapable of providing generation to match demand during peak periods. This failure to meet projected demand would cause rolling blackouts.

21. South Carolina has limited import capability for additional, firm electricity capacity and energy. Historically, utilities in the state have built, owned, and maintained their own generation resources with little reliance on imports of firm power from other, non-system resources. The availability of transmission import capability from adjacent systems coincided with the utilities' need to be connected to the North American power grid to provide real-time, reliable service. It was not intended to provide long-term, substantial import capability in lieu of in-state generation resources. Firm electricity imports have grown over the past several years such that additional firm import capacity is now limited.

22. South Carolina has experienced a substantial increase of solar photovoltaic generation over the past decade or more, and utilities have plans to install additional solar resources. However, land use concerns, supply chain delays, and solar energy's inherent mismatch with the timing of loads on the system make solar a valuable, albeit niche, resource. Solar energy can help offset fossil generation during opportune times, reducing carbon emissions, but it cannot currently provide the generation capacity required during cold winter morning peak periods in the state.

23. On-shore wind generation is not an option in South Carolina due to the lack of sustained, viable wind resources in the state. While offshore wind generation could be promising in the decades to come, it is not a viable, commercially available or reasonable alternative in the foreseeable future. Offshore wind also faces political opposition from state leaders who, recognizing that South Carolina's No. 1 industry is tourism, want to keep turbines away from the state's coast.

24. It is critically important that South Carolina's utilities move forward immediately with efforts to construct new combined cycle units.

The demand growth that Central Electric expects to experience requires that these utilities move with haste. The process of planning, siting and constructing these plants is difficult and time-consuming. It must begin in the very near future for the plants to come online in time to meet the demands of South Carolina residents and industry.

25. It is because of our understanding of the importance to our wholesale suppliers of their ability to add natural gas combined cycle generation that my team and I are so concerned about the Final Rule.

26. The adoption of carbon capture and sequestration ("CCS") as the "best system of emissions reduction" is flawed and could have devastating consequences for South Carolina electric utilities, including Central Electric and its member cooperatives.

27. My team has studied CCS and has concluded that while the technology may one day in the future be helpful in reducing carbon emissions, it is not remotely ready for deployment in South Carolina in a time frame necessary to meet our needs.

28. There are no CCS projects of any kind in our state or region, and there are no CCS projects for natural gas generation anywhere. No one has even seriously begun the process of determining whether CCS is feasible in our region. The most obvious hurdles are the lack of storage and the lack of transport. Because operators in our region view these challenges as insurmountable, they have not even investigated the technological requirements for CCS.

29. There is no existing infrastructure for CCS in South Carolina and no plan for the permitting and construction of the pipelines that would be necessary to transport carbon dioxide to locations where CCS is feasible, if such locations can be identified. Based on the limited information that is available, it appears that the geology of our area would not be suitable for CCS. Current CCS facilities in Louisiana and Mississippi are either at capacity or oversubscribed. Pipeline permits to any available CCS facility is very difficult to obtain, and it is unreasonable to expect such pipelines could be permitted and constructed in the required time frame.

30. We have no reliable information that we can use to calculate cost estimates for attempting to construct a natural gas CCS project, because one has never been constructed. Based on what we know, it appears likely that adding CCS to a natural gas generation project, if it is even feasible, would greatly increase the project's cost—thereby greatly increasing the impact on the people we ultimately serve, the members of Central Electric's member retail distribution cooperatives.

31. Our member cooperatives serve mostly rural parts of South Carolina, and many of their members live in poorly insulated homes and struggle to pay their current power bills. Central Electric is focused on providing those consumers electricity at reasonable rates. The requirement to implement CCS at this point in its development is irresponsible in its disregard for the likely financial impact on our end-user members.

32. The determination that CCS is the best system of emissions reduction and thus must be implemented for any new natural gas projects is flawed and unsupported by engineering and economic analysis. In addition, it will have adverse consequences for the efforts of South Carolina utilities

to reduce carbon emissions and will thwart the efforts of South Carolina to participate in transitioning to a cleaner economy with new electric vehicle and battery manufacturing projects. Without the ability to proceed now with planning and permitting new natural gas combined cycle projects, South Carolina utilities will not be able to move forward with plans to retire coal generation units and maintain the reliability of their service.

33. The uncertainty caused by the Final Rule will make it difficult for Central Electric and other South Carolina utilities to commit to serving the planned economic development projects, including electric vehicle and battery manufacturers, that continue to boost the state's economy.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing to be true and correct to the best of my knowledge.

Executed on this 9th day of May, 2024, in Columbia, SC.

Robert C Hochstetler

Robert C. Hochstetler

Appendix 14

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION,	)	
Petitioner,	)	
v.	)	Case No. 24-1122
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,	)	
Respondents.	)	

DECLARATION OF KARI HOLLANDSWORTH

I, Kari Hollandsworth, declare as follows:

1. My name is Kari Hollandsworth. I am the President & Chief Executive Officer ("CEO") at Golden Spread Electric Cooperative, Inc. ("Golden Spread"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have 26 years of experience in the electric utility industry. I have been employed at Golden Spread since 2009. Over the last 15 years at Golden

Spread, I have served in multiple roles, including Energy Analyst, Resource Planning Administrator, Electric Trading Manager, Director of Finance, Forecasting and Risk, and Vice President of Commercial and Asset Operations. I currently serve on the Oklahoma Association of Electric Cooperatives, Inc. Board, the Alliance for Cooperative Energy Services Power Marketing LLC ("ACES") Board, and the National Renewables Cooperative Organization ("NRCO") Board. I also serve as the Women in Science Endeavors (WISE Program) treasurer. Previously, I worked at Xcel Energy for 11 years. I hold a bachelor's degree in economics and business management from Cornell University, Ithaca, New York.

3. As President & CEO at Golden Spread, I have ultimate responsibility for providing Golden Spread's distribution cooperative member ("Member") systems with an economical and reliable power supply and support services. I am responsible for providing strategic leadership for Golden Spread by working with the Executive Team and Board of Directors to establish short and long-term goals, financial plans, strategies, and policies to ensure the long-term success of Golden Spread. I have ultimate

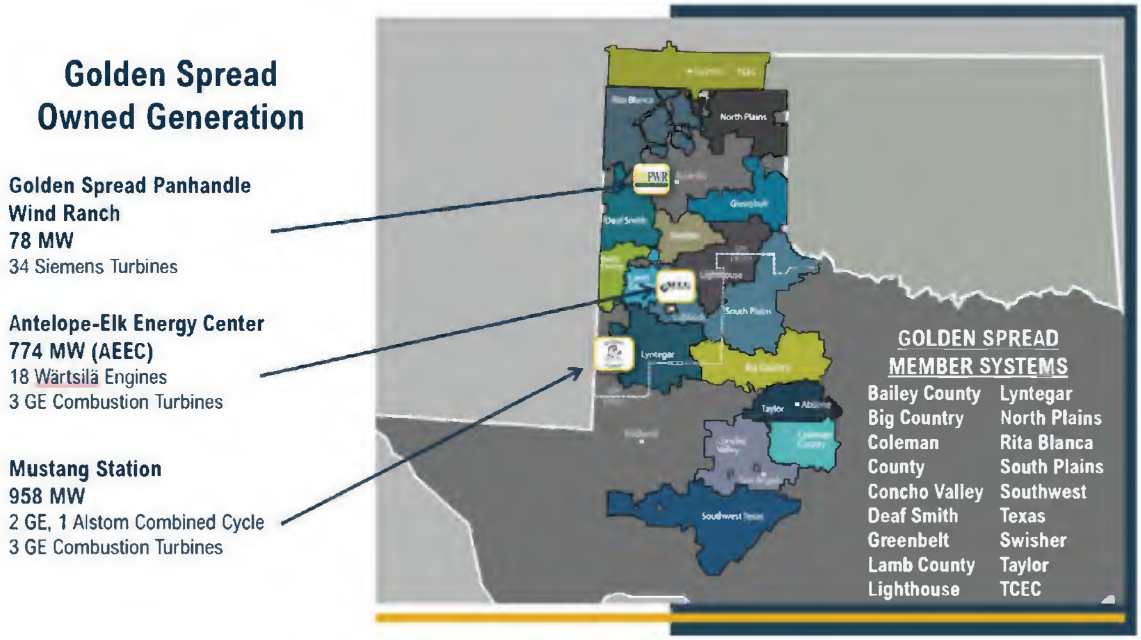
responsibility for directing the generation and transmission of electricity to meet Member system demand; informing and involving Member-owners; ensuring strong financial planning and flexibility; ensuring compliance with all applicable industry state and federal laws and regulations; identifying and managing the risks of Golden Spread's business; developing and maintaining strategic networks; and representing Golden Spread on a local, regional and national level.

4. Golden Spread is a member of the National Rural Electric Cooperative Association ("NRECA"). This declaration is submitted in support of NRECA's Petition for Review and Motion for Stay of EPA's final rule 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*, 89 Fed. Reg. 39802 (May 9, 2024) (the "Final Rule"). I am familiar with Golden Spread's operations, including generation and transmission, compliance, workforce management, and electric markets in general. I am

also familiar with the Final Rule, and I am familiar with how the Final Rule will affect Golden Spread as well as rural electric cooperatives in general.

5. Golden Spread is a non-profit electric generation and transmission cooperative headquartered in Amarillo, Texas. Its purpose is to supply reliable wholesale electric power at the lowest feasible cost to its 16 not-for-profit distribution cooperative 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.

6. Golden Spread owns and operates power plants located in both the Electric Reliability Council of Texas ("ERCOT") and the Southwest Power Pool ("SPP"). The figure below shows the location of Golden Spread's electric generating units and its Member Cooperatives' service territories.



7. Not-for-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 in 1936, which provided funding for rural electrification. Before the Rural Electrification Act, electricity was commonplace in cities but not so in rural areas, where population densities and incomes were too low to attract for-profit utilities. Rural America was largely ignored as the focus was on more densely populated areas with higher expected revenues. The Rural Electrification Act gave rise to the not-for-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, electric cooperatives have generated the electricity that has powered rural America's economic development.

8. Cooperatives serve 92% of the nation's persistent poverty counties. 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 either entirely or partially designated as disadvantaged communities according to the U.S. Climate Resilience Toolkit.

9. 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's ERCOT region, 28% of the energy generated in 2021 came from wind and solar (more than twice the national percentage). This percentage increased to 31% in 2022. In the SPP region, 37.5% of the generation produced in 2022 came from wind. As a state, Texas leads the nation in wind-powered electricity generation, producing more

than one-fourth of the nation's total wind power. 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. Texas also has the second largest percentage share of total utility-scale solar electricity generation, at 15%. These levels of wind and solar are expected only to increase in the future.

10. With an expected increase in the reliance on wind and solar energy, the risk of sudden losses of generation necessarily rises with it as these resources are intermittently unavailable. Alternative generation resources must be in place to quickly maintain grid stability and serve load when weather conditions are not conducive to wind and solar energy production. The risk of sudden losses of generation rises with the expansion of renewables, because the availability of wind and solar is highly variable and is difficult to predict. Non-wind energy sources must be available to quickly make up for the loss in wind energy production to maintain reliability and the continued viability and growth of renewables.

11. While the region in which Golden Spread operates has abundant wind, solar, and land resources, water resources are severely limited. The

region has historically suffered from persistent drought conditions, and surface water is scarce due in part to low precipitation. 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% 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. One of the reasons carbon capture and storage ("CCS") is not technically or economically feasible for Golden Spread is because of water scarcity.

12. 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. Due in part to the high wind and solar availability (and the potential for more) in its service area, Golden Spread has pursued a strategy to invest primarily in natural-gas simple-cycle units to support the growing renewable generation and limited water resources in the region.

13. Golden Spread's assets include: (A) a natural-gas-fired combined-cycle unit and three simple-cycle units located at its Mustang Station in Denver City, Texas; (B) eighteen natural-gas-fired reciprocating internal combustion engines and three fast-starting simple-cycle units located at its Antelope Elk Energy Center in Abernathy, Texas; and (C) thirty-four wind generators located at Golden Spread Panhandle Wind Ranch near Wildorado, Texas. Golden Spread does not own or operate any coal or oil-fired units. As part of its goal to meet its Members' energy needs, Golden Spread regularly evaluates whether it needs to develop new resources.

OVERVIEW OF THE FINAL RULE

14. The Final Rule sets carbon dioxide ("CO_2") emissions limits that States must apply to existing coal-fired steam electric generating units, under Section 111(d). 89 Fed. Reg. 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* at 39902. Both types of units must meet emissions limits equal to what EPA believes 90% carbon-capture-and-sequestration can achieve. Existing coal-fired steam units that cannot achieve this must shut down. New gas-fired

combustion-turbine units that cannot achieve this must drastically limit their output of electricity.

15. Of particular relevance to Golden Spread, for new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* 39908.

16. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* 39917.

17. "Intermediate load" units (those that sell 20-40% of their potential electric output) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.*

18. "Base load" units (those sell more than 40% of their potential electric output) must comply with a "multi-phase standard of performance." *Id.* 39923. Phase I is "based on the performance of a highly efficient combined cycle turbine" and has "an immediate compliance date." *Id.* 39903. Phase II is based on 90% CCS and has "a compliance date of January 1, 2032." *Id.*

IMPACTS OF THE FINAL RULE

I. The Final Rule will hurt the continued development of renewable resources.

19. EPA's Final Rule limiting new, low-load simple-cycle units to an artificially low capacity factor ignores the continuing importance that these units have for grid reliability and efficiency—particularly given the increase in renewable energy. Simple-cycle units play a necessary and established role in the support of intermittent renewable generation because of their "fast start" and ramping capabilities. That role will only become more critical as wind generation is increasing at unprecedented levels throughout the country, particularly in wind rich regions like Texas.

20. Golden Spread has direct experience in seeing how simple-cycle units make the growth of renewables possible. The Energy Information Administration ("EIA") has recognized the same thing: "Electric grid operators can use [simple-cycle units] 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. [Simple-cycle units] can meet demand if there is a lull in

wind or solar output. [Simple-cycle units] can best provide grid support because they can produce 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 [combined-cycle] or steam boiler plants, can take two to three times longer than [simple-cycle units] to start and ramp up to full load."[1] In other words, as more renewables become available, the more simple-cycle units and other quick-start fossil-fuel generation are needed for grid support. And that makes sense. Renewables are a variable resource. When they are not available, the shortfall is much more drastic if renewables are 40% of the grid than if they are 5% of the grid.

21. 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

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[1] U.S. Energy Information Administration, *U.S. simple-cycle natural gas turbines operated at record highs in summer 2022* (Mar. 1, 2023), https://tinyurl.com/5374p37p

Report."[2] NERC observed that combustion turbines are "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."[3] NERC has also raised concerns regarding the aggregate impact of battery resources, noting that it was analyzing "large-scale grid disturbances involving common mode failures in [battery]-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."[4]

22. NERC's analysis 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.

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[2] NERC, *2022 State of Reliability* (July 2022), https://tinyurl.com/3bc5kdp4.

[3] *Id.* at viii.

[4] NERC, *Industry Recommendation, Inverter-Based Resource Performance Issues* (Mar. 14, 2023), https://tinyurl.com/5b7uwasb.

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."[5]

23. NERC's report demonstrates the complexity of this interdependence between renewables and grid-support resources, 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.

24. The Final Rule does not consider the full gravity, complexity, and importance of the grid capacity, reliability, and affordability issues described by NERC that are affected by the Final Rule. EPA is not merely setting emissions standards. Rather, the Final Rule will significantly affect the structure and operation of the grid, including the interdependency of key elements of the grid that are necessary to provide reliable and affordable electricity to the public. The Final Rule is also based on assumptions about

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[5] NERC, *2022 State of Reliability*, at 45.

the availability, interoperability, and affordability of power generation and storage technology about which EPA has no expertise and little experience.

25. Simple-cycle 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 the Final Rule. Restricting the use of simple-cycle units by imposing an artificial capacity limit will disrupt the relationship between natural gas and renewable electric generating units, may actually limit renewable generation, and in some cases may increase—not decrease—emissions (due to the predictable curtailment of renewables).

II. CCS is not an "adequately demonstrated," technology and emissions limits based on CCS are not "achievable."

26. Golden Spread has specific knowledge regarding the ability to achieve emissions limits relying on CCS for its combined-cycle units. Golden Spread's Mustang Combined Cycle facility was the subject of a CCS feasibility study conducted by the University of Texas and funded in part by the Department of Energy. 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 combustion turbine facility included a service area with low renewables, combustion turbines operating at a high capacity, and plentiful water.

27. Thus, CCS is not a feasible option in Golden Spread's service area precisely because the already high penetration of renewables that are supported by Golden Spread's combustion turbines. Regardless of the technology EPA speculates might someday 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 renewables is only going to increase.

28. 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 simple-cycle units, such as Golden Spread's, that operate in regions with high renewable generation and limited water availability. Thus, EPA's Final Rule imposing CCS on any simple-cycle unit that exceeds a 40% capacity factor is neither demonstrated nor achievable.

III. The Final Rule's restrictions on low-load simple-cycle units will hurt reliability and efficiency.

29. Restricting the availability of low load simple-cycle units will force operators to rely on less efficient alternatives that could result in curtailments of renewable power and even increased emissions (relative to expectations). Combined-cycle units typically require several hours to be at full load and optimum heat rate, from a cold state, and the boiler is adversely impacted by frequent cycling. Therefore, combined-cycle units are not well suited to efficiently and consistently backup intermittent generation from renewables, such as wind and solar. The frequent cycling and ramping up and down of combined-cycle units causes thermal stresses on plant equipment and components, which increases maintenance costs and decreases the overall efficiency of the unit. Simple-cycle units equipped with heat recovery steam generators for purposes of steam injection face similar complexities.

30. Combined-cycle units can practically supplement intermittent energy sources only if they are brought online 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.*, combined-cycle units or intermediate load simple-cycle units with steam injection) can stay online at minimum output and dispatched, to be readily available when the wind drops off or there is no sunshine. When combined-cycle 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 combined-cycle units operating at stand-by capacity requires that power from some other source, *e.g.*, wind, be curtailed.

31. Thus, under the Final Rule's requirement that simple-cycle units must operate at a limited capacity factor, operators are forced to keep less-flexible alternatives, such as combined-cycle units, running and available to prepare for the loss of solar and wind in the evening. Using these alternatives that are less flexible than low-load simple-cycle units has the unintended

consequence of forcing curtailments of renewable energy and potentially increasing CO_2 emissions.

32. For combined-cycle units 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 combined-cycle units.

33. Thus, in areas with high wind capacity (such as the region served by Golden Spread), reducing the availability of low-load simple-cycle units and relying on combined-cycle units can decrease generation by renewables and cause an increase, rather than a decrease, of expected CO_2 emissions. The fast-start flexibility provided by simple-cycle turbines on a grid-wide basis results in greater integration of renewable resources into the grid.

34. Simple-cycle units that are available to quickly and economically operate without arbitrary limits are an essential part of operating an electric grid with significant renewable energy penetration and will be for the foreseeable future. Combined-cycle units are not economically or environmentally suitable alternatives to low-load simple-cycle units. This role cannot be technically or economically assumed by battery power on anything near the scale and schedule contemplated in the Final Rule.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 13th day of May, 2024, in Potter County, Amarillo, Texas.

Kari Hollandsworth

Kari Hollandsworth
President & Chief Executive Officer
Golden Spread Electric Cooperative, Inc.

Appendix 15

BASIN ELECTRIC
POWER COOPERATIVE

A Touchstone Energy® Cooperative

COMMENTS ON:

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)

SUBMITTED ELECTRONICALLY TO THE ENVIRONMENTAL PROTECTION AGENCY

DOCKET NO. EPA–HQ–OAR–2023–0072

AUGUST 8, 2023

Table of Contents

Glossary of Terms and Abbreviations

AC	Alternating Current
Act	Clean Air Act
BSER	Best System of Emission Reduction
CAA	Clean Air Act
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
DC	Direct Current
DOE	Department of Energy
EGU	Electric Generating Unit
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GE	General Electric
IIJA	Infrastructure Investment and Jobs Act
IPA	Intermountain Power Agency
IRA	Inflation Reduction Act
kW	Kilowatts
MATS	Mercury and Air Toxics Standards
MISO	Midcontinental Independent System Operator
MMBTU	One Million British Thermal Units
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory

NGCC	Natural Gas Combined Cycle
NOx	Oxides of Nitrogen
NNSR	Nonattainment New Source Review
NSR	New Source Review
NWPP	Northwest Power Pool
PM	Particulate Matter
PSD	Prevention of Significant Deterioration
RMRG	Rocky Mountain Reserve Group
SPP	Southwest Power Pool
TPY	Tons Per Year

I. INTRODUCTION

Basin Electric Power Cooperative ("Basin Electric") appreciates the opportunity to comment on the Environmental Protection Agency's ("EPA") 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, 88 Fed. Reg. 33,240 (May 23, 2023) (Docket No. EPA–HQ–OAR–2023–0072) (the "Proposed Rule"). As expressed in Basin Electric's requests for an extension of time,[1] EPA has not provided the regulated community adequate time to review, analyze, and provide meaningful comment on a rulemaking that will have disproportional impacts on cooperatives like Basin Electric that continue to rely on a diverse portfolio, including coal-fired generation, to meet surging demand within their customer base.[2]

II. EXECUTIVE SUMMARY

A. Basin Electric's Interest in the Proposed Rule

Basin Electric is a not-for-profit generation and transmission cooperative owned by 141-member cooperative systems. Basin Electric provides wholesale power to its members in nine States, with electric generation facilities in North Dakota, South Dakota, Wyoming, Montana, and Iowa serving approximately 3 million customers. It has a diverse energy portfolio consisting of coal, gas, oil, distributed, and renewable energy. Basin Electric knows that an all-of-the-above energy strategy, which takes advantage of the benefits of renewable energy development while maintaining a fleet of natural gas- and coal-fired baseload generation, is required to provide responsible, affordable, and reliable energy.

In the last decade, Basin Electric's load has grown by nearly fifty percent. Eighty percent of that load growth has been met with wind, natural gas, and market purchases. Basin Electric's current energy supply includes 2,858.5 megawatts ("MW") of coal, 1,775.4 MW of wind, and 1,493.7 MW of natural gas. Basin Electric also owns 2,526 miles, and maintains 2,565 miles, of high-voltage transmission line. By 2028, Basin Electric expects peak demand on its system to grow by 660 MW and energy consumption to grow by approximately 4.3 million MW hours.

Even as Basin Electric drives towards a more diversified portfolio and the market continues to shift towards renewables, coal and gas remain a critical piece of Basin Electric's power generation puzzle. In North Dakota, Basin Electric owns and operates two lignite-based facilities: the Leland Olds Station (two units) and the Antelope Valley Station (two units). In Wyoming, Basin Electric owns the Dry Fork Station (one unit) and is part-

[1] Basin Electric's Request for Extension (June 7, 2023) (Document No. EPA-HQ-OAR-2023-0072-0089); Basin Electric's Request for Extension (July 20, 2023) (Document No. EPA-HQ-OAR-2023-0072-0175).
[2] As a rural electric power cooperative with western operations, Basin Electric incorporates by reference the comments of the National Rural Electric Cooperative Association and West Associates.

owner and operator of the Laramie River Station (three units). In South Dakota, Basin Electric owns and operates the Deer Creek Station natural gas combined cycle ("NGCC") generating station. In Iowa, Basin Electric is part owner of the Earl F. Wisdom natural gas and oil electric generating facility. Basin Electric also owns and operates more than a dozen smaller natural gas simple cycle and oil-fueled peaking stations.

Additionally, Basin Electric has developed a robust green and renewable energy portfolio in excess of 2,100 MW. Basin Electric has hundreds of megawatts of wind generation in North Dakota and South Dakota. Finally, Basin Electric's affiliate Dakota Gasification Company owns and operates the Great Plains Synfuels plant in North Dakota, which, among other things, operates the largest carbon dioxide ("CO_2") capture project in North America and has been exporting CO_2 for geologic sequestration in Saskatchewan, Canada. Basin Electric's long-term plans include reliance on well-controlled coal-fired generation as part of a diversified portfolio designed to provide reliable and affordable generation to its rapidly growing customer base.

B. Basin Electric will be Disproportionately Impacted by the Proposed Rule

The Proposed Rule will have a significant effect on Basin Electric's fleet of fossil fuel-fired power plants, affecting 2,817 MWs of coal-fired generation and 324 MWs of natural gas-fired generation. Basin Electric owns and operates four coal-fired power plants (8 units) that it has no intention to retire before 2040. Under the Proposed Rule, all of Basin Electric's coal-fired EGUs would need to install carbon capture and storage ("CCS") by 2030 capable of capturing 90 percent of CO_2 emissions. In addition, Basin Electric's natural gas combined-cycle Deer Creek Station will need to either install CCS by 2035 or co-fire low-greenhouse gas ("GHG") hydrogen (30% by 2032 and 96% by 2038). The consequences of the rule will be profound and could lead to the early, unplanned retirement of base load power—threatening energy reliability and increasing electricity costs.

Simply put, the Proposed Rule is unreasonable and infeasible. For numerous reasons, Basin Electric cannot comply with the proposed standards. To date, CCS for coal-fired power plants remains cost prohibitive, requires too great an energy load, and has not been shown to achieve 90 percent capture of all CO_2 emissions. The rule will require Basin Electric to spend billions of dollars to install an unproven emissions control system at all its coal-fired plants that is neither technically feasible for its facilities nor adequately demonstrated in the industry. This cost will increase the price of electricity and negatively impact Basin Electric's members and customers. Due to the significant parasitic load from CCS and Basin Electric's load growth, the Proposed Rule also threatens Basin Electric's ability to provide reliable energy. In addition, Basin Electric will not be able to design, permit and construct carbon capture systems at each of its existing coal-fired plants as well as the ancillary transportation and storage systems by 2030.

Pursuing low-GHG hydrogen co-firing for Basin Electric's natural gas-fired plants at the level and on the timeline in the Proposed Rule is similarly infeasible. Co-firing 30% hydrogen at Basin Electric's Deer Creek Station facility will require redesigning and retrofitting of the significant portions of the facility, if the turbines used at the facility are even capable of supporting such a retrofit. Additionally, the technology to combust greater than 30% hydrogen in the size of turbines used at Basin Electric's Deer Creek Station facility simply does not exist and EPA has not provided any meaningful timeline to achieve 96% co-firing by 2038. Given the significant engineering challenges required to achieve higher percentages of hydrogen co-firing, any projection of when 96% co-firing will be commercially viable is unreasonably speculative. Projecting when the infrastructure necessary to support both 30% and 96% co-firing across the industry will be secured is even more speculative. Entirely new industries of low-GHG hydrogen production, storage, and transportation will need to be developed at an unprecedented scale and pace to meet the implementation deadlines in the Proposed Rule. This will require Basin Electric to invest billions of dollars in speculative technology and to rely on hypothetical infrastructure development. If the necessary technology and infrastructure are not developed by the deadlines in the Proposed Rule, Basin Electric will be forced to close the Deer Creek Station facility and further invest in alternatives to make up for the significant loss in production. Accordingly, the Proposed Rule will threaten Basin Electric's ability to meet its contractual obligations to its customers.

C. Summary of Basin Electric's Comments to the Proposed Rule

EPA's third attempt to regulate GHG emitted by fossil-fuel fired electric generating units ("EGUs") under CAA Section 111 suffers from many of the same flaws as the 2015 Clean Power Plan. EPA's assertion that it has established the Best System of Emission Reduction ("BSER") for both new and existing sources by creating aggressive and arbitrary timelines by which nascent technologies "should" be available is not "adequately demonstrated" and would come at an exorbitant and unprecedented cost; fundamentally shifts power generation away from coal and natural gas in a manner that will imperil reliability and cost-efficient generation of electricity; and relies on development of technologies and vast infrastructure projects that are well outside EGU's fence lines. As discussed in greater detail below, EPA's Proposed Rule is premised on numerous false and inadequately supported assumptions.

- EPA's BSER determinations run afoul of the major questions doctrine and improperly regulates beyond the fence line of EGUs;

- EPA's proposed BSER requiring existing coal-fired EGUs (retiring beyond 2040) to capture 90% of all CO_2 emissions by 2030 is not adequately demonstrated and cannot support achievable emission standards. The capture technology remains in its infancy, is prone to operational issues, and has not been sufficiently demonstrated at commercial scale on coal-fired EGUs. In addition, the expansive infrastructure needed to transport and store the captured carbon does not exist and cannot be completed before 2030.

- CCS is exorbitantly expensive and requires too great of an energy load. Basin Electric's own experience demonstrates that CCS is currently infeasible and will increase electricity costs as well as threaten energy reliability.

- Neither of EPA's proposed BSER determinations for base load natural-gas fired EGUs (capture 90% of all CO_2 emissions by 2030 or co-fire 30% hydrogen by 2032 and 96% hydrogen by 2038) are adequately demonstrated and they cannot support achievable emission limitations. The technologies to implement carbon capture and hydrogen co-firing both require significant technical advancements before they are commercially viable at the scale required for base load facilities. Additionally, the unprecedented scale of infrastructure development required to support the widespread use of these technologies cannot be completed by the implementation dates in the BSER determinations.

- EPA failed to carefully consider energy requirements, including the maintenance of resource adequacy and grid reliability, when formulating the Proposed Rule. The early retirement of Basin Electric's coal-fired EGUs threatens the Nation's grid reliability because Basin Electric depends on a diverse energy portfolio, including renewable energy, to dispatch electricity in a reliable and cost-effective manner. Significant losses of dispatchable and reliable generating capacity resulting from coal-fired EGUs cannot be adequately replaced by renewables.

- EPA failed to analyze how grid reliability, energy production, and cost concerns will impact low-income and Native American communities throughout Basin Electric's service area. This failure violates Executive Orders mandating that EPA must account for and consider the impact of the Proposed Rule on such communities with potential environmental justice concerns.

III. LEGAL FRAMEWORK

Clean Air Act Section 111 provides for the regulation of stationary sources that, in EPA's judgment, "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[3] Section 111(b) addresses the regulation of emissions from new (including modified and reconstructed) sources, while Section 111(d) addresses the regulation of emissions from existing sources.

A. Section 111 Standard of Performance

The Clean Air Act directs EPA to determine federal standards of performance that apply uniformly to new and modified sources under Section 111(b). A standard of performance is defined 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

[3] 42 U.S.C. § 7411(b)(1)(A).

energy requirements) the Administrator determines has been adequately demonstrated.[4]

In addition to driving the federal standard of performance for new and modified sources, BSER "is the central determination that the EPA must make in formulating [its emission] guidelines" under Section 111.[5] The standard of performance also is relevant for regulation of existing sources under Section 111(d); however, EPA's role is more limited in the regulation of existing sources, as greater responsibility for such sources is reserved for the states. Pursuant to Section 111(d), it is the states that "establish standards for performance for any existing source" for air pollutants (such as GHG) that are emitted from listed source categories and are neither criteria pollutants nor hazardous air pollutants.[6] EPA regulations must permit the states, in applying standards of performance to specific sources, "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[7] These standards of performance are developed and submitted to EPA pursuant to EPA implementing regulations that establish a process like that used for state implementation plans under CAA Section 110.[8] Only if a state "fails to submit a satisfactory plan" does the Administrator have the authority to prescribe a plan for it.[9]

In December of 2022, EPA proposed implementing regulations for Section 111(d), titled "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)" ("Proposed Implementing Regulations").[10] The Proposed Rule states that EPA intends to finalize that rule prior to promulgating the emissions guidelines within the Proposed Rule.

Though the Proposed Implementing Regulations would require state plans to be submitted within 15 months after publication of a final emission guideline, for the emission guidelines in the Proposed Rule, EPA has proposed to supersede that timeline and instead require State plan submission within 24 months from the date of final publication.[11]

Pursuant to the Proposed Implementing Regulations, EPA has proposed threshold requirements which must be met before a state may consider "among other factors, the remaining useful life of the existing source to which such standard applies" ("RULOF").[12] Specifically, the Proposed Implementing Regulations specify three circumstances in which a state may set less stringent standards or longer compliance schedules: "(1) an 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 (or class of facilities) that are

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[4] *Id.* § 7411(a)(1) (emphasis added).
[5] *West Virginia v. EPA*, 142 S. Ct. 2587, 2607 (2022).
[6] 42 U.S.C. § 7411(d)(1).
[7] *Id.*
[8] *Id.*
[9] *Id.* § 7411(d)(2)(A).
[10] *See* 87 Fed. Reg. 79,176 (Dec. 23, 2022).
[11] 88 Fed. Reg. 33,240, 33,402 (May 23, 2023).
[12] 87 Fed. Reg. 79,176, 79,201 (Dec. 23, 2022).

fundamentally different from the information considered in the determination of the BSER in the emission guidelines."[13] Additionally, EPA proposed to interpret CAA section 111(d) as authorizing states to achieve the requisite emission limitation through the aggregate reduction of emissions, rather than requiring each individual source to meet the emissions limitation, including through trading or averaging.[14]

B. EPA's Determination of the Best System of Emissions Reduction

The "best system of emission reduction" ("BSER") is the foundational concept for the determination of the appropriate "standard of performance" under both CAA Section 111(b) and Section 111(d). As explained by the United States Supreme Court in *West Virginia v. EPA*, in devising emissions limits for power plants, EPA first "determines" the "best system of emission reduction" that—taking into account cost, health, and other factors—it finds "has been adequately demonstrated."[15] EPA must then quantify "the degree of emission limitation achievable" if that BSER were applied to the regulated source.[16] The BSER, therefore, "is the central determination that the EPA must make in formulating [its emission] guidelines" under Section 111.[17]

The D.C. Circuit Court of Appeals has established two primary but related requirements for any BSER adopted under both subsection (b) and (d) of Section 111: (1) the BSER must be "adequately demonstrated"; and (2) the standards of performance derived from the BSER must be "achievable."[18] Finally, EPA and states also must consider the statutory directive to consider costs, remaining useful life of the unit, as well as energy and environmental impacts.

1. *Technology Must Be Adequately Demonstrated*

The first element requires EPA to "adequately demonstrate[]" that the technology chosen as the BSER "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."[19] In other words, BSER under "Section 111 looks toward what may fairly be projected for the regulated future."[20]

Thus, where a BSER is based on projections of future availability of technology, the feasibility determination cannot be based on a "subjective understanding of the problem,"

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[13] *Id.* at 79,199.
[14] 88 Fed. Reg. 33,240, 33,392 (May 23, 2023).
[15] *West* Virginia, 142 S. Ct. at 2595.
[16] *Id.*
[17] *Id.* at 2607.
[18] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 430 (D.C. Cir. 1980) (quoting CAA Section 111(a)).
[19] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973); *Portland Cement Ass'n v. Ruckelshaus*, 486 F. 2d 375, 391 (D.C. Cir. 1973) ("While the technology does not have to be in regular use by existing sources, there must be an "'adequate[] demonstrat[ion]' that there will be 'available technology.'").
[20] *Portland Cement Ass'n*, 486 F.2d at 391.

"'crystal ball inquiry,'"[21] or "mere speculation or conjecture."[22] The question of availability "is partially dependent on 'lead time,' the time in which the technology will have to be available."[23] And since the standards under 111(d) apply to existing sources, rather than sources coming into existence at a future time, the lead time necessarily is short and must be considered when establishing BSER.

2. *The Emission Standard Based on the Chosen Technology Must Be Achievable*

Under the second element, which requires the standard of performance to be "achievable," EPA must show that the performance standard to be achieved through application of the BSER is "within the realm of the adequately demonstrated system's efficiency" and cannot be set "at a level that is purely theoretical or experimental."[24] Rather, EPA must "approach [the] task in a systematic manner that identifies relevant variables and ensures that they are taken account of in analyzing test data."[25]

Additionally, EPA must ensure that the achievability analysis is "representative" of the industry and must "affirmatively show that its standard reflects consideration of the range of relevant variables that may affect emissions in different plants."[26] This includes explaining how the standard is "capable of being met under most adverse circumstances which can reasonably be expected to recur."[27]

3. *Costs, Energy, and Environmental Impacts Must Be Considered*

Finally, in determining the BSER, EPA also must account for "the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements."[28]

Because it generally costs more to retrofit existing sources with pollution controls than to implement controls in new sources, EPA has recognized that "the degree of control reflected in EPA's emission guidelines will take into account the costs of retrofitting

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[21] *Essex*, 486 F.2d at 433–34 (quoting Portland Cement, 486 F.2d at 391).
[22] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999).
[23] *Id.*
[24] *Essex*, 486 F.2d at 433–34 (quoting *Portland Cement*, 486 F.2d at 391); *accord Lignite Energy Council*, 198 F.3d at 934.
[25] *Nat'l Lime Ass'n*, 627 F.2d at 443.
[26] *Id.* at 433.
[27] *Id.* at 431 n.46; *accord Sierra Club v. Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981) (EPA must "establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect achievability of the standard").
[28] 42 U.S.C. § 7411(a)(1); *accord Essex*, 486 F.2d at 433 (an adequate demonstration requires, among other things, showing that the system "can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way"); H.R. Rep. No. 95-294, at 190 (1977), as reprinted in 1977 U.S.C.C.A.N. 1077, 1269 ("[C]osts, energy, and environmental impacts [are] required to be considered in determining best technology which has been adequately demonstrated.").

existing facilities and thus will probably be less stringent than corresponding standards of performance for new standards."[29]

IV. EPA's Approach to BSER Exceeds its Authority Under the Clean Air Act

EPA has proposed federal standards of performance for new and modified sources as well as emissions guidelines for existing sources based on the same BSER determinations for different subcategories of fossil-fuel fired EGUs.

These aggressive BSER determinations exceed EPA's authority under the CAA because they do not account for differences between new and existing sources, they regulate sources in a manner that the major questions doctrine forbids, and they regulate "outside of the fence line" in contravention of the language of the Clean Air Act.

A. EPA Failed to Consider the Inherent Differences Between BSER for New and Existing Sources

"Although section 111(d) does not explicitly provide for variances, it does require consideration of the cost of applying standards to existing facilities. Such a consideration is inherently different than for new sources because controls cannot be included in the design of an existing facility and because physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases."[30] EPA did not adequately account for this inherent difference between new and existing sources and instead, concluded that BSER is the same for both.

B. The Proposed Rule Runs Afoul of the Major Questions Doctrine

The Proposed Rule's goal of forcing early retirements and shifting the nation's energy source from coal and natural gas to hydrogen once again runs afoul of the major questions doctrine as outlined in *West Virginia v. EPA*, 142 S. Ct. 2587, 2615 (2022).

In *West Virginia*, the issue before the Court was "whether restructuring the Nation's overall mix of electricity generation, to transition from 38% coal to 27% coal by 2030, can be the 'best system of emission reduction' within the meaning of Section 111."[31] The Court held that, while "[c]apping carbon dioxide emissions at a level that will force a nationwide transition away from the use of coal to generate electricity may be a sensible 'solution to the crisis of the day' . . . it is not plausible that Congress gave EPA the authority to adopt on its own such a regulatory scheme in Section 111(d)."[32] It reasoned, under the "major questions" doctrine, that "[a] decision of such magnitude and consequence rests with

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[29] 40 Fed. Reg. 53,340, 53,340 (Nov. 17, 1975); *see also id.* at 53,341 ("[T]he degrees of control represented by EPA's emission guidelines will ordinarily be less stringent than those required by standards of performance for new sources because the costs of controlling existing facilities will ordinarily be greater than those for control of new sources.").
[30]40 Fed. Reg. 53,340, at 53,344 (Nov. 17, 1975).

[31] *West Virginia,* 142 S. Ct. at 2595.
[32] *Id.* at 2616

Congress itself, or an agency acting pursuant to a clear delegation from that representative body."[33]

In other words, EPA's decision to employ generation shifting was a major question, requiring clear delegation from Congress, because forced generation shifting dictates "how much coal-based generation there should be over the coming decades."[34] Because the language of Section 111(d), setting forth EPA's obligation to determine the "best system of emission reduction," did not contain clear delegation to regulate the entire power grid as a "system," EPA's rule was invalid.[35]

The major questions doctrine, thus, is directly relevant to EPA's Proposed Rule as it imposes BSER on coal-fired and natural-gas fired EGUs. Under the requirements of the Proposed Rule, coal-fired EGUs will be forced to either retire or install experimental technology that is prohibitively expensive. The Proposed Rule provides a similar ultimatum to natural gas-fired EGUs—reduce power generation or completely switch to hydrogen fuel, a change that is dependent on non-existent technology and infrastructure. Under the major questions doctrine, EPA must be able to point to "clear congressional authorization" when it proposes such a rule of vast "economic and political significance."[36] "A decision of such magnitude and consequence on a matter of earnest and profound debate across the country must rest with Congress itself, or an agency acting pursuant to a clear delegation from that representative body."[37]

Courts have invoked the major questions doctrine numerous times both before and after the *West Virginia* decision. For example, a plurality of the Supreme Court found it "unreasonable to assume" Congress delegated "unprecedented power over American industry" without a "clear . . . mandate."[38] In 2021, the Supreme Court concluded that Congress did not authorize the Centers for Disease Control and Prevention to impose a nationwide eviction moratorium in response to the COVID-19 pandemic.[39] In 2023, the Supreme Court held that the Secretary of Education did not have authority to cancel student loan debts though the Secretary could "waive or modify" existing provisions applicable to financial assistance programs.[40]

The same reasoning the Court applied in *West Virginia* and other major questions doctrine jurisprudence also applies here. EPA's Proposed Rule is not intended to implement BSER, but rather to force the early retirement of coal-fired generation and to limit the capacity of natural gas-fired generation. Indeed, in direct contravention of *West*

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[33] *Id.*
[34] *Id.* at 2596.
[35] *Id.* at 2616.
[36] *Id.* at 2608–09.
[37] *Biden v. Nebraska*, 143 S. Ct. 2355, 2374 (2023) (internal citations omitted). The major questions doctrine responds to "the danger posed by the growing power of the administrative state." *City of Arlington v. FCC*, 569 U.S. 290, 315 (2013) (Roberts, C.J., dissenting.).
[38] *Indus. Union Dept., AFL-CIO v. Am. Petroleum Inst.*, 448 U.S. 607, 645–46 (1980) (plurality).
[39] *See Alabama Ass'n of Realtors v. Dep't of Health & Hum. Services*, 141 S. Ct. 2485, 2486 (2021).
[40] *Biden v. Nebraska*, 143 S. Ct. 2355, 2375 (2023).

Virginia, the Proposed Rule specifies "how much coal-based generation there should be over the coming decades."[41]

As the Regulatory Impact Analysis makes clear, most affected units will either retire or limit capacity rather than adopt the BSER. EPA's own analysis predicts that "[b]y 2030 the proposal is projected to result in an additional 1 GW of coal retirements, by 2035 an incremental 23 GW of coal retirements and by 2040 an incremental 18 GW of coal retirements relative to the baseline."[42] For existing fossil fuel-fired combustion turbines, EPA estimates that most base load units will simply reduce capacity rather than install CCS or co-fire hydrogen.[43] Indeed, EPA modeling predicts that none of the of the 494 GW of natural gas operating in 2035 will pursue hydrogen and instead will simply reduce their capacity factor to 50%.[44] As EPA attempted to do in *West Virginia*, this Proposed Rule engages in generation shifting to dictate how much of our nation's energy can be generated by coal and natural gas. This scheme violates the major questions doctrine.

C. EPA's Proposed Rule Exceeds Its Authority by Regulating Beyond the "Fence Line"

The text of CAA Section 111 demonstrates that Congress intended that regulation of stationary sources under that section is limited to regulation "inside the fence line." The use of "source" in this section demonstrates that the "standard of performance" applies to what any one *source* can accomplish. In contrast, regulating "outside the fence line" occurs when EPA sets standards to reduce emissions that cannot be achieved within the limits of the source itself, and instead rely on actions by third parties.

Although the Supreme Court in *West Virginia v. EPA* saw "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," it expressed skepticism that outside the fence line regulation is permissible under the Clean Air Act.[45] Tellingly, the Court observed that "EPA has acted consistent with such a limitation for the first four decades of the statute's existence."[46]

Despite the Supreme Court's warning in *West Virginia,* EPA once again exceeds its authority under Section 111 by regulating outside the fence line. Here, EPA asserts that the Proposed Rule properly focuses on individual sources and that "systems of emissions reduction like fuel switching, add-on controls, and efficiency improvements fall comfortably within the scope of prior practice as recognized by the Supreme Court."[47] But EPA's chosen technologies (CCS and co-firing low-GHG hydrogen) cannot generally be

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[41] *See West Virginia*, 142 S. Ct. at 2596.
[42] U.S. EPA, REGULATORY IMPACT ANALYSIS 3-25 (May 2023), EPA-HQ-OAR-2023-0072-0007 [hereinafter "RIA"].
[43] RIA at 8-8 to -9 ("Of these 36.8 GW, 8.6 GW to 17.3 GW were identified as more likely to install CCS ...The remaining identified existing NGCC capacity was assumed to operate at 50 percent capacity factor.").
[44] *See* worksheet Table 1-16_US of SSR file ("Combine Cycle with CF Limit").
[45] *See* 142 S. Ct. at 2615.
[46] *Id.*
[47] 88 Fed. Reg. a 33,272.

operated within the fence line without the large-scale development of technology and infrastructure offsite. In almost all cases, affected facilities required to install CCS will not be able sequester captured CO_2 onsite. In these circumstances, the sources will need to rely on an extensive—but not yet existent—offsite system of infrastructure to transport the captured CO_2 and sequester it in suitable sites.

Similarly, natural gas-fired plants required to co-fire low-GHG hydrogen rely on established contracts with suppliers and existing pipelines—but an obligation to change entirely the fuel that is being combusted relies on third-party actions outside EGU owners' control. Operators of EGUs cannot reasonably be expected to produce low-GHG hydrogen onsite, but to comply with the requirement to co-fire low-GHG hydrogen in the Proposed Rule, a vast network of hydrogen production, storage, and transportation pipelines that are not currently in existence must be developed outside the affected facilities. These requirements are violative of the Clean Air Act, which requires a standard of performance to be set such that an individual source could comply based on technology or add-on controls that could be installed at the source.

V. CCS IS NOT BSER FOR EXISTING FOSSIL FUEL-FIRED STEAM GENERATING EGUS

Contrary to EPA's assertions, CCS is not BSER for existing fossil-fuel fired steam generating EGUs. EPA's Proposed Rule would require existing coal-fired steam generating EGUs that plan to retire after 2040 to install CCS by 2030 and capture 90% of carbon emissions from all of the flue gases at the stack.[48] EPA's Proposed Rule is unreasonable and should not be finalized.

First, CCS is not adequately demonstrated and thus cannot support achievable emission standards. The technology remains in its infancy and has not been demonstrated at scale. Most importantly, *no large power plants with multiple coal-fired steam generating EGUs have demonstrated sustained 90 percent capture of all CO_2 emissions from the stack*. EPA's Proposed Rule relies entirely on unsupported results from a single small demonstration project with a history of operational issues to impose an impossibly stringent standard vastly beyond what has been demonstrated. In addition, the expansive infrastructure needed to transport and store the captured carbon remains undeveloped and cannot be completed before 2030. Indeed, Basin Electric's own experience shows CCS remains infeasible at commercial scale.

Second, EPA's cost estimates are unreasonable. Even with tax incentives, CCS remains prohibitively expensive and EPA's Proposed Rule improperly relies on speculative developments to drive down cost. CCS will require affected facilities to spend billions of dollars to retrofit their existing EGUs with CCS with no guarantee that the new capture systems will be able to comply with the proposed standard.

Third, EPA's proposed timeline of 2030 is unreasonable and cannot be met. CCS technology on coal-fired plants has not been adequately demonstrated and EPA cannot

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[48] *Id.* at 33,346.

expect facilities to design, permit, and construct capture systems that are way beyond the current scale and performance of the technology, all within five years.

Finally, Basin Electric's own experience show the installation of CCS on coal-fired EGUs remains infeasible. Basin Electric has engaged in various efforts to advance CCS, including feasibility studies at its Antelope Valley and Dry Fork plants. Basin Electric conclusions from these studies remains the same—CCS is too expensive, will increase electricity costs, and requires too great of a parasitic load.

A. CCS is Not Adequately Demonstrated and Cannot Support Achievable Emission Standards

1. <u>*CO_2 Capture Technology is Not Adequately Demonstrated*</u>

90% capture of CO_2 emissions from existing large-scale coal-fired EGUs has not been adequately demonstrated. EPA's BSER for existing coal-fired steam generating units relies entirely on a single, small demonstration project at Unit 3 (110 MW) of the Boundary Dam facility in Canada to justify the capture component of CCS.[49] As a matter of first principles, a BSER cannot and should not be based on a single example, especially one that does not satisfy the standard being proposed. Additionally, the Boundary Dam project has been enormously expensive, encountering operational problems that result in parasitic load, leaving the project unable to achieve its designed capture rate. EPA stretches the concept of BSER well beyond its established limits.[50] Furthermore, the Boundary Dam project was heavily subsidized by—and would not have been possible without the funding of—the Canadian federal and provincial governments. As detailed below, EPA's Proposed Rule fails to demonstrate that 90% capture is BSER.

Most notably, EPA provides little to no proof to support its emissions standard of 90% capture at coal-fired steam generating units.[51] EPA's entire proposal is premised on the Boundary Dam's demonstration of 90% capture. Yet EPA's Proposed Rule provides no proof or hard data, relying instead on two sources that provide no such authority: an article[52] on the difficulties encountered by Boundary Dam during start up and a recent blog post[53] by Boundary Dam showing 90% availability of the system in the 2nd and 3rd quarter of 2022—not capture efficiency.[54] Neither source supports a standard based on 90%

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[49] *Id.* at 33,346.
[50] *See Essex,* 486 F.2d at 433 (BSER "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.").
[51] 88 Fed. Reg. at 33,346.
[52] Giannaris, S., et al. Proceedings of the 15th International Conference on Greenhouse Gas. Control Technologies (March 15–18, 2021), SaskPower's Boundary Dam Unit 3 Carbon Capture Facility–The Journey to Achieving Reliability, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820191 (submitted as "Attachment 1 – SaskPower's Boundary Dam Unit 3 Carbon Capture Facility").
[53] *BD3 Status Update: Q3 2022*, SASKPOWER.com (October 18, 2022), https://www.saskpower.com/about-us/our-company/blog/2022/bd3-status-update-q3-2022 (showing 94.5% availability in Q32022).
[54] *See* 88 Fed. Reg. at 33,254 (citing article), 33,292 n. 247 (citing blog post).

capture of *all carbon emissions*. EPA's technical support document entitled *Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document* is similarly lacking in citations or record support.[55] EPA cannot set a standard for all affected facilities based on such a dearth of evidentiary support.

Even if the scant evidence that EPA provides is considered, EPA has not demonstrated that a 90% capture rate has been adequately demonstrated. In order to be achievable, EPA must show that the performance standard is "within the realm of the adequately demonstrated system's efficiency" and cannot be set "at a level that is purely theoretical or experimental."[56] Based on published information, Boundary Dam has only met its design capacity briefly. Although Boundary Dam was designed to capture 90% of carbon emissions from all the flue gas at the unit, "for both technical reasons and to minimize the cost of electricity and maximize electrical output, it has not sustained the design rate beyond a dedicated capacity demonstration completed in 2015."[57] This fact alone demonstrates that the technology has not been adequately demonstrated and is not achievable.

EPA's Proposed Rule also does not account for the fact that neither Boundary Dam nor Petra Nova diverts all of their flue gases to the carbon capture systems. In setting standards of performance, EPA must "approach [the] task in a systematic manner that identifies relevant variables and ensures that they are taken account of in analyzing test data."[58] Additionally, EPA (or the state) must ensure that the achievability analysis is "representative" of the industry and must "affirmatively show that its standard reflects consideration of the range of relevant variables that may affect emissions in different plants."[59] EPA's analysis fails to meet this standard. Nowhere in the Proposed Rule does EPA consider the fact that although the CCS facility on Unit 3 of Boundary Dam "has nameplate capacity to capture 90 per cent of the CO_2 from all the flue gas generated by the Unit 3 turbine (an estimated 1 million tonnes of CO_2 per year), the CCS facility has *operated at an average of 60-65 per cent of its design capacity over the last eight years, which equates to roughly 50 per cent of all CO_2 emissions generated by BD3*."[60] Relatedly, when the facility has achieved 90% capture it was operating at 70% to 80% of its design capacity.[61]

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[55] U.S. EPA, GREENHOUSE GAS MITIGATION MEASURES FOR STEAM GENERATING UNITS TECHNICAL SUPPORT DOCUMENT (May 2023) (EPA-HQ-OAR-2023-0072-0061).
[56] *Essex*, 486 F.2d at 433–34 (quoting Portland Cement, 486 F.2d at 391).
[57] Jacobs, Brent and Tantikhajorngosol, Puttipong and Hill, Keith and Ruffini, Jonathan and Wilkes, Sarah and Srisang, Wayuta and Feng, Yuewu and Daverne, Doug and Nelson, Conway, Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities (October 24, 2022); Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT-16) 23-24 Oct 2022, available at SSRN: https://ssrn.com/abstract=4286430 or http://dx.doi.org/10.2139/ssrn.4286430 (submitted as "Attachment 2 – Reducing the CO2 Emission Intensity of Boundary Dam Unit 3").
[58] *Nat'l Lime Ass'n*, 627 F.2d at 443.
[59] *Id.* at 433.
[60] *Carbon Capture on BD3 – Successful by Design*, CCSKNOWLEDGE.COM (May 12, 2023) https://ccsknowledge.com/blog/carbon-capture-on-bd3---successful-by-design (emphasis added).
[61] Jacobs et. al., *supra* note 55; Proceedings of the 16th Greenhouse Gas Control Technologies Conference, *supra* note 55 (""The results show that the CCP when operating at 70% to 80% of the designed capture capacity achieved over 90% CO_2 capture efficiency in 2021.").

Similarly, EPA's analysis fails to identify and account for other important variables, such as the number and size of the EGUs, that may influence the achievability analysis.

Similarly, the Petra Nova project in Texas only captured a small portion of the emissions from a single EGU before it shut down in 2020.[62] Petra Nova's 240-megawatt ("MW") carbon capture system was added to Unit 8 (654 MW capacity) of the existing W.A. Parish coal-fired power plant.[63] The carbon capture system received about 37% of Unit 8's emissions, which were diverted through a flue gas slipstream.[64] Because Petra Nova's carbon-capture system was designed to capture about 90% of the CO_2 emitted from the flue gas slipstream, the system only captured a maximum of 33% of the total emissions from Unit 8.[65] Even though Petra Nova relied on extensive financial assistance from the federal government, the carbon capture system was shut down in 2020 due to financial issues.[66] Although plans have been announced to restart the system, to date the system has not restarted operations.

EPA's reliance on the Petra Nova project additionally violates the express statutory prohibition on considering such projects subsidized by the DOE's Clean Coal Power Initiative when making a BSER determination under CAA Section 111.[67] This prohibition is based on the sound policy that a technology cannot be adequately demonstrated if it requires extensive subsidies to be implemented. EPA claims that it relies on such projects only to provide "additional information" to support the BSER determination.[68] However, EPA relies on the Petra Nova project as a bedrock example of CCS. Without it, EPA has very little support for its determination.

EPA attempts to bolster its BSER determination for coal-fired EGUs with examples of partial capture at other coal-fired plants (10% capture at 180–MW Warrior Run plant and 5% capture at 320-MW Shady Point plant) and different industrial processes (syngas at Quest CO_2 capture facility).[69] Simply put, capture in such miniscule amount at other coal-fired plants and at other industrial processes (such as syngas or ethanol with different flue gas streams dense in CO_2) does not demonstrate that 90% capture at coal-fired steam generating units is adequately demonstrated. In fact, EPA's reliance on these examples shows the very lack of support for its own proposed emissions standard. Finally, EPA claims that higher capture percentages may be achievable based on a 2018 feasibility study for the Shand Power Station, which indicated that the proposed carbon capture could

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[62] U.S. DOE, W.A. PARISH POST-COMBUSTION CO_2 CAPTURE AND SEQUESTRATION DEMONSTRATION PROJECT, FINAL SCIENTIFIC/TECHNICAL REPORT (March 31 2020), https:// www.osti.gov/servlets/purl/1608572.
[63] *Id.*
[64] *Id.*
[65] *Id.*
[66] *Id.*
[67] 42 U.S.C. § 15962(i) ("No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be. . . adequately demonstrated for purposes of section 111 of the Clean Air Act.").
[68] 88 Fed. Reg. at 33,291.
[69] 88 Fed. Reg. at 33,292, 33,346

achieve capture rates of 97%.[70] EPA's reliance on this study is also unpersuasive since the project was never developed and the capture rates have never been proven.

2. *CO_2 Transportation is Not Adequately Demonstrated*

Transportation pipelines linking sources of captured carbon to disposal sites is a critical component of CCS. For a variety of reasons, such as geology, facilities will not be able to dispose of captured carbon on site. In order to make carbon capture work, facilities must be able to safely and efficiently transport the CO_2 captured at their facilities to an offsite storage site, potentially hundreds of miles away. Because a nationwide network of CO_2 pipelines does not yet exist in the United States, EPA's Proposed Rule relies on the future availability and development of a vast CO_2 pipeline network. Since EPA's BSER determination relies on projections of the future availability of technology, it cannot be based on a "subjective understanding of the problem or a 'crystal ball inquiry.'"[71] Here, EPA fails to prove that the CO_2 transportation network critical to CCS is adequately demonstrated.

While several regional CO_2 pipeline networks currently exist or are being developed, the United States currently lacks the vast national pipeline infrastructure needed to implement the rule. As of 2021, only 5,339 miles of CO_2 pipeline are in operation.[72] In comparison, the nation's natural gas pipeline network is over 3 million miles long.[73] In order to facilitate the widespread deployment of carbon capture, the United States will need to significantly expand its pipeline and storage capacity at an unprecedented rate. According to some estimates, the United States will need upwards of 65,000 miles of CO_2 pipelines at a capital cost of $170 to $230 billion.[74]

EPA's Proposed Rule vastly underestimates the scale of the build out necessary to implement the rule and the challenges likely to be encountered.[75] To justify the rule, EPA relies on the distance to potential saline sequestration sites rather than existing storage sites,[76] as well as speculative developments from new or expanded pipeline.[77] Yet EPA's Technical Support Document, *Greenhouse Gas Mitigation Measures for Steam Generating Units*, cites planned pipelines as increasing the total potential CO_2 network to only 9,234

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[70] 88 Fed. Reg. at 33,291.
[71] *Essex*, 486 F.2d at 433–34 (quoting Portland Cement, 486 F.2d at 391); *accord Lignite Energy Council*, 198 F.3d at 934 ("EPA may not base its determination . . . on mere speculation or conjecture . . . .").
[72] 88 Fed. Reg. at 33,294.
[73] 88 Fed. Reg. at 33,352.
[74] PRINCETON UNIVERSITY, NET-ZERO AMERICA: POTENTIAL PATHWAYS, INFRASTRUCTURE, AND IMPACTS, FINAL SUMMARY REPORT (October 29, 2021) (submitted as "Attachment 3 – Excerpt from Princeton University_Net-Zero America Report").
[75] 88 Fed. Reg. at 33,369 ("Other analyses indicate that the size of CO_2 pipeline network necessary to capture over 1,000 million metric tons per year of CO_2 emissions from large, frequently operated coal and natural gas EGUs ranges from 20,000 miles to 25,000 miles.").
[76] 88 Fed. Reg. at 33,347 ("77 percent of existing coal-fired steam generating units that have planned operation during or after 2030 are within 80 km (50 miles) of potential saline sequestration sites, and another 5 percent are within 100 km (62 miles) of potential sequestration sites.")
[77] 88 Fed. Reg. at 33,294.

miles.[78] This is far short of the 65,000 miles needed to facilitate wide-spread adoption of CCS at coal-fired power plants. It is not even half of EPA's own underestimation of 20,000 miles of additional pipelines. Even assuming that those planned pipelines are constructed and that additional CO_2 pipelines can be constructed at the average historic buildout of 2,000 miles per year for natural gas transmission pipelines,[79] the buildout necessary to meet EPA's low estimate of 20,000-25,000 miles would take another 10-15 years. Because EPA's determination relies on "mere speculation" that the vast transportation network necessary to support CCS can be developed by 2030, EPA has not demonstrated that CCS is adequately demonstrated.

3. Geologic Sequestration is Not Adequately Demonstrated

EPA's Proposed Rule also fails to demonstrate that geologic sequestration is adequately demonstrated. For CCS to be successful, facilities must be able to safely and securely dispose of the CO_2 captured. Because EPA's Proposed Rule relies on the future widespread availability of adequate storage sites and does not demonstrate that they can be developed before 2030, EPA has not demonstrated that CCS is adequately demonstrated.

While the United States possesses geology in several states with significant potential for geologic sequestration, there are few existing sequestration sites and no large commercial-scale storage facilities. Even though EPA has authority to permit geologic sequestration under the Safe Drinking Water Act's Underground Control Program through a Class VI permit, EPA has to date only issued two Class VI permits in Illinois while dozens remain pending.[80] EPA cannot claim that geologic sequestration is readily demonstrated based on these two sites alone. For this reason, EPA relies on the availability of potential saline sequestration sites rather than existing sites. EPA however provides no proof that the buildout of geologic sequestration sites at the scale necessary to implement the rule can be achieved by the deadline provided. Finally, EPA's Proposed Rule does not account for the fact that many, if not most states, lack the geology as well as the legal or regulatory schemes related to pore space and carbon storage necessary to facilitate large carbon storage projects. Without these legal standards in place, companies cannot move forward with sequestration projects.

Because EPA's BSER determination relies on "mere speculation" that a sufficient number and capacity of geologic sequestration sites can be developed to store captured CO_2 by 2030, EPA has not established that CCS is adequately demonstrated.

B. CCS Cost Estimates Are Unreasonable

Installation of CCS is currently cost-prohibitive and EPA's cost estimates for installing CCS are not reasonable. EPA predicts $8 per ton of CO_2 reduced and $7 per

[78] U.S. EPA, GREENHOUSE GAS MITIGATION MEASURES FOR STEAM GENERATING UNITS TECHNICAL SUPPORT DOCUMENT (May 2023) (EPA-HQ-OAR-2023-0072-0061).
[79] 88 Fed. Reg. at 33,369.
[80] *Class VI Wells Permitted by EPA*, EPA.GOV (August 3, 2023), https://www.epa.gov/uic/class-vi-wells-permitted-epa.

MW/H assuming 12-year amortization and a 50% annual capacity factor. These cost estimates are unreasonable given that the cost for installing existing CCS projects have exceeded over a billion dollars and were heavily subsidized by governments. For instance, Petra Nova is estimated to have cost over 1 billion dollars, while NRG received $195 million in DOE grants.[81] EPA's predictions for a significant decrease in cost relies heavily on future developments and proposed projects that have not been built. Specifically, EPA improperly relies on unidentified technological advances and funding from recently passed legislation.[82] Contrary to EPA's assertions, Basin Electric's recent cost estimate from a FEED study conducted at its Dry Fork Station showed that costs remain prohibitively expensive and a significant impediment to the adoption of CCS.[83] For Basin Electric, implementing CCS technology would require massive capital and operating costs and would negatively impact its ability to provide affordable electricity service to its members.

C. EPA's Proposed Timeline of 2030 is Unrealistic

EPA's proposed time of 2030 is also unrealistic and cannot be achieved by existing coal-fired EGUs. EPA's Proposed Rule would require all long-term existing coal-fired EGUs to capture 90% of carbon emissions by 2030 based on an estimated five-year timeline and the unsupported assertion that 9 GW of coal-fired steam generating units would apply CCS by 2030.[84]

As mentioned previously, CCS is not adequately demonstrated for existing coal-fired EGUs. For this reason alone, facilities cannot be expected to construct and install a technology that is not BSER. Boundary Dam has not shown 90% capture beyond a demonstration test and has operated well below its design capacity due to technological issues and economic reasons. EPA's proposal goes beyond what has been demonstrated and will require facilities to design and construct capture systems much larger and more efficient than Boundary Dam. While the Boundary Dam project was designed for only a single 110-MW unit, Basin Electric will need to install CCS on 8 coal-fired units totaling 2,817 MWs of generation, the smallest of which is twice the size of the Boundary Dam project.

Additionally, EPA's proposed five-year timeline wildly underestimates the time necessary to design, permit, and construct carbon capture systems. CCS is not an off-the-shelf technology, and each system will need to be custom designed to address the unique aspects of each facility. EPA's proposed timeline also does not consider the difficulties, such

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[81] 88 Fed. Reg. at 33,293, note 259 (citing DOE/NETL Final Technical Report: W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020)) https://www.osti.gov/servlets/purl/1608572.

[82] 88 Fed. Reg. at 33,245 ("The EPA recognizes that, since it promulgated the ACE Rule, the costs of CCS have decreased due to technology advancements as well as new policies including the expansion of the Internal Revenue Code section 45Q tax credit for CCS in the Inflation Reduction Act (IRA).")

[83] Membrane Technology and Research, Inc., Commercial-Scale Front-End Engineering Design (Feed) Study for MTR's Membrane CO_2 Capture Process, *available at* https://doi.org/10.2172/1897679 (submitted as "Attachment 4 – Excerpt from MTR FEED Study").

[84] 88 Fed. Reg. at 33,346, 33,372.

as supply chain constraints and skilled labor shortages, which will be encountered by all affected facilities attempting to build CCS at simultaneously.

EPA's timeline also does not properly account for the fact that facilities may encounter unexpected issues as they attempt to optimize and validate their systems. The immense number of difficulties that Boundary Dam has encountered presents a cautionary for any deadline that does not provide sufficient time for testing, validation, and optimization. Similarly, Petra Nova took over three years following construction to achieve its target percentage of 85% of a partial slipstream.[85] Among the unexpected challenges were facility forced outages, CO_2 pipeline shut-ins; the ability of the EOR project to receive captured CO_2, weather, planned maintenance, and partial day outages resulting from operational issues.[86] Despite these examples of multi-year struggles to achieve target capture rates, EPA unreasonably predicts that start-up, commissioning, and testing can be completed in only 26 weeks.[87]

EPA's timeline also does not fully consider the challenges related to transportation and carbon storage. Although EPA acknowledges that "building the infrastructure required to support wider use of CCS and qualified low-GHG hydrogen in the power sector will take place of a multi-year time scale," EPA assumes this can all be done in less than five years.[88] As mentioned earlier, EPA's own data show that the timeline necessary to buildout a minimal pipeline network on 20,000-25,000 miles will take well beyond 2030. EPA also fails to account for the growing opposition to the construction of new pipelines, particularly for new CO_2 pipelines in Midwest.[89] As the Keystone XL and Mountain Valley pipelines demonstrate protests and legal challenges can indefinitely delay and stop any pipeline project. Pipelines required to cross federal lands, will be required to secure additional permitting, including the analysis of the environmental impacts under the National Environmental Policy Act.

Further, EPA willfully ignores its own failure to timely issue Class VI disposal permits. To date, EPA has only issued two Class VI permits while dozens remain pending.[90] Although EPA took an average of six years to issue both permits and has not issued a new Class VI permit since 2021,[91] EPA predicts that the site characterization and permitting for

[85] U.S. DOE, W.A. PARISH POST-COMBUSTION CO_2 CAPTURE AND SEQUESTRATION DEMONSTRATION PROJECT, FINAL SCIENTIFIC/TECHNICAL REPORT (March 31 2020), https://www.osti.gov/servlets/purl/1608572 ("Petra Nova has demonstrated that the facility can operate and maintain the targeted CO_2 capture rate of 5,200 short tons per day during all ambient conditions but underestimated the assortment of system challenges with achieving an annual capacity factor of 85%.").
[86] *Id.*
[87] U.S. EPA, GREENHOUSE GAS MITIGATION MEASURES FOR STEAM GENERATING UNITS TECHNICAL SUPPORT DOCUMENT (May 2023) (EPA-HQ-OAR-2023-0072-0061).
[88] 88 Fed. Reg. at 33,244
[89] Jonathan Weisman, *A Left-Right Alliance Puts Iowa's CO_2 Pipelines on the Presidential Agenda*, New York Times (July 30, 2023), https://www.nytimes.com/2023/07/30/us/politics/iowa-pipelines-trump.html.
[90] *Class VI Wells Permitted by EPA*, EPA.GOV (August 3, 2023), https://www.epa.gov/uic/class-vi-wells-permitted-epa.
[91] *Id.*

both transportation and storage can be completed in two years.[92] This timeline is patently unreasonable, given the existing backlog as well as the additional applications that will be filed as a result of this rule.

D. Basin Electric's Own Experience Shows CCS is Currently Technically and Economically Infeasible

Basin Electric has engaged in extensive efforts to participate in CCS research and development, including spending millions of dollars toward project development to build a demonstration project at Antelope Valley Station that would capture 90% of CO_2 emissions from approximately 120 MW gross, or 25% of one of the units at the plant. Even with a $100 million grant from the Department of Energy ("DOE") and the availability of Dakota Gasification Company's pipeline for transporting the captured CO_2, Basin Electric's feasibility study determined that the technology required too great a parasitic load, came with an estimated cost of at least $500 million, and would result in a significant increase in the cost of electricity to its members.

More recently, an evaluation was done on the feasibility of installing CCS (membrane-based post-combustion capture technology with 70% capture) at Basin Electric's Dry Fork Station.[93] This evaluation reinforced the same conclusion as the earlier feasibility study for Antelope Valley Station. Specifically, installing CCS would be prohibitively expensive—with total project capital costs for the capture system alone exceeding 1.5 billion dollars—with too great of a parasitic load and a significant increase in the cost of electricity. In fact, the capital costs for installation of the capture system alone would exceed the costs (approximately 1.35 billion) to actually construct the Dry Fork Station which began operations just twelve years ago.[94] Currently, an additional study is being conducted to evaluate if the technology can even reach 90% capture along with the additional costs associated with it. Since Basin Electric continues to experience load growth, it cannot afford to divert 25-30% of its power generation to CCS nor can it reasonably build out new generation to make up for that lost supply. EPA's Proposed Rule would force companies to install this prohibitively expensive technology with a significant reduction in generation capabilities.

VI. CCS and Low-GHG Hydrogen Co-Firing are not BSER for Existing Fossil Fuel-Fired Stationary Combustion Turbine EGUs

In the Proposed Rule, EPA determined that CCS and hydrogen co-firing are BSER for existing stationary combustion turbines with a capacity greater than 300 MW and a

[92] U.S. EPA, Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document (May 2023) (EPA-HQ-OAR-2023-0072-0061).

[93] Membrane Technology and Research, Inc., Commercial-Scale Front-End Engineering Design (Feed) Study for MTR's Membrane CO_2 Capture Process, *available at* https://doi.org/10.2172/1897679 (submitted as "Attachment 4 – Excerpt from MTR FEED Study").

[94] *Dry Fork Station*, basinelectric.com (last visited August 2, 2023), https://www.basinelectric.com/about-us/Generation/index?location=dryforkstation.

capacity factor greater than 50%.[95] EPA based these determinations on insufficient evidence and unreasonable projections that amount to "mere speculation." Accordingly, CCS and hydrogen co-firing are not adequately demonstrated and are not BSER.

A. CCS on Existing Combustion Turbines is Not Adequately Demonstrated and Cannot Support Achievable Emission Standards

The Proposed Rule fails to demonstrate that 90% capture of CO_2 at combustion turbines has been adequately demonstrated. Because no existing combustion turbines have installed CCS demonstrating 90% capture, EPA relies on a single demonstration project at a steam generating unit (Boundary Dam) to justify CO_2 capture at combustion turbines.[96] As explained in Section VI.A. of this comment letter, Boundary Dam has been plagued by technical issues and unable to attain its design rate beyond a single dedicated capacity demonstration completed in 2015.[97]

In addition, EPA's Proposed Rule dismisses the significant differences between steam generating units and combustion turbines that impact the suitability of CCS. Specifically, the flue gas from natural gas-fired EGUs have a higher oxygen content and a lower CO_2 concentration than at a coal-fired EGU. These unique attributes make CCS at natural gas-powered combustion turbines not only more technologically challenging but more expensive.

EPA attempts to bolster its BSER determination for combustion turbines with the shuttered capture system at the Bellingham Energy Center, which only captured a 40MW slipstream from a combined cycle EGU from 1991 to 2005. This small demonstration project does not provide evidence that capture technology for combustion turbines has been adequately demonstrated at full-scale, especially given the issues with capturing the CO_2 stream from a natural gas-powered combustion turbine that make it more expensive and technologically challenging.

Finally, EPA relies on the same unsupported justification for transportation and geologic sequestration for fossil fuel-fired steam generating units to support its BSER for combustion turbines.[98] As discussed in Sections V.A.2 and V.A.3 of Basin Electric's comments, the United States currently lacks the vast national pipeline infrastructure and existing sequestration sites needed to implement the rule. EPA's Proposed Rule underestimates the scale of development needed to implement the rule as well as the costs and timelines. For these reasons, CCS has not been adequately demonstrated nor is the proposed emissions standard achievable.

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[95] 88 Fed. Reg. at 33,362.
[96] 88 Fed. Reg. at 33,367–68.
[97] Jacobs et. al., *supra* note 55; Proceedings of the 16th Greenhouse Gas Control Technologies Conference, *supra* note 55.
[98] 88 Fed. Reg. at 33,368.

B. Low-GHG Hydrogen Co-Firing is Not Adequately Demonstrated and Cannot Support Achievable Emission Standards

Widespread co-firing of low-GHG hydrogen at base load stationary combustion turbines is a novel concept that is only theoretically possible. To become commercially available will require significant technological advances, massive infrastructure investment across the entire power sector, and the creation of an entirely new industry to produce low-GHG hydrogen at large scale. Because of the current complexity and scale of these challenges, predicting when hydrogen co-firing will be feasible to implement at existing stationary combustion turbines is the very type of "crystal ball inquiry" that cannot support a BSER determination.[99]

Nonetheless, EPA proposes to determine that co-firing 30% low-GHG hydrogen by volume by 2032 and 96% by 2038 is BSER for existing baseload stationary combustion turbines over 300 MW with a capacity factor of greater than 50%.[100] EPA's justification for this BSER determination is insufficient for four reasons:

1. EPA's projection that the technology to co-fire hydrogen at high percentages is unreasonable because it relies on the speculative goals of new power projects and manufacturers rather than a technical analysis of the challenges that must be overcome;

2. EPA's projection that the infrastructure necessary to support hydrogen co-firing will be available by the implementation dates is unreasonable because it relies on the speculative impacts of new federal funding programs and the requirements of the Proposed Rule itself;

3. The BSER determination fails to meet the standard for justifying a "technology-forcing" regulation; and

4. EPA's cost estimate is unreasonable.

EPA's projections for the necessary technological advances, infrastructure developments, and cost are unreasonable and amount to "mere speculation." Therefore, low-GHG hydrogen co-firing is not adequately demonstrated and cannot support achievable emission standards.

1. *<u>EPA's Technology Projections for Co-firing Hydrogen at High Percentages are Unreasonable and Rely on Speculative Goals</u>*

The technology to co-fire above 30% hydrogen in stationary combustion turbines that support baseload generation does not currently exist. Manufacturers have explained to Basin Electric that only up to 30% hydrogen co-firing is currently possible.

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[99] *Portland Cement Ass'n*, 486 F.2d at 391.

[100] 88 Fed. Reg. at 33,245–46.

Achieving hydrogen co-firing at higher percentages in baseload turbines poses significant engineering challenges that manufacturers have yet to overcome. As the Proposed Rule acknowledges, the physical characteristics of hydrogen create serious issues concerning flame temperature, flame speed, flammability range, flashback, and heightened wear on the components within such large turbines.[101] Manufacturers must resolve these complex technical problems before co-firing above 30% will be technically feasible—much less commercially viable.

Additionally, retrofitting an existing natural gas facility with hydrogen co-firing technology poses its own engineering challenges, even at 30% co-firing. When combusted, hydrogen is less than one-third as energy efficient as the methane that natural gas facilities currently burn. Accordingly, more than three times the volume of fuel gas is needed to replace methane with hydrogen. Together with the characteristics of hydrogen, the increased volume of fuel gas would require re-sizing of fuel lines throughout Basin Electric's facilities as well as new systems to ensure higher tightening of lines to prevent leaks. Further, new safety systems, equipment, and protocols must be developed to support such retrofits. Based on the current state of the technology, projecting when the technology will sufficiently advance to support greater percentages of 30% co-firing is highly speculative and cannot meet the level of precision necessary to justify the aggressive requirements of the Proposed Rule.

EPA claims that co-firing 30% hydrogen by 2032 and 96% hydrogen by 2038 is adequately demonstrated based on "announced plans of manufacturers and generators to undertake retrofit projects for hydrogen co-firing."[102] Basing the aggressive regulatory requirements of the Proposed Rule on the plans and goals of manufacturers and generators rather than an in-depth technical analysis of the development of the technology is unreasonable.

EPA references general statements by GE, Siemens, and Mitsubishi on their websites to support its statement "that their turbines can currently co-fire some amounts of hydrogen" and that "they have plans to expand those capabilities."[103] EPA further cites industry articles on GE and Siemens' goals of achieving high levels of hydrogen co-firing in base load turbines to support its claim that "the major turbine manufacturers are designing combustion turbines that will be capable of combusting 100 percent hydrogen by 2030."[104] However, these short articles only quote general statements by the manufacturers regarding their "ambitious" plans and goals to achieve 100% hydrogen combustion.[105] These statements are simply that—speculative plans and goals by manufacturers who benefit from marketing their products as more innovative than their competitors'. These

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[101] 88 Fed. Reg. at 33,311.
[102] *Id.* at 33,363.
[103] *Id.* at 33,364.
[104] *Id.* at 33,312; *see also* Frederic Simon, *GE eyes 100% hydrogen fueled power plants by 2030* (May 12, 2021), https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/; Sonal Patel, *Siemens' Roadmap to 100% Hydrogen Gas Turbines* (July 1, 2020), https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/.
[105] *See id.*

statements do not provide technical analyses of the steps that manufacturers will take to achieve these plans and goals. Accordingly, they are not an appropriate basis for projecting when the necessary technology will be commercially available.

EPA also attempts to support its projections with examples of specific turbines that have fired higher levels of hydrogen.[106] EPA cites the development of the SGT-A35 turbine by Siemens Energy ("Siemens") and the B, E, and F class turbines by General Electric ("GE") as well as pilot projects of turbines in Fujiyoshida, Japan and Lingen, Germany to produce 320 kW and 34 MW of power, respectively.[107] However, these examples all concern smaller-scale turbines than what is required to produce power at Basin Electric's Deer Creek Station facility. As the complexity and production demands of base load turbines are orders of magnitude greater than the smaller turbines on which EPA relies, achieving higher levels of co-firing at base load turbines is a significant technological leap.

EPA relies on similarly speculative statements regarding newly announced utility projects with the goals of retrofitting turbines to co-fire high levels of hydrogen.[108] For example, EPA references the Long Ridge Energy Terminal that "is designed to enable a transition to 100 percent hydrogen fuel" but to date has only tested "5 percent hydrogen co-firing."[109] EPA also notes that Florida Power and Light "intends" to convert its existing turbine capacity to 100% hydrogen firing by 2045.[110] Additionally, EPA highlights a statement by Constellation Energy claiming that "retrofits using available technology can allow hydrogen blending at 50-100 percent by volume in select generators."[111] Constellation Energy does not identify these "select generators."[112] To the extent that EPA claims that such retrofits are available for existing base load turbines, such a statement contradicts the current assessment of the technology by manufacturers.

Further, EPA relies on the following general announcements for newly proposed projects:

- Los Angeles Department of Water and Power "foresees" that its proposed Scattergood Modernization project will run on 100% hydrogen by 2035;

- The Intermountain Power Agency's new plant currently in development is "projected. . . to transition to 100 percent hydrogen by 2045";

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[106] 88 Fed. Reg. at 33,308.
[107] *Id.*; *id.* at 33,308; U.S. EPA, HYDROGEN IN COMBUSTION TURBINE ELECTRIC GENERATING UNITS TECHNICAL SUPPORT DOCUMENT 10 (May 23, 2023) (Docket ID No. EPA-HQ-OAR-2023-0072).
[108] *See* 88 Fed. Reg. At 33,364.
[109] *Id.*
[110] *Id.*
[111] *Id.*
[112] *See* Constellation Energy Corporation's Comments on EPA Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric, at 5.

- Duke Energy Corporation has "outlined plans for full hydrogen capabilities" and has "assumed" that its natural gas plants built after 2030 will be convertible to full hydrogen;

- Cricket Valley Energy Center is retrofitting its plant "as a first step toward the conversion to a 100 percent hydrogen."[113]

Like the statements of manufacturers, these announcements by select power generators provide speculative goals, projections, and assumptions. They are not based on guarantees by manufacturers that the technology will be available to support high levels of hydrogen co-firing by the various target dates that they reference. Indeed, many of these announcements simply refer to the uncertain goals of the manufacturers to make the necessary technological innovations in time.[114]

It is unreasonable for EPA to base its projections of when this technology will be commercially available on the speculative plans of goals of manufacturers and certain power generators. EPA must base such projections on a detailed technical analysis that considers what manufacturers can feasibly accomplish, not what they aspire to achieve.

The closest that EPA comes to a technical analysis of the state of the technology is a single reference to a National Energy Technology Laboratory ("NETL") report from 2022, which concluded that "a fully commercialized, low-NOx, high-hydrogen turbine can be developed within the next 20 years with enough R&D."[115] Within that timeframe, the report states that "it is likely that a majority of the industry will have the capabilities to produce commercial-grade, 100% hydrogen engines by around 2030."[116]

Importantly, the NETL report emphasizes that "hydrogen's high flame temperature and flame speed remain key challenges that Siemens, GE, and all other manufacturers continue to face. . . ."[117] Other than generally referring to "current research progress and publicly announced forecasts," the NETL report does not support its projections with any explanation of how manufacturers will overcome these challenges.

EPA cannot rely on the plans and goals of manufacturers and select power generators to justify its projection that the technology to co-fire 30% and 96% hydrogen at base load turbines will be commercially available by 2032 and 2038, respectively, without the support of a sufficient technical analysis.

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[113] 88 Fed. Reg. at 33,255, 33,308.
[114] *See e.g.*, 88 Fed. Reg. at 33,255 (explaining that Constellation Energy's projections rely on the plans of manufacturers to develop 100% hydrogen co-firing technology).
[115] NATIONAL ENERGY TECHNOLOGY LABORATORY, A LITERATURE REVIEW OF HYDROGEN AND NATURAL GAS TURBINES: CURRENT STATE OF THE ART WITH REGARD TO PERFORMANCE AND NOX CONTROL (DOE/NETL–2022/3812) (August 12, 2022), https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf.
[116] *Id.*
[117] *Id.* at 5.

2. *EPA's Projection that the Infrastructure Necessary to Support Co-firing Will be Available is Unreasonable and Speculative*

Widespread co-firing of low-GHG hydrogen at existing stationary combustion turbines on the proposed timelines will require the development of new hydrogen infrastructure at an unprecedented scale and pace. Because combusting hydrogen is less than one third as energy efficient as the methane that natural gas turbines currently burn, low-GHG hydrogen production will have to more than triple the current production of natural gas. As EPA acknowledges in the Proposed Rule, limited quantities of hydrogen are currently being produced that meet the proposed definition of low-GHG hydrogen.[118] Accordingly, generating the hydrogen necessary for this near-complete shift in fuel will require the development of massive low-GHG hydrogen production operations across the United States.

Additionally, the infrastructure to store massive volumes of low-GHG hydrogen and transport it to existing turbines does not currently exist. Basin Electric's Deer Creek Station facility, like most other natural gas facilities, does not have the space onsite to accommodate the substantial amount of hydrogen that would be needed to support co-firing. Basin Electric and other operators will instead have to rely on hydrogen transported from regional hydrogen hubs or centralized storage facilities.

The current natural gas pipeline system could theoretically accommodate a mixture of up to approximately 30% of hydrogen. However, EPA acknowledges that transporting higher percentages of hydrogen poses significant "technical concerns" including the embrittlement of existing steel pipelines, tightening lines to prevent leaks, the inability to control hydrogen leaks when they occur, and the need for lower cost, more reliable, and more durable hydrogen compression technology.[119] Even if these technical challenges are overcome, mixing hydrogen into existing natural gas pipelines implicates a host of logistical issues for servicing other natural gas customers, such as individual American households, that will continue to be reliant on the current pipeline system but will not be co-firing hydrogen.

Ultimately, new pipelines dedicated to the transportation of hydrogen and methane mixtures will need to be constructed. As EPA notes, there are currently only "1,600 miles of dedicated hydrogen pipeline infrastructure."[120] In comparison, the current natural gas network comprises "about 3 million miles" of pipelines that link natural gas production and storage facilities with customers.[121] Developing this massive, integrated network took *decades* to complete and involved complicated siting, permitting, and construction issues. EPA also acknowledges that "the piping required to deliver pure hydrogen would have to be larger" and that "material used to construct the piping could need to be specifically

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118 88 Fed. Reg. at 33,312.
119 U.S. EPA, HYDROGEN IN COMBUSTION TURBINE ELECTRIC GENERATING UNITS, TECHNICAL SUPPORT DOCUMENT (EPA-HQ-OAR-2023-0072-0059) 26 (May 23, 2023).
120 88 Fed. Reg. at 33,308.
121 *Id.* at 33,352.

designed to be able to handle" the higher volume of hydrogen needed.[122] This would require the development of new materials, safety systems, and best practices, to say nothing of the massive challenge of permitting and construction of such new pipelines at a nationwide scale.

Sufficient hydrogen infrastructure must also provide opportunities for backup sources of low-GHG hydrogen. The Deer Creek Station facility currently draws natural gas from an interconnected network of natural gas producers and storage facilities. Relying on a network rather than a single source of fuel provides stability in the event that one or several sources become unavailable. However, converting to hydrogen co-firing will likely force the Deer Creek Station facility to rely on whichever hydrogen production or storage facility is closest to the facility. This issue is compounded by the fact that the Deer Creek Station facility is sited in a rural area that is likely to be among the last areas where hydrogen production and storage projects will be sited. To mitigate the risk of lapses in power production and service to rural communities, Basin Electric will need to secure backup sources of hydrogen that will likely take even longer to develop. EPA does not even identify this as an issue in the Proposed Rule.

Rather than meaningfully consider the steps necessary to shift the nation's fuel source from natural gas to hydrogen and an unprecedented scale and pace, EPA simply projects that "[s]uitable volumes of low-GHG hydrogen are expected to be produced by the 2032 and 2038 timeframes to satisfy the demand driven by this proposed rule."[123] EPA's analysis is insufficient for the following reasons:

a) EPA does not estimate the amount of hydrogen necessary to support widespread hydrogen co-firing

While EPA speculates that there will be sufficient low-GHG hydrogen production to support hydrogen co-firing, the Proposed Rule does not include an estimate of how much low-GHG hydrogen will be needed. Without identifying this target, EPA cannot reasonably project that hydrogen production will meet it. As discussed below, EPA repeatedly cites to speculative estimates by the DOE that the United States could produce 10 MMT of hydrogen by 2030 and 20 MMT of hydrogen by 2040.[124] However, EPA does not compare this estimate or its other projections against an estimate of how much hydrogen will be needed. Without grounding the analysis with this target, EPA's projection that hydrogen production will be sufficient is unreasonable. Indeed, based on the amount of natural gas burned at combined cycle facilities to generate electricity in 2022, the United States may need to produce upwards of 45.45 MMT of low-GHG hydrogen for it be possible for affected facilities to comply with the Proposed Rule.[125]

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[122] *Id.* at 33,313–14.
[123] *Id.* at 33,364.
[124] *See e.g., id.* at 33,309.
[125] Basin Electric calculated this estimate based on data from the Energy Information Administration that the United States used 12.12 trillion cubic feet of natural gas to produce electricity in 2022 and that combined-

b) EPA relies on the speculative impacts of new federal funding programs and projections by the DOE

EPA claims that the federal subsidies, loans, and other incentives included in the Infrastructure Investment and Jobs Act of 2021 ("IIJA") and the Inflation Reduction Act of 2022 ("IRA") "are anticipated to significantly increase the availability of low-GHG hydrogen."[126] While the IIJA and IRA contain several programs to promote hydrogen infrastructure, they are new and their long-term impact on the production of hydrogen is unknown. EPA highlights that, based on these programs, the DOE has "indicated its intention to fund between six and 10 [hydrogen] hubs."[127] Additionally, EPA claims that hundreds of new low-GHG hydrogen production and infrastructure projects "had been announced" since the passage of the IIJA and the IRA.[128] However, EPA offers no explanation of how and when these "intentions" and "announcements" will lead to the construction of the massive, integrated system of hydrogen infrastructure that is required to support hydrogen co-firing. EPA is purely speculating that these federal incentives will be enough to create an entirely new and sustainable industry of hydrogen production, storage, and transportation that is sufficient to support the requirements of the Proposed Rule.

Related to its reliance on the impact of these federal programs, EPA repeatedly cites to the DOE's "U.S. National Clean Hydrogen Strategy and Roadmap" ("DOE Roadmap") that references the possible influence of these federal programs. The DOE Roadmap lays out potential pathways for the United States to achieve hydrogen production of 10 MMT by 2030 and 20 MMT by 2040.[129] Importantly, this estimated hydrogen production would not be available to power generators alone but would be split between the transportation and industrial sectors as well. Further, the DOE Roadmap itself characterizes these estimates as "clearly ambitious" and emphasizes that they are based on "cost-driven demand scenarios" that "assum[e] cost competitiveness for hydrogen" across these different sectors.[130]

Cost competitiveness between the power generation sector and the transportation sector is highly unlikely due to the difference in costs between the fuels that these sectors currently rely upon. The cost to power plants of generating electricity from natural gas is currently $3.50/MMBTU whereas the transportation industry largely relies on diesel fuel,

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cycle systems account for more than half of the energy generation from natural gas-fired power plants. *How much natural gas is consumed in the United States*, EIA.GOV (April 28, 2023), https://www.eia.gov/tools/faqs/faq.php?id=50&t=8; *Most combined-cycle power plants employ two combustion turbines with one steam turbine*, EIA.GOV (April 25, 2022), https://www.eia.gov/todayinenergy/detail.php?id=52158.

[126] *Id.* at 33,312.

[127] 88 Fed. Reg. at 33,312.

[128] *Id.*

[129] *See e.g., id.* at 33,309.

[130] U.S. DOE, NATIONAL CLEAN HYDROGEN STRATEGY AND ROADMAP 13, 21 (September 2022), https://www.hydrogen.energy.gov/pdfs/cleanhydrogen-strategy-roadmap.pdf.

which currently costs $29.69/MMBTU.[131] If the United States market for low-GHG hydrogen achieves the goal set by the DOE, then hydrogen would cost $7.4/MMBTU.[132] Transitioning to hydrogen would currently represent a massive reduction in fuel costs for the transportation sector but over a doubling of fuel costs for the power generation sector. Even as the price of these fuels fluctuate, the demand for hydrogen will be far greater in the transportation sector and the power sector will struggle to compete for the available hydrogen. Cost competitiveness between the power generation sector and the transportation sector is, therefore, a flawed assumption.

Finally, the estimates in the DOE Roadmap do not apply to the production of "low-GHG" hydrogen as defined in the Proposed Rule. EPA considered several different definitions contemplated in other federal regulations but decided to define the term as "hydrogen produced through a process that has a GHG emissions rate of 0.45 kg CO_2e/kg H2 or less, from well-to-gate."[133] This definition is the most aggressive of the options that EPA considered and represents the GHG emission rate eligible for the highest available tax credit.[134] However, as EPA notes, the estimates in the DOE Roadmap "do not apportion which type of hydrogen is likely to be produced, just that it is 'clean.'"[135] Thus, the estimates in the DOE Roadmap cannot be relied upon to support EPA's already speculative claim projection that the IIJA and IRA will ensure the necessary development of hydrogen infrastructure.

c) EPA relies on the speculative goals of proposed projects

As mentioned above, EPA relies on the goals of announced hydrogen infrastructure projects to support its projection.[136] Forecasting what is achievable based on the specific plans and aspirations of individual generators amounts to "mere speculation."

For instance, EPA prominently highlights Intermountain Power Agency's ("IPA") partnership with ACES Delta to develop a hydrogen production and storage facility adjacent to IPA's stationary combustion turbine in Delta, Utah.[137] The circumstances of that project are exceedingly rare, if not unique, and cannot be extrapolated to the entire country. ACES Delta plans to site its hydrogen hub immediately adjacent to the IPA facility because of the presence of a mile-wide salt dome, a portion of which is underneath the IPA

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[131] *See Natural Gas Prices*, EIA.GOV (July 31, 2023), https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm (providing the most recent industrial price of natural gas in the U.S. as of May 23, 2023); *Gasoline and Diesel Fuel Update*, EIA.GOV, https://www.eia.gov/petroleum/gasdiesel/ (last visited August 4, 2023) (providing the most recent price of on-highway diesel fuel as of July 31, 2023). To calculate the current price of natural gas, Basin Electric converted from the U.S. Energy Information Administration ("EIA") price from $/Mcf to $/MMBTU. To calculate the current price of diesel fuel, Basin Electric converted the EIA price from $/gal to $/MMBTU by using the heating value of diesel fuel, is approximately 139,000 BTU/gal, in the following formula: ($4.127/gal) * (1 gal diesel / 139,000 BTU) * 1,000,000 BTU/MMBTU = $29.69/MMBTU.
[132] 88 Fed. Reg. at 33,314.
[133] *Id.* at 33,304.
[134] *Id.*
[135] *Id.* at 418.
[136] *Id.* at 33,312–13, 33,365.
[137] *Id.* at 33,312, 33,365.

facility.[138] This is the only such salt dome in the Western United States.[139] This unique geologic feature will allow ACES Delta to construct large salt caverns in which to store the hydrogen that it produces.[140] The presence of the salt dome also allows for the cost-efficient piping of the hydrogen a short distance to the IPA facility.[141]

Basin Electric does not have the luxury of a massive salt dome next door to its existing combustion turbines. Without such a unique geologic feature nearby, Basin Electric's facilities, like most existing turbines, will be reliant on wherever proposed hydrogen hubs are sited. Transporting the hydrogen from those production facilities to Basin Electric's turbines may require hundreds if not thousands of miles of pipelines.

Moreover, the plans and goals of proposed projects provide no guarantee or even reasonable likelihood of the amount of hydrogen that will actually be produced if and when such projects are constructed. EPA references proposed projects announced by utilities to produce low-GHG hydrogen or supply hydrogen producers with low-GHG power to do so.[142] But goals and plans announced at the outset of large power projects are liable to change and are susceptible to innumerable issues regarding funding, construction, continued supply chain delays, and labor shortages. Accordingly, the initial plans and goals of such proposed projects are speculative and do not provide a reasonable basis to project the development of the necessary hydrogen infrastructure.

d) EPA fails to consider the significant challenge of obtaining additional water, particularly in the West

EPA highlights electrolysis as the primary process for producing low-GHG hydrogen and incorporates the use of this process into its projection that sufficient hydrogen will be available to support hydrogen co-firing.[143] As EPA acknowledges, hydrogen electrolysis requires "the use of more water, compared to other methods of producing hydrogen."[144] Indeed, electrolysis requires approximately nine pounds of water to produce a single pound of hydrogen. However, EPA does not consider how the availability of water will be a limiting factor in the development of the necessary hydrogen infrastructure, particularly in the West where Basin Electric's Deer Creek Station facility is located. Water in the West is fundamentally scarce and has become extremely difficult to acquire due to decades of

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[138] Jason Compton, *In Utah, Hydrogen And A Massive Salt Dome Are Winning The West For Renewable Energy, Forbes* (March 13, 2020 at 11:43 am), https://www.forbes.com/sites/mitsubishiheavyindustries/2020/03/13/in-utah-hydrogen-and-a-massive-salt-dome-are-winning-the-west-for-renewable-energy/?sh=5c6d7f7c5c52; see Advanced Clean Energy Storage Hub, Aces Utah, https://aces-delta.com/hubs/ (last visited July 20, 2023).
[139] Sonal Patel, *ACES Delta's Giant Utah Salt Cavern Hydrogen Storage Project Gets $504M Conditional DOE Loan Guarantee*, POWERMAG.COM (April 28, 2022), https://www.powermag.com/aces-deltas-giant-utah-salt-cavern-hydrogen-storage-project-gets-504m-conditional-doe-loan-guarantee/.
[140] *See Advanced Clean Energy Storage Hub*, ACES-DELTA.COM, https://aces-delta.com/hubs/ (last visited July 20, 2023).
[141] *See id.*
[142] *See* 88 Fed. Reg. at 33,312, 33,365.
[143] *See id.* at 33,304, 33,307, 33,309–13.
[144] *Id.* at 33,315.

persistent drought. Accordingly, the scarcity of water will pose a significant challenge to the development of low-GHG hydrogen production in the West. EPA simply ignored this challenge in projecting that the necessary low-GHG hydrogen infrastructure will be available.

3. *EPA Fails to Meet the Standard for Justifying a "Technology-forcing" Regulation.*

In its discussion of the definition of BSER, EPA emphasizes that CAA Section 111 provides EPA with the authority "to create incentives for new technology" and requires that EPA consider "technological innovation."[145] EPA invokes this authority in its proposed determination that hydrogen co-firing is a BSER for existing stationary combustion turbines because EPA intends for this determination to incentivize significant technological and infrastructure advancements.[146]

However, EPA fails to meet the standard for justifying such a "technology-forcing" regulation because the Proposed Rule does not "identify the major steps necessary for development of the [technology], and give plausible reasons for its belief that the industry will be able to solve those problems in the time reaming."[147] As explained above, the Proposed Rule includes scant technical analysis on the state of hydrogen co-firing technology. While EPA notes the general issues that the characteristics of hydrogen pose for co-firing at base load turbines, EPA does not identify any of the technical steps necessary to solve these issues. Even if EPA had identified the major steps, EPA does not provide plausible reasons for its claim that manufacturers will be able to overcome these significant issues in the time remaining. Instead, EPA relies on the speculative plans and goals of manufacturers and select power generators.

Moreover, this BSER determination is distinguishable from past "technology-forcing" regulations under the CAA where EPA used new standards to drive innovation within the industries that had control over the technology at issue.[148] In *API v. EPA*, the court vacated EPA's 2012 projection of biofuel production as a means to force transportation fuel producers to incorporate higher levels of biofuels due to an asymmetry of incentives.[149] The court explained that:

> EPA applies the pressure to one industry (the refiners)... yet it is another (the producers of cellulosic biofuel) that enjoys the requisite expertise, plant,

145 *Id.* at 33,275 (citing *Sierra Club v. Costle*, 657 F.2d 298, 346 (D.C. Cir. 1981)).
146 *See id.* at 33,275 ("The D.C. Circuit has long held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the 'best system of emission reduction.'") (citing *Sierra Club v. Costle*, 657 F.2d 298, 346 (D.C. Cir. 1981); *id.* at 33,363 (stating that EPA's proposed determination that hydrogen co-firing is BSER for existing base load turbines "will also advance the development and deployment of this low-emitting technology"); *id.* at 33,364 (projecting that "suitable volumes are expected to be produced... to satisfy the demand driven by this proposed rule").
147 *See API v. EPA*, 706 F.3d 474, 480 (D.C. Cir. 2013).
148 *See id.*
149 *Id.* at 476.

> capital and ultimate opportunity for profit. Apart from their role as captive consumers, the refiners are in no position to ensure, or even contribute to, growth in the cellulosic biofuel industry. "Do a good job, cellulosic fuel producers. If you fail, we'll fine your customers. Given this asymmetry in incentives, EPA's projection is not "technology-forcing" in the same sense as other innovation-minded regulations that we have upheld.[150]

EPA's projections that the necessary co-firing technology and hydrogen infrastructure will be commercially available by the implementation deadlines in the Proposed Rule creates the same incentive asymmetry. The proposed regulations apply pressure to operators of existing base load turbines, while it is the manufacturers of the turbines and developers of hydrogen infrastructure that enjoy the requisite expertise and opportunity to profit. Operators of turbines are not in a position to ensure that these manufacturers and developers will overcome the challenges of achieving high levels of hydrogen co-firing and developing the necessary hydrogen production, storage, and transportation in time. Indeed, Basin Electric does not have control over the content of the natural gas that its facilities receive from the available pipeline network—that authority resides with the companies that operate the pipelines. However, if the manufacturers and developers fail, the regulatory consequences will fall upon the operators of the turbines, including Basin Electric. Thus, EPA cannot claim that this BSER determination is a "technology-forcing" regulation in the same sense as other BSER determinations that courts have upheld, such as in *Sierra Club v. Costle*, 657 F.2d 298, 346 (D.C. Cir. 1981).

4. <u>EPA's Cost Estimates are Unreasonable</u>

EPA's estimated costs to retrofit existing plants to co-fire hydrogen are cost-prohibitive and unreasonable. EPA anticipates that it will cost "$10–$60/kW in retrofit costs to achieve 30–60% hydrogen blending by volume" and "roughly $100/kW" for "blend levels in the range of 60–100%."[151] EPA also predicts that, relative to firing natural gas, capital costs for hydrogen co-firing will be $70/kW higher, fixed operating costs will be $1/year per kW higher, and non-fuel operating costs will be $0.5MWh higher.[152] These cost estimates are unreasonable given EPA's acknowledgement that costs "could be higher for retrofits to combustion turbines."[153] Moreover, EPA failed to meaningfully consider several significant cost factors including the unprecedented infrastructure investment that will be necessary to support widespread hydrogen co-firing, additional water required to co-fire hydrogen, and New Source Review ("NSR") permitting. EPA's failure to address these factors renders its cost estimates unreasonable.

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[150] *Id.* at 480.
[151] 88 Fed. Reg. at 33240, 33365.
[152] *Id.* at 33365–66.
[153] *Id.*

a) EPA fails to consider several cost factors related to infrastructure and the availability of water

EPA failed to fully account for the staggering cost of the infrastructure required for hydrogen co-firing, which will, in turn, increase the cost of hydrogen that Basin Electric would need to purchase to power its turbines. These include capital costs for retrofitting facilities, implementing proper pipeline infrastructure, and addressing fuel costs for transportation. EPA assumes that because other manufacturers are developing combustion turbines that can co-fire 100% hydrogen, this somehow limits the amount of additional costs needed to build infrastructure for combustion turbines that meet the 30% co-firing requirement of the Proposed Rule.[154] However, EPA acknowledges that certain costs related to such turbines would be more expensive: "the heat rate of a hydrogen-fired combustion turbine model plant is 5 percent higher and the capital, fixed, and non-fuel variable costs are 10 percent higher than a natural gas-fired combustion turbine."[155] While EPA recognizes that such combustion turbines are more expensive than natural gas combustion turbines, EPA's projections lack data supporting its findings that these additional costs would be limited.

Moreover, EPA failed to meaningfully consider the significant cost of additional water that will be needed to operate stationary turbines that co-fire hydrogen. Co-firing hydrogen requires the use of water to cool the resulting increase in oxides of nitrogen ("NOx") exhaust gas. Hydrogen co-firing significantly increases the volume of NOx exhaust gas from the combustion process because NOx formation increases with temperature, and hydrogen combustion occurs at a temperature 435°F hotter than methane combustion. The amount of exhaust gas will also greatly increase due to the lower energy efficiency of hydrogen combustion which will require burning more than three times the amount of hydrogen to replace the energy output of methane natural gas. As a result, 96% hydrogen co-firing will emit more than triple the amount of exhaust gas as compared to natural gas combustion. Accordingly, operators of stationary combustion turbines will need to acquire significant volumes of water to cool this massive increase in NOx exhaust.

Basin Electric's Deer Creek Station facility currently does not use water to cool the exhaust gas from its natural gas-fired turbines. To convert the facility to 30% and then 96% hydrogen co-firing, Basin Electric would have to find and purchase significant volumes of water. Doing so would be prohibitively difficult because, as is the case throughout the West, water is fundamentally scarce and has become extremely expensive to acquire due to decades of persistent drought.

In a technical support document, EPA acknowledges that the water requirements for hydrogen co-firing "would be greater than [for] combined cycle EGUs with CCS."[156] However, in its cost analysis, EPA failed to consider the significant cost of obtaining the additional water required to transition to hydrogen co-firing, particularly for facilities in

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[154] *Id.* at 33312.

[155] 88 Fed. Reg. at 33240, 33313.

[156] U.S. EPA, HYDROGEN IN COMBUSTION TURBINE ELECTRIC GENERATING UNITS TECHNICAL SUPPORT DOCUMENT 20 (May 23, 2023) (Docket ID No. EPA-HQ-OAR-2023-0072).

the West. The sheer amount of water that the Deer Creek Station facility would need to acquire to continue operation renders the hydrogen co-firing economically infeasible for Basin Electric. Indeed, Basin Electric would not have sited the Deer Creek Station facility in its current location had it known that it would need large volumes of water to operate its turbines.

b) EPA underestimates the costs of upgrading pipeline infrastructure

EPA also failed to adequately account for the costs to upgrade current pipeline infrastructure to meet the water and hydrogen needs of Basin Electric's facilities. The current pipeline infrastructure for transporting hydrogen is severely underdeveloped and unable to meet the demand created by this Proposed Rule. Currently, there are 3 million miles of natural gas pipelines; however, only 1,600 miles of these pipelines are dedicated to the transportation of hydrogen.[157] EPA does not appropriately account for the inadequacy of hydrogen pipeline infrastructure and the costs associated with building such pipelines. Additionally, EPA recognizes that current natural gas pipelines would be unable to handle higher concentrations of hydrogen, as it would cause these pipelines to become embrittled or leak.[158]

Nonetheless, EPA asserts that because the "majority of . . . announced EGU projects . . . are located close to the source of hydrogen . . . the fuel delivery systems (i.e. pipes) for new combustion turbines can be designed to transport hydrogen without additional costs."[159] EPA claims that this would then limit, or eliminate, the cost of transporting hydrogen to stationary turbines.[160] While this could be true for newly announced combustion turbines, these conditions do not exist for the Deer Creek Station facility. Basin Electric is not aware of any existing or planned hydrogen transportation infrastructure close to the Deer Creek Station facility that would be sufficient to support 30% and 96% hydrogen co-firing. Without such infrastructure, Basin Electric would itself be forced to invest in the new construction of pipelines to connect the Deer Creek Station facility to the closest source of hydrogen, wherever that may be. As EPA merely assumes that the necessary hydrogen infrastructure will be close to power plants, EPA fails to adequately account for such infrastructure costs for facilities like the Deer Creek Station.

c) EPA fails to incorporate costs from impending New Source Review permits under State Implementation Plans

Retrofitting turbines to burn higher percentages of hydrogen will increase NOx emissions at levels likely to trigger major New Source Review ("NSR") under the CAA. As

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[157] *Hydrogen infrastructure expansion requires realistic framework*, OIL AND GAS JOURNAL, (May 21, 2021) https://www.ogj.com/pipelines-transportation/article/14202928/hydrogen-infrastructure-expansion-requires-realistic-framework.
[158] 88 Fed. Reg. at 33,240, 33,313.
[159] *Id.* at 33,314.
[160] *Id.*

acknowledged in the Proposed Rule[161] and explained above, hydrogen co-firing significantly increases NOx emissions as compared to natural gas combustion due to the higher temperature and lower energy efficiency of hydrogen combustion. To the extent that these increased NOx emissions trigger permitting—and particularly major source permitting—NSR will complicate the installation of hydrogen co-firing equipment. As EPA acknowledges, sources may ultimately have to control the resulting increase in NOx emissions with additional control technologies such as SCR.[162] However, EPA failed to incorporate the cost of these expensive controls and NSR permitting into its economic analysis of hydrogen co-firing.

d) EPA's cost estimates are highly speculative because they rely on proposed projects and assumptions on available funding

EPA inappropriately relies on announcements for proposed projects and their anticipated costs to support its cost estimates for hydrogen co-firing. EPA claims that "[t]he fact that existing sources are already planning to combust low-GHG hydrogen, even in the absence of a regulatory requirement, is an indication that the costs of co-firing are reasonable."[163] However, these sources that are "planning" to co-fire hydrogen provide little evidence that such costs would be reasonable for other regulated sources. For instance, EPA notes that Constellation Energy Corporation "has estimated the costs to retrofit existing plants to co-fire hydrogen and has indicated that they are reasonable."[164] However, what makes these costs "reasonable" is unclear and not explained in the Proposed Rule.

As noted above, EPA also highlights the proposed ACES Delta project to produce low-GHG hydrogen and store it in an underground salt dome to support hydrogen co-firing at IPA's existing stationary turbine facility.[165] However, this proposed project only has the potential to be economically feasible because of the unique geology of the salt dome that can support siting a hydrogen hub adjacent to IPA's facility. Further, EPA can only speculate on whether this proposed project will ultimately support 96% hydrogen co-firing at IPA's facility, despite any goals announced for project.

EPA also relies on theories and assumptions that, in the future, manufacturing improvements, federal incentives, and further research will drive down costs of hydrogen storage:

> It is expected that with additional cost reductions in carbon fiber and improved manufacturing methods, these technologies could ultimately cost less than the traditional metal Type I cylinders. . . [T]he use of geographically agnostic technologies such as buried pipes, hard rock caverns, and depleted hydrocarbon

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[161] *Id.* at 33,364 ("One concern with hydrogen co-firing is that, because it burns at a higher temperature, it has the potential to generate more thermal NOx.").
[162] *Id.* at 33,350.
[163] *Id.* at 33,365.
[164] 88 Fed. Reg. at 33,365.
[165] *Id.*

> reservoirs and aquifers. As the demand for bulk hydrogen storage grows, it is likely to incentivize accelerated R&D and first-of-its-kind deployments of such innovative technologies, which could in turn reduce the cost of infrastructure across sectors with large-scale hydrogen demand.[166]

However, EPA cites no support for its predictions for costs and research and development, and it fails to address current costs for storage for the source category as a whole. Such assumptions and reliance on potential innovations and cost reductions does little to ensure Basin Electric will have the necessary capital and storage to meet its operational demand for hydrogen.

The EPA also speculates that costs of implementing hydrogen co-firing technologies will be adequately subsidized by impending tax credits. EPA surmises that incentives from the IIJA and the IRA tax subsidies for low-GHG hydrogen will adequately reduce fuel costs, thus ensuring EPA's timeline for implementation of the BSER. But the impacts of these new programs are only speculative at this point.[167]

In addition, EPA uses estimated amounts to arrive at projected fuel costs, and such estimates incorporate available IIJA subsidies and credits to help reduce such expenditures. This assumption is highly speculative and, thus, unreasonable. EPA derives its estimated costs from anticipated projects and initiatives that have yet to come to full fruition. EPA highlights one such example of a facility in California: the "HyDeal initiative in Los Angeles is anticipated to deliver low-GHG hydrogen for less than $2/kg by 2030. This initiative brings together the entire value chain across the LA Basin, including production, transport, storage, and multi-sectoral aggregated offtake."[168] EPA also acknowledges that it, and the DOE have "the goal of reducing the cost of clean hydrogen to $1 per kilogram within a decade."[169] But such a goal provides neither a guarantee nor even a likelihood that market will achieve that cost. Indeed, the future cost of low-GHG hydrogen is highly uncertain. While EPA tries to assuage such concerns with promises of tax credits, the actual impact of future tax credits is largely speculative and makes such future costs unreasonable.

C. EPA's Proposed Timelines Are Unreasonable

EPA's implementation deadlines in its proposed BSER determinations for CCS and hydrogen co-firing are unreasonable and present requirements with which Basin Electric cannot comply. As discussed in Section IV.C., the implementation deadline for CCS fails to meaningfully account for challenges concerning planning, design, customization,

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[166] *Id.*
[167] In addition, and as described above, EPA is prohibited from considering projects subsidized by the DOE's Clean Coal Power Initiative or funded by a Qualifying Advanced Coal Project Tax Credit under section 48A of the IRC to support an "adequately demonstrated" finding. *See* 42 U.S.C. § 15962(i); 26 U.S.C. § 48A(g). This same policy–not considering government incentives and subsidies when determining BSER–should extend to EPA's consideration of other subsidies, credits, and government incentives in determining BSER.
[168] U.S. EPA, HYDROGEN IN COMBUSTION TURBINE ELECTRIC GENERATING UNITS TECHNICAL SUPPORT DOCUMENT 34 (May 23, 2023) (Docket ID No. EPA-HQ-OAR-2023-0072).
[169] *Id.* at 35.

construction, labor, continued supply chain shortages, optimization, and infrastructure development.

EPA's implementation deadlines for hydrogen co-firing fail to consider many of the same issues. Retrofitting Basin Electric's existing fleet of turbines is a complicated process that requires detailed coordination of factors regarding design, procurement of materials, and labor. To prevent any disruption to the power provided to its customers, Basin Electric must conduct retrofits during shutdown events that are also planned far in advance.

Complying with the 30% and 96% hydrogen requirements of the BSER will necessitate at least two retrofits of Basin Electric's turbines within the next fifteen years. Additionally, Basin Electric can only begin planning to retrofit its turbines to co-fire 96% hydrogen once manufacturers have confirmed that the technology to do so is commercially viable, insurable, and the necessary materials are available. Depending on how the pace of the technological innovation aligns with the shutdown schedule and the ongoing supply chain shortages, the actual implementation of 96% hydrogen co-firing at Basin Electric's turbines could take place years after the technology is commercially viable. As the timelines for developing this technology as well as the necessary infrastructure to support the technology are highly speculative, imposing a strict deadline at this point is unreasonable and incompatible with the long-term planning necessary for Basin Electric to retrofit the turbines.

VII. EPA Should Not Lower the Applicability Threshold for Baseload Combustion Turbines

EPA proposes to apply the BSER determinations of CCS and hydrogen co-firing to existing stationary combustion turbines with a capacity greater than 300 MW and a capacity factor greater than 50%. EPA requests comment on whether it should lower this threshold and apply the BSER determinations to smaller, less frequently used turbines.[170]

Lowering the applicability threshold would subject more combustion turbines to the infeasible technological requirements and unreasonable timelines imposed by these BSER determinations. Furthermore, every additional combustion turbine that must implement CCS or hydrogen co-firing decreases the likelihood that the necessary infrastructure to support these technologies will be developed by the deadlines in the BSER determinations. As explained above, the infrastructure development required to support CCS and hydrogen co-firing at existing base load turbines would be unprecedented both in scale and pace. Subjecting more turbines to these BSER determinations would require even more facilities to support CCS as well as hydrogen production, storage, and transportation. As EPA's projections that this infrastructure will be available by the applicable deadlines are already unreasonable, EPA should not compound its mistake by decreasing the applicability threshold for existing turbines subject to the Proposed Rule. Ultimately, imposing these

[170] 88 Fed. Reg. at 33,246, 33,370.

unreasonable BSER determinations on more turbines would further inflate the cost and threaten the reliability of energy beyond what the current Proposed Rule would cause.

VIII. EPA Does Not Properly Categorize or Regulate New Combustion Turbine EGUs

A. EPA Sets the Threshold for Low Load Combustion Turbines Too Low

Utilities, including Basin Electric utilize small, simple cycle units to offset renewable, intermittent generation such as wind and solar. Because renewable generation sources are not dispatchable, fast-start, firm generation must be in place for times when wind and solar resources are not available. Basin Electric relies on natural gas-fired simple cycle combustion turbine EGUs to fill this gap. EPA has proposed to limit new "low load" combustion turbines to less than or equal to 20% of the turbine's potential electric sales.[171] Limiting these units to less than or equal to 20% of the turbine's potential electric sales underutilizes highly efficient machines that are necessary for continued development of renewables. New simple cycle natural gas turbines are currently limited under the existing TTTT rule.[172] Further limiting these units will result in less renewables that are able to be added to grid and further exacerbating reliability concerns. Additionally, EPA's determination that a capacity factor of 20% is the defining line between low and intermediate load has no basis. Many of these units run significantly more than 20% and will continue to do so, particularly in areas of high renewable penetration and high transmission congestion. EPA should retain the current TTTT limits for simple cycle turbines.

B. The Existing TTTT Rules for New Combined Cycle Units are Sufficient

EPA has requested comment on whether or not steam units should be included in the intermediate load category for new combustion turbines. Additionally, EPA has requested comment on whether the intermediate load category should be further subcategorized.[173] The existing TTTT rules for new combined cycle units are sufficient to ensure that new combined cycle units are being built using the most efficient technology available. Further restricting these units will result in less support for renewable resources that are trying to add to the grid because without firm capacity to support those resources, grid stability is called further into question. EPA further confuses the issue by using the term "turbine" interchangeably when referring to simple cycle units or combined cycle units with associated steam equipment.

[171] 88 Fed. Reg. at 33,321.
[172] 40 C.F.R. part 60, subpart TTTT
[173] 88 Fed. Reg. at 33,332.

IX. EPA Does Not Adequately Assess the Substantial Impacts the Proposed Rule Will Have on Resource Adequacy and Grid Reliability

As outlined above, CAA Section 111 requires EPA to take into account "energy requirements" when determining the best system of emission reduction.[174] While EPA purports to have "carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals and is confident that [the emissions guidelines] . . . 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,"[175] EPA has not acknowledged or appreciated the risk that the Proposed Rule poses to the reliability of the power grid.

Basin Electric and other power generators rely on diverse energy portfolios to meet America's demand for power. As much as Basin Electric and others support a transition to cleaner energy sources, that transition must take into account the increasing demand for power, the importance of high-megawatt baseline power, the limitations of the existing grid systems, and the gridlock in bringing new clean energy projects onto the grid. The bottom line is that no matter how much EPA wants to force a transition to cleaner energy, America's dependable fossil fuel-fired power sources cannot be rapidly replaced, nor replaced on a one-for-one basis, with clean energy sources.

If EPA had consulted with the appropriate industry stakeholders, it would know better. While the Proposed Rule states that EPA consulted with the DOE and the Federal Energy Regulatory Commission ("FERC") in the development of these proposals,[176] EPA failed to consult with the North American Electric Reliability Corporation ("NERC"), or any other Independent System Operators or Regional Transmission Organizations that are certified by FERC (collectively, "System Operators") in charge of ensuring electric reliability within regional markets.

EPA's Proposal, which will force owners and operators of EGUs like Basin Electric to spend crippling amounts of money and shut down operations for retrofitting, or shutter units entirely to avoid complying with the strict emissions limitations, poses real risks to America's electric grid and disproportionately impacts communities with environmental justice concerns. EPA did not consider any of these real risks, especially in conjunction with the other regulations applicable to EGUs that EPA has promulgated over the last few years.

A. Electric Cooperatives Like Basin Electric Rely on Diverse Energy Portfolios to Maintain Reliability

Basin Electric and other power companies and cooperatives rely on diverse asset portfolios to generate and dispatch electricity in a reliable and cost-effective manner. Even

[174] *See* 42 U.S.C. § 7411(a)(1).
[175] 88 Fed. Reg. at 33,246.
[176] *Id.* at 33,247,

as Basin Electric drives towards greater reliance on renewable energy, coal and gas will remain critical for Basin Electric to meet the Nation's growing energy demands.

Basin Electric's 2023 load forecast projects growth of 1.14% over the next ten years.[177] Basin Electric's projected growth is driven by the residential and commercial sectors, as well as high density computing facilities, the projected emergence of agriculture-based CO_2 capture and sequestration, and continued economic development in western North Dakota.[178]

Basin Electric relies on an all-of-the-above energy strategy for maintaining a reliable electric system. This strategy employs a diversified portfolio of dispatchable and non-dispatchable resources.[179] The distinction between these resources is that dispatchable resources have a readily available fuel supply to power their generation, whereas non-dispatchable resources rely on intermittent, renewable fuel and produce electricity when weather conditions permit.

The majority of Basin Electric's dispatchable resources — coal, natural gas, and fuel oil generation facilities — are situated in relatively close proximity to the mines, wells, and pipelines that provide their fuel. This proximity enhances reliability, lowers costs, and reduces the environmental footprint of our dispatchable resources.[180]

Its portfolio of non-dispatchable, renewable resources, currently consisting of wind facilities, has a generating capacity of more than 1,800 MW of electricity. Basin Electric's system also benefits from access to hydroelectric power, which provided approximately 4.3% of its winter season generating capacity in 2022.

Its all-of-the-above energy strategy capitalizes on Basin Electric's service territory being one of the best areas in the nation for wind generation. In the past decade, Basin Electric has added nearly 1,200 MW of wind resources to its portfolio, and will soon add solar generation to its portfolio through a power purchase agreement with a new solar project under construction in South Dakota.[181] Basin Electric is also pursuing its largest single-site electric generation project since the 1980s. It is constructing approximately 600 MW of natural gas generation near the existing Pioneer Generation Station, northwest of Williston, North Dakota.[182]

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[177] *See* BASIN ELECTRIC POWER COOPERATIVE, 2022 ANNUAL REPORT, 6, https://www.basinelectric.com/_files/pdf/financials/Annual-Report-2022-Web.pdf (submitted as "Attachment 5 – Excerpt from Basin Electric 2022 Annual Report").
[178] *Id.*
[179] *Id.* at 4.
[180] *Id.*
[181] *Id.*
[182] *Id.* at 6.

Separately, Basin Electric is on track to energize nearly 350 miles of high-voltage transmission line in western North Dakota by the end of 2027.[183] These projects are being constructed to address concerns with future reliability and service. The two 230-kV transmission lines that will connect with SaskPower at the Canadian border will support reliability by providing larger transfer capability between Canada and the Southwest Power Pool ("SPP") system, a regional transmission organization of which Basin Electric is a member.[184]

Basin Electric also serves load, and develops plans to serve future load growth, with power purchase agreements and energy and capacity purchases.[185] Basin Electric entered into a 200-MW power purchase agreement with ENGIE North America in December of 2022 for the output of its North Bend Wind Project in Hughes and Hyde counties in South Dakota. The project is set to begin commercial operation in 2023.[186] In addition, Basin Electric began receiving 142 MW from the Aurora Wind Project near Tioga, North Dakota, on Jan. 1, 2023.[187]

Basin Electric must also ensure that it generates sufficient electricity to support voltage and frequency stability. Significant losses of dispatchable and reliable baseload generating capacity would result in reduced voltage and frequency stability, another threat the Proposed Rule poses to the nation's grid.

In short, to meet its members' growing demand, Basin Electric must depend on a combination of energy sources; it cannot shutter its coal-fired EGUs.

B. Substitution of Energy Sources is Further Complicated Because Basin Electric Has Limited Capacity to Transfer Power Across the Electric Grids

The Nation's electric grid is comprised of three regional grids that are not fully interconnected: the Eastern, Western, and Texas Interconnections. Basin Electric's system straddles two of the regional grids: the Eastern Interconnection and the Western Interconnection.[188] These two grids operate with different electrical characteristics that prevent electricity on one side of the national grid from being delivered directly to the other.[189]

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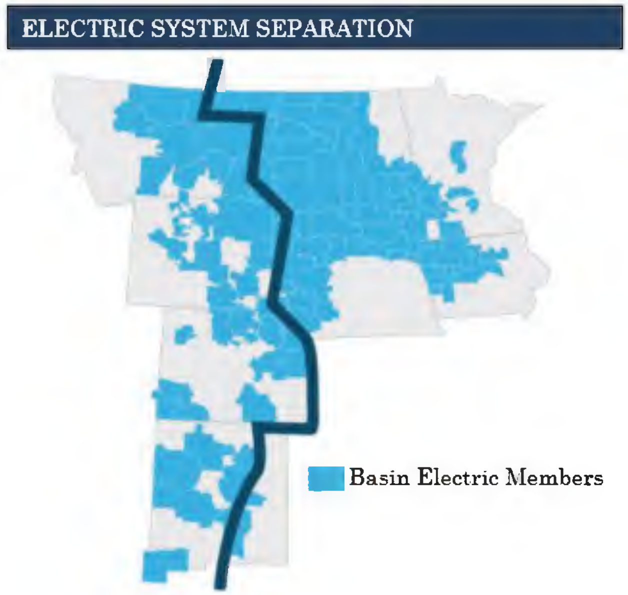
[183] BASIN ELECTRIC POWER COOPERATIVE, 2022 ANNUAL REPORT, 6, https://www.basinelectric.com/_files/pdf/financials/Annual-Report-2022-Web.pdf (submitted as "Attachment 5 – Excerpt from Basin Electric 2022 Annual Report").
[184] *Id.*
[185] *Id.*
[186] *Id.*
[187] *Id.*
[188] BASIN ELECTRIC POWER COOPERATIVE, OPTIONAL INTEGRATED RESOURCE PLAN, 2 (June 30, 2021) [hereinafter "2021 Minnesota O-IRP"]. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bE0F5617A-0000-CF1F-95DD-59E10E30D791%7d&documentTitle=20216-175739-01.
[189] *Id.*



Basin Electric's system straddles the Eastern and Western grids and serves separate markets; it cannot redispatch wind energy generated on the Eastern grid to replace coal-fired energy generated on the Western grid. Shifting energy across the seam between the Eastern and Western Interconnections to supplement energy production with cleaner energy sources would require countless regulatory approvals and a major overhaul of the transmission facilities linking the two interconnections.

For power to be transferred between the East and West systems, alternating current ("AC") electricity must be converted into direct current ("DC") electricity to cross the seam and then must be converted back to AC. Electricity cannot, therefore, simply flow between these interconnections. Moreover, there are only limited amounts of physical transfer capacity between the interconnections. There exist only seven back-to-back DC transmission facilities that allow for a very small amount of capacity, 1,320 MW of energy, to flow across the seam.[190] Basin Electric has increased its transmission rights by approximately 50 MW from west to east, but still only has capability to transfer up to 290 MW in total in the west-to-east direction and 373 MW in total in the east-to-west direction, far less than its total generating capacity of more than 7,000 MW.[191]

As a result, Basin Electric must manage electric generating and transmission resources on both sides of the Eastern and Western Interconnections' seam to serve its

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[190] Aaron Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, NATIONAL RENEWABLE ENERGY LABORATORY, 1 (October 2020), https://www.nrel.gov/docs/fy21osti/76850.pdf (submitted as "Attachment 6 – The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids").

[191] *See* BASIN ELECTRIC POWER COOPERATIVE, NORTH DAKOTA TEN YEAR PLAN, 12 (June 1, 2020), https://psc.nd.gov/database/documents/20-0300/001-010.pdf (submitted as "Attachment 7 – Excerpt from North Dakota Ten Year Plan").

member-load requirements.[192] And, significant differences have developed over time in Basin Electric's generation mix on either side of the seam: coal primarily in the West, where coal resources can be cheaply and dependably obtained, and coal, natural gas, and wind largely in the East, where more potential for extensive wind resources exists.[193]

The difficulties with transferring energy across the seam are demonstrated by Basin Electric's coal-fired power plant, the Laramie River Station, near Wheatland, Wyoming. Units 2 and 3 of the Laramie River Station are electrically connected to the western system; they provide a total of 1,140 MW of power to the western system, of which Basin Electric is entitled to receive 627 MW. Unit 1 is electrically connected to the Eastern system; it provides 560 MW of power to the Eastern system and Basin Electric is entitled to receive 92 MW. Basin Electric has members on both the Eastern and Western systems, but it cannot provide generation from units 2 and 3 to customers on the East side unless it utilizes certain DC ties along the seam. Of the 310 MW of transfer capability available in total across the nearby ties at Stegall & Sidney, Nebraska, Basin Electric is limited to only 160 MW of transfer capability from West to East across those ties from the Laramie River Station Units 2 and 3. Likewise, if Basin Electric and the other owners of the Laramie River Station were forced to shutter Laramie River Station Unit 3, the loss of 570 MW of power on the western system could not be easily replaced by wind energy generated on the eastern system—the loss of 570 MW of power exceeds the total capacity of the nearby DC ties.

Thus, without broad changes in both the physical constraints between the Eastern and Western Interconnections, Basin Electric and other utilities that straddle the divide cannot plan to meet member load requirements under a regulatory structure that incentivizes and requires unit shutdowns. Indeed, the Biden Administration recognized these constraints and has made transmission infrastructure a priority to facilitate interstate transmission across these interconnections and the seam separating them[194]—but that effort is decades in the making.[195]

For example, FERC, on June 16, 2022, announced a notice of proposed rulemaking "focused on expediting the current process for connecting new electric generation facilities

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[192] 2021 Minnesota O-IRP, at 2.

[193] *See Generation Facilities Map*, BASINELECTRIC.COM, https://www.basinelectric.com/about-us/Generation/index.

[194] *See* The White House, *FACT SHEET: Biden-Harris Administration Outlines Priorities for Building America's Energy Infrastructure Faster, Safer, and Cleaner* (May 10, 2023), https://www.whitehouse.gov/briefing-room/statements-releases/2023/05/10/fact-sheet-biden-harris-administration-outlines-priorities-for-building-americas-energy-infrastructure-faster-safer-and-cleaner/.

[195] *See* Statement by Emily Sanford Fisher, General Counsel, Corporate Secretary & Senior Vice President, Clean Energy Edison Electric Institute, Before the House Select Committee on the Climate Crisis, 3 (May 20, 2021), https://docs.house.gov/meetings/CN/CN00/20210520/112657/HHRG-117-CN00-Wstate-SanfordFisherE-20210520.pdf ("Transmission projects typically take 7 to 10 years to plan, site, permit, construct, and energize" and there are "many examples of projects that have taken more than a decade from conception to completion . . . .") (submitted as "Attachment 8 – Statement by Emily Sanford Fisher").

to the grid."[196] Although the recently enacted debt ceiling bill directed NERC to conduct a study on the necessity of boosting electricity transfers across grids, FERC Chairman Willie Phillips emphasized that there would not be a delay in a rulemaking on boosting these transfers.[197]

Moreover, there are substantial barriers that must be addressed before large-scale integration of renewable energy sources can be accomplished without negatively impacting the reliability of the electric system. DOE acknowledged in its draft Needs Study that there is a pressing need for additional transmission infrastructure to improve reliability and capacity.[198] The study anticipates need for a 287% increase in transfer capacity, relative to the 2020 system, between Mountain and Plains to meet moderate load and high clean energy futures.[199] Indeed, it is universally acknowledged that new transmission capacity is needed across the United States to support a transition towards a decarbonized energy supply.[200]

Experts predict that reaching President Biden's goals of achieving a 50–52% reduction from 2005 levels in economy-wide net greenhouse gas pollution by 2030 and net-zero emissions economy-wide by 2050[201] "will require a doubling or tripling of the size and scale of the nation's transmission system."[202] There currently exists a shortage of transmission capacity for new wind and solar projects, most of which are built in rural

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[196] *See FERC Proposes Interconnection Reforms to Address Queue Backlogs*, FERC.GOV (June 16, 2022), https://www.ferc.gov/news-events/news/ferc-proposes-interconnection-reforms-address-queue-backlogs; *see also* Improvements to Generator Interconnection Procedures and Agreements, Advance Notice of Proposed Rulemaking, Docket No. RM21-17-000 (June 16, 2022), https://www.ferc.gov/media/rm22-14-000; *but see* Keith Goldberg, *FERC Won't Be Rushed In Crafting Grid Policies* (June 15, 2023), https://www.law360.com/articles/1689286/ferc-won-t-be-rushed-in-crafting-grid-policies-chair-says.
[197] Goldberg, *supra* note 191.
[198] *Grid Deployment Office Releases National Transmission Needs Study for Public Comment and Feedback*, DEP'T OF ENERGY (Feb. 24, 2023), https://www.energy.gov/gdo/articles/draft-doe-study-identifies-pressing-national-electric-transmission-needs (referencing DEP'T OF ENERGY, *National Transmission Needs Study*, Fed. Reg. Doc. 2023-04521 from Docket No. DOE-HQ-2023-0034, https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf [hereinafter "*Needs Study*"]).
[199] *Needs Study*, *supra* note 193 at iv.
[200] *See, e.g.*, Glen Anderson et al., *Modernizing the Electric Grid: State Role and Policy Options*, NATIONAL CONFERENCE OF STATE LEGISLATURES, 2 (updated Sept. 2021) ("investment will be needed to incorporate a more diverse energy supply"), https://www.ncsl.org/energy/modernizing-the-electric-grid (submitted as "Attachment 9 – Excerpt from Modernizing the Electric Grid"); Avi Zevin et al., *Building a New Grid without New Legislation: A Path to Revitalizing Federal Transmission Authorities*, 48 ECOLOGY L.Q. 169, 171 (2021) ("[N]ew long-distance high-voltage transmission lines will be indispensable if the United States is to integrate enough renewable energy generation to decarbonize the electric system in a timely manner. . . .") (submitted as "Attachment 10 – Excerpt from Building a New Grid without New Legislation").
[201] *See* The White House, *FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies* (Apr. 22, 2021), https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.
[202] Aaron Bloom et al., *Transmission Planning for 100% Clean Electricity*, ENERGY SYSTEMS INTEGRATION GROUP, 4 (2021), https://www.esig.energy/wp-content/uploads/2021/02/Transmission-Planning-White-Paper.pdf (submitted as "Attachment 11 - Transmission Planning for 100 Percent Clean Electricity").

areas away from major cities where the energy is consumed.[203] At the end of 2022, there were more than 2,000 gigawatts of generation and storage waiting in interconnection queues throughout the country.[204] Additionally, most projects that apply for interconnection get withdrawn, while those that are built take extended periods of time due to required completion of certain studies prior to operation.[205]

Therefore, substantial upgrades to the Nation's power grids—that EPA failed to consider—are required for the transition to cleaner energies. And, in the meantime, existing coal-fired EGUs on one side of the seam cannot simply be phased out and replaced with renewable sources on another side of the seam to meet energy demands.

C. Basin Electric is Unique in that it Operates in Multiple Markets

Basin Electric is unique and differs from other electric generating companies because it operates in several markets and is thus subject to several sets of requirements in terms of load requirements and reliability constraints. Basin Electric's service area is electrically divided into four assessment areas across the two electrical interconnections. Generation and transmission responsibilities on the Eastern and Western Interconnections are overseen by electricity grid managers or electricity balancing authorities that are certified by FERC (i.e., the System Operators). The System Operators are responsible for ensuring electric reliability within their regional markets.

In the Eastern Interconnection, Basin Electric's system is part of two assessment areas overseen by two System Operators: the SPP and the Midcontinent Independent System Operator ("MISO"). In the Western Interconnection, Basin Electric's system is overseen by the Northwest Power Pool ("NWPP") and the Rocky Mountain Reserve Group ("RMRG"). These System Operators regulate the multiple energy and capacity markets that exist within each regional grid. They also each require utilities like Basin Electric to maintain a certain amount of capacity to ensure reliability during period of high demand.

Thus, Basin Electric's system is subject to certain reliability standards established by FERC and NERC.[206] These reliability standards require that Basin Electric prudently employ sufficient generation capacity accreditation to meet customers' needs.[207] If its

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[203] *Id.* at 8; *see also Queued Up . . . But in Need of Transmission*, DEP'T OF ENERGY (Apr. 2022), https://www.energy.gov/policy/queued-need-transmission (submitted as "Attachment 12 - Queued Up. . . But in Need of Transmission"); *Grid connection requests grow by 40% in 2022 as clean energy surges, despite backlogs and uncertainty*, ELECTRICITY MARKETS & POLICY (Berkeley Lab, Apr. 6, 2023), https://emp.lbl.gov/news/grid-connection-requests-grow-40-2022-clean (submitted as "Attachment 13 - Grid connection requests grow by 40 Percent in 2022 as clean energy surges").

[204] *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, ELECTRICITY MARKETS & POLICY (Berkeley Lab, Apr. 2022), https://emp.lbl.gov/queues (submitted as "Attachment 14 - Queued Up Characteristics of Power Plants Seeking Transmission Interconnection").

[205] *Id.*

[206] *See* 16 U.S.C. § 824o(a)(2)–(3); 18 C.F.R. §§ 39.2(b) and 40.2; *see also* NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, RELIABILITY STANDARDS FOR THE BULK ELECTRIC SYSTEMS OF NORTH AMERICA (Oct. 1, 2021), https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.

[207] *See e.g.*, North American Electric Reliability Corporation, NERC Contingency Reserve, BAL-002-WECC-3, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf.

accredited generation capacity drops below the required levels, NERC can impose civil penalties on Basin Electric directly or the System Operator overseeing Basin Electric's operations, who in turn can assign the penalty responsibility to Basin Electric.[208] Basin Electric could face such penalties if it were forced to transition too quickly to renewable energy sources, which have lower value placed on their capacity contributions towards meeting reliability standards due to the intermittent nature of their fuel source. Basin Electric could also face these penalties if it is forced to shut down existing EGUs, either for good or temporarily install retrofits.

As a result of this, Basin Electric must ensure enough generating capacity on both sides of the East-West ties in order to serve its member load requirements across all four assessment areas. Basin Electric must also ensure enough capacity to meet each system's member requirements, as Basin Electric's system is subject to certain reliability standards established by FERC and NERC.[209] These reliability standards require that Basin Electric prudently employ sufficient generation capacity accreditation to meet customers' needs.[210] Basin Electric could face such penalties if it were forced to transition too quickly to renewable energy sources, which have lower value placed on their capacity contributions towards meeting reliability standards due to the intermittent nature of their fuel source. Basin Electric could also face these penalties if it is forced to shut down existing EGUs, either for retrofitting or for good.

D. EGUs Cannot Be Rapidly Replaced with Renewable Energy Sources

Nonetheless, the Proposed Rule encourages retirement of coal-fired power plants, or alternatively the installation of CCS (which requires significant generation to operate), but Basin Electric cannot meet energy demand requirements by simply replacing its coal fired EGUs with lower emitting sources. And, even if EGUs are not shuttered, CCS could affect the units' generation capacity accreditation, as discussed above.

The following chart summarizes Basin Electric's coal-fired generation capacity, as well as the capacity that may be lost if Basin Electric is required to install parasitic CCS at the facilities.[211]

Coal Units in Basin Electric's Resource Portfolio	Basin Electric or Member's Ownership/Entitlement Shares by Unit (MW)	Total Net Generating Capacity by Unit (MW)	Expected Loss of Net Generating Capacity from Additional CCS Station Service (MW)
LOS 1	220	220	55

[208] *Id.*

[209] *See* 16 U.S.C. § 824o(a)(2)–(3); 18 C.F.R. §§ 39.2(b) and 40.2; *see also* NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, RELIABILITY STANDARDS FOR THE BULK ELECTRIC SYSTEMS OF NORTH AMERICA (Oct. 1, 2021), https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.

[210] *See e.g.*, North American Electric Reliability Corporation, NERC Contingency Reserve, BAL-002-WECC-3, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf.

[211] *See* Section V.

LOS 2	440	440	110
LRS 1	92	560	140
LRS 2	313.5	570	143
LRS 3	313.5	570	143
AVS 1	450	450	113
AVS 2	450	450	113
DFS	405	405	101
Neal 4	105	650	163
Walter Scott 3	27	705	176
Walter Scott 4	45	811	203
Total Coal At Risk	2,861	5,831	1,460
SPP & MISO Total Coal Capacity (each)		~20,000+	5,000+

The loss of the coal-fired generation capacity would have real consequences in terms of meeting energy demands. Even the largest wind projects constructed by Basin Electric offer less megawatt capacity than coal- and natural gas-fired resources. For example, Units 2 and 3 of the Laramie River Station in Wyoming provide a total of 627 MW of power to the western system, while the wind projects constructed by Basin Electric range from a capacity of 2.6 MW to 172 MW.[212] These resources cannot simply be swapped out at a one-for-one MW ratio.

This is especially true as each region in which Basin Electric operates values the capacity contribution of intermittent renewable resources like wind and solar significantly lower than the capacity contribution of conventional fossil-fuel-fired resources.[213] This is because conventional resources can typically start and run whenever they are needed, while renewable resources can only generate energy when weather permits. Therefore, while conventional resources can be accredited for nearly 100% of their generating

[212] *See* BASIN ELECTRIC POWER COOPERATIVE, NORTH DAKOTA TEN YEAR PLAN, 14–17 (June 1, 2020), https://psc.nd.gov/database/documents/20-0300/001-010.pdf (submitted as "Attachment 7 – Excerpt from North Dakota Ten Year Plan").
[213] SOUTHWEST POWER POOL, 2020 ELCC WIND AND SOLAR STUDY REPORT, 1 (July 2021), https://www.spp.org/documents/65169/2020%20elcc%20wind%20and%20solar%20study%20report.pdf (submitted as "Attachment 15 - Excerpt from 2020 ELCC Wind and Solar Study Report").

capability, an intermittent renewable resource is only accredited for a fraction of its total net generating capability.[214]

For example, in the SPP region, where nearly all of Basin Electric's wind and future solar resources are located, the accredited capacity value of wind resources are currently expected to be valued at approximately 16.8% of their capability in the summer and 17.1% in the winter, and expected to only decrease in value as more wind resources are added to the region.[215] Solar resources' accredited capacity are valued at approximately 85% in the summer and 32% in the winter, with a similar expectation that their accreditation value will only decrease as more solar resources are installed in the region.[216]

As a result, fossil-fuel-fired resources cannot be directly replaced on a one-to-one basis with the same amount of net generating capability of a wind or solar resource. Depending on the applicable reliability standards, an electricity generating utility may need to replace a conventional resource with anywhere from two to ten times the amount of wind or solar generating capability. Put differently, if Basin Electric attempted to replace a 100 MW coal-fired plant with a 100 MW wind project, it could be penalized for failing to comply with applicable reliability standards because renewable resources are intermittent by nature and cannot provide the same consistency in or overall level of generation output that is required to provide safe and reliable service. Accordingly, the transition to renewable energy sources must take into account the many related capacity and reliability requirements imposed by FERC, NERC, and the System Operators.

E. EPA Is Impermissibly Regulating Power Supply Without Consulting Interested Stakeholders

EPA's Proposed Rule attempts to regulate the Nation's electric system, an area better suited for the FERC and DOE. FERC and DOE are responsible for ensuring the reliability of the Nation's electric system. Under the Federal Power Act, FERC has jurisdiction over the "transmission of electric energy in interstate commerce," and is responsible for maintaining the reliability of the electric grid.[217] Thus, while EPA is tasked with "environmental regulation," it is not tasked with "power regulation," which is statutorily reserved to FERC. However, a rule that incentivizes electricity generating utilities to shut down fossil-fuel-fired plants, requires installation of costly and not yet widely available technology, and dictates the type of fuel to be used is the very embodiment of "power regulation."

Additionally, EPA failed to engage with interested energy regulators. While the Proposed Rule states that EPA "consulted with the DOE and [FERC] in the development of these proposals,"[218], EPA failed to consult with NERC or any of the System Operators in charge of ensuring electric reliability within regional markets. FERC has certified NERC as

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[214] *Id.* at 1–3.
[215] *Id.* at 1–2.
[216] *Id.* at 2–3.
[217] 16 U.S.C. § 824(b)(1).
[218] 88 Fed. Reg. at 33,247.

the nation's "electric reliability organization," and NERC has developed enforceable standards to ensure electric grid reliability. Generation and transmission responsibilities on the Eastern and Western Interconnections are overseen by electricity grid managers or electricity balancing authorities, which include Independent System Operators or Regional Transmission Organizations that are certified by FERC. Yet EPA did not consult these entities when analyzing how the Proposed Rule will affect grid reliability.

This is despite encouragement from stakeholders to "collaborate with other agencies such as DOE, Federal Energy Regulatory Commission, Regional Transmission Organizations, and Independent System Operators."[219] Ultimately, analysis of grid reliability should be left to the entities charged with ensuring electric reliability. At the very least, EPA should have consulted with these entities so that they could provide their valuable perspective and expertise to determine the risks that the Proposed Rule poses to the electric grid.

F. EPA Fails to Analyze the Cumulative Impact of its Recent Regulations on Grid Reliability

Though EPA, in the Proposed Rule, provides an analysis of grid reliability resulting from imposition of the emissions limitations, it fails to analyze grid reliability in light of the various and substantial EGU regulations EPA has imposed over the past few years. Grid reliability should be assessed to analyze the cumulative impact of these regulations, which include:

- Regional haze: On January 30, 2014, EPA published a Final Rule: "Approval, Disapproval and promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze."[220] In 2017, Basin Electric entered into a settlement agreement with EPA which required installation of agreed-upon pollution control equipment at the Laramie River station.

- Interstate ozone transport: On May 24, 2022, EPA proposed to disapprove Wyoming's interstate ozone State Implementation Plan.[221] EPA also included Wyoming in its Proposed Federal Implementation Plan for interstate ozone,[222] but ultimately excluded Wyoming from the Final Rule.[223] EPA has deferred approving or disapproving Wyoming's interstate ozone SIP, but if EPA ultimately disapproves the SIP, then Wyoming, and thus Basin Electric, will be subject to strict emissions controls and an enhanced trading program.

[219] STAKEHOLDER OUTREACH DOCUMENT, (EPA-HQ-OAR-2023-0072-0024) 7–8.
[220] 79 Fed. Reg. 5032 (January 30, 2014).
[221] 87 Fed. Reg. 31,495 (May 24, 2022).
[222] 87 Fed. Reg. 20,036 (April 6, 2022).
[223] 88 Fed. Reg. 36,654 (June 5, 2023).

- Effluent Guidelines: On March 29, 2023, EPA promulgated a Proposed Rule strengthening wastewater discharge standards applicable to coal-fired power plants.[224]

- Mercury and Air Toxics Standards: On April 3, 2023, EPA proposed to update and strengthen the national Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units, commonly known as the Mercury and Air Toxics Standards ("MATS"). The proposed rule requires a two-thirds reduction in the emission standard for filterable particulate matter (fPM) and removes the low-emitting EGU provisions for fPM and non-mercury HAP metals. The proposed rule also tightens the emission limit for mercury for existing lignite-fired power plants by 70%, and strengthens monitoring and compliance regulations by requiring coal-fired EGUs to comply with the fPM standard using PM continuous emission monitoring systems.

- Coal Combustion Residuals Disposal Rule: In 2015, EPA promulgated a final Disposal of Coal Combustion Residuals from Electric Utilities rule,[225] which imposes a comprehensive set of requirements for the disposal of coal ash from steam electric power plants. The final rule was incorporated under the solid waste provisions, subtitle D, of the Resource Conservation and Recovery Act.

EPA did not analyze the cumulative impact of these various regulations on grid reliability, and thus, EPA ignored the reality EGUs are facing.

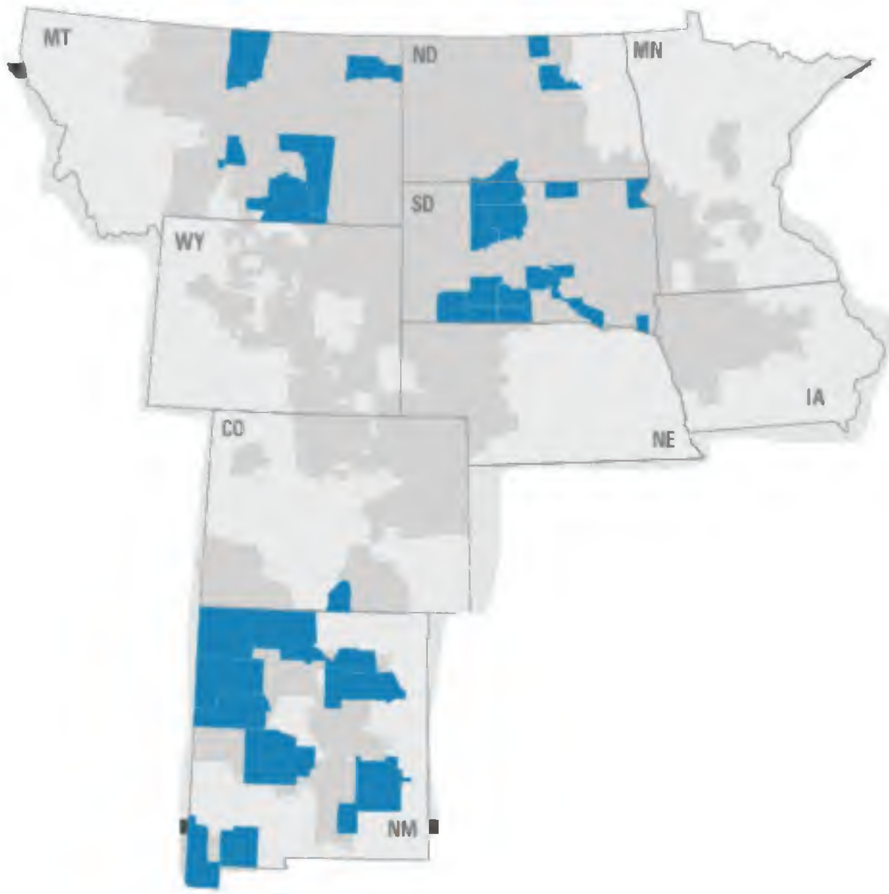
X. EPA Failed to Analyze How the Proposed Rule Will Impact Persistent Poverty and Indigenous and Native American Communities with Environmental Justice Concerns

EPA failed to analyze how grid reliability, energy production, and cost concerns will impact low-income and Native American communities throughout Basin Electric's service area. Consistent with Executive Orders 12898 and 13985, EPA must account for and consider the impact of the Proposed Rule on communities with potential environmental justice concerns. While EPA has outlined several environmental justice concerns in the Proposed Rule, it failed to analyze how grid unreliability and the availability and cost of power will impact low-income and Indigenous and Native American communities.

Basin Electric serves numerous persistent poverty counties in Montana, Colorado, New Mexico, North Dakota, and South Dakota. The United States Census defines persistent poverty counties as those counties with "maintained poverty rates of 20 percent or more

[224] *See* 88 Fed. Reg. 18,824 (March 29, 2023).
[225] 80 Fed. Reg. 21,301 (April 17, 2015).

for the past 30 years."[226] The map below displays the persistent poverty counties that Basin Electric serves:



"Research has suggested that people living in higher poverty areas experience more acute systemic problems than people in lower poverty areas."[227] These communities depend on affordable and reliable electricity. However, EPA failed to consider how grid reliability concerns impact these communities.

Basin Electric also serves numerous federally recognized Native American Tribal communities, many of which overlap with persistent poverty counties. Moreover, Executive Order 13,985 lists Indigenous individuals and Native American Tribes as an "underserved community," and the Federal Government must consider how an executive agency or department's policies and programs "perpetuate systemic barriers to opportunities and benefits for [Indigenous and Native American persons]."[228]

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[226] Craig Benson, Alemayhu Bishaw, Brian Glassman, *Persistent Poverty in Counties and Census Tracts*, CENSUS.GOV (May 9, 2023), https://www.census.gov/library/publications/2023/acs/acs-51.html.
[227] *Id.*
[228] Exec. Order No. 13,985, 86 FR 7009, 7009–10 (2021).

Tribes and Nations served by Basin Electric include Cheyenne River Sioux Tribe, Chippewa and Cree Tribes of Rocky Boy, Crow Creek Sioux Tribe, Crow Tribe, Flandreau Santee Sioux Tribe, Gros Ventre and Assiniboine Tribes of the Fort Belknap Indian Community, Assiniboine and Sioux Tribes of Fort Peck, Lower Brule Sioux Tribe, Northern Cheyenne Tribe, Oglala Sioux Tribe of Pine Ridge, Omaha Tribe of Nebraska, Rosebud Sioux Tribe, Sisseton Wahpeton Oyate Nation, Spirit Lake Nation, Standing Rock Sioux Tribe, Three Affiliated Tribes of Mandan, Hidatsa and Arikara, Turtle Mountain Band of Chippewa, Upper Sioux Community, Winnebago Tribe of Nebraska, and Yankton Sioux Tribe.

These Tribes and their members depend on Basin Electric for grid reliability and affordable energy. Nonetheless, EPA has failed to consider how concerns over grid reliability and affordable energy will impact Native American Tribal communities.

XI. EPA FAILS TO CONSIDER THE REMAINING USEFUL LIFE OF EGUS AND THE PROPOSED RULE WILL RESULT IN A TAKING

The Proposed Rule could result in unconstitutional takings. CAA Section 111 separates regulation of new sources from regulation of existing sources to protect existing investments and infrastructure. While Section 111(b) provides EPA with authority to establish standards of performance for new sources, Section 111(d) restricts EPA's authority to issuing "guidelines" to states that must then develop their own plans for regulating existing sources.[229] In developing such plans, States must give due regard to the remaining useful life of existing sources and "other factors" appropriate to protecting existing investments.[230] This reflects the intent of Congress to protect—rather than prematurely retire—existing EGUs. Indeed, the legislative history of the 1977 CAA Amendment states that "the Administrator's guidelines must take into account the remaining useful life of existing sources," and unless "the State decides to adopt and enforce more stringent standards, the State plan would be expected to take into account the remaining useful life of the source (or sources)."[231]

As discussed above, the Proposed Rule is not intended to implement achievable emissions reductions based on adequately demonstrated technologies, but rather to force the early retirement of coal-fired generation and to shift generation from coal- and natural gas-fired to hydrogen-fired electric generation. With the costs to install CCS likely to exceed the actual construction costs of the plants, the economic impact of the regulations will be significant and force many sources to reevaluate the continued operation of their facilities. If, for example, CCS is required for existing sources, most affected units will retire. Indeed, EPA's modeling reflects this reality: EPA predicts that only 1 GW of incremental coal, out of more than 200 GW of coal in service today, will pursue CCS to comply with the Proposed Rule.[232] This forced generation shifting will result in early retirements constituting a taking

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[229] 42 U.S.C. § 7411(d)(1).
[230] *Id.*
[231] H.R. Rep. No. 95-294, at 195 (1977), reprinted in Legislative History of the Clean Air Act Amendments of 1977.
[232] INTEGRATED PROPOSAL MODELING AND UPDATED BASELINE ANALYSIS (EPA-HQ-OAR-2023-0237) at 18.

of private property in contravention of the Fifth Amendment to the United States Constitution.

Additionally, EPA attempts to restrict state authority to consider the "remaining useful life and other factors" under CAA section 111(d) by defining "threshold requirements" that states must show before invoking RULOF. Essentially, EPA proposes to impose requirements on states that are not found in the text of section 111(d). In enacting that section, Congress recognized that states are best situated to address the unique characteristics of individual facilities within their state. By constraining states' discretion, EPA's Proposed Rule may result in takings of private property.

The Fifth Amendment takings clause is designed to prevent the government from "forcing some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole."[233] Takings clause violations may occur where government regulation interferes with individual property rights.[234]

While there is no set formula for analyzing a taking, courts consider three factors in determining whether a regulatory taking has occurred: (1) the economic impact of regulation on the private property owner; (2) the extent to which the regulation interferes with investment-backed expectations; and (3) the character of the government's invasion of the owner's private property interest.[235] This inquiry focuses largely "upon the magnitude of a regulation's economic impact and the degree to which it interferes with legitimate property interests."[236] Moreover, it has long been recognized that "while property may be regulated to a certain extent, if regulation goes too far it will be recognized as a taking."[237] EPA's Proposed Rule "goes too far."

The Proposed Rule's impact on Basin Electric and other sources, analyzed under the *Penn Central* factors, support a finding that the Proposed Rule will likely end in a regulatory taking. First, the Proposed Rule will have vast economic impacts on owners and operators like Basin Electric who are likely to be forced to cease operation of their coal-based facilities. With compliance costs running into the billions, the Proposed Rule will require owners and operators of coal-fired power plants to either undertake prohibitively expensive capital investments to continue operation or prematurely retire their plants. Operational reductions and premature retirements will strand substantial capital investments and produce severe and unjustifiable economic waste. Additionally, there are

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[233] *Armstrong v. United States*, 364 U.S. 40, 49 (1960); *see also Lucas v. S.C. Coastal Council*, 505 U.S. 1003, 1019 (1992) (stating that when an owner of property "has been called upon to sacrifice all economically beneficial uses in the name of the common good, that is, to leave his property economically idle, he has suffered a taking").

[234] *See, e.g., Penn. Coal Co. v. Mahon*, 260 U.S. 393, 415 (1922) (regulatory taking resulted where statute prohibiting subsidence from anthracite mining interfered with preexisting contractual mining rights); *Formanek v. United States*, 26 Cl. Ct. 332, 335 (1992) (denial of Section 404 permit application constituted a taking, largely due to the dramatic reduction in value and the government's interference with investment-backed expectations to develop property).

[235] *Penn Cent. Transp. Co. v. City cf New York*, 438 U.S. 104, 124 (1978).

[236] *Lingle v. Chevron U.S.A., Inc.*, 544 U.S. 528, 540 (2005).

[237] *Mahon*, 260 U.S. at 415.

other costs associated with the premature retirement of a facility, which the Proposed Rule does not recognize. For Basin Electric, some of these costs could include:

- Costs associated with asset retirement (solid waste disposal facilities, transmission lines, ponds and ground water monitoring);
- Depreciation impacts (shorter lives, therefore greater depreciation costs that would increase member rates);
- Potential breaches of purchase power agreements (required to fulfill member obligations);
- Potential breaches of existing coal supply contracts;
- Breaches of long-term equipment leases; and
- Long-term costs of maintaining a facility if it is no longer operational.

Second, the Proposed Rule interferes with Basin Electric's investment-backed expectations by denying use of their investments. Basin Electric has already invested a considerable amount of technology and resources to comply with EPA regulations. Specifically, Basin Electric has invested billions of dollars in facility improvements and installation of costly pollution control technology. In light of its investments, some of Basin Electric's coal assets are scheduled to remain in operation until the mid-century.

Nor could Basin Electric have anticipated that EPA would adopt regulations making its existing investment uneconomical, thereby requiring retirement of facilities. An inquiry into whether a private property owner's investment-backed expectations are reasonable considers whether the party operates in a highly regulated industry, whether it was aware of the problem requiring regulation at the time it purchased the property, and whether it could have reasonably anticipated the possibility of such regulation in light of the regulatory environment at the time of purchase.[238] While the coal combustion industry is highly regulated, at the time Basin Electric acquired most of its coal units it could not have anticipated the approach being taken here by EPA. Accordingly, Basin Electric's investment-backed expectations to operate its facilities for the remaining useful life of the source are reasonable.

Third, the character of the Proposed Rule does not justify the imposition on private property owners like Basin Electric.[239] The Proposed Rule contravenes CAA section 111 by designating as BSER two emissions controls technologies that have not been adequately demonstrated. Because of the impracticability and infeasibility of these emissions control technologies, the Proposed Rule will likely result in the shutdown of many coal-based generating units. The Proposed Rule also has minimal carbon impact; its effect is to reduce carbon emissions by 4.6 million metric tons by 2035 while a typical coal generator emits 3.5 million metric tons *per year*. Regardless of the purported climate benefits attributable

[238] *Appolo Fuels, Inc. v. United States*, 381 F.3d 1338, 1349 (Fed. Cir. 2004).
[239] *See Palazzo v. Rhode Island*, 533 U.S. 606, 634 (2001) ("The purposes served, as well as the effects produced, by a particular regulation inform the takings analysis.").

to the Proposed Rule, on balance, the burden placed on electricity generators like Basin Electric is too great to justify any benefit served. Therefore, the Proposed Rule is likely to result in unconstitutional takings, and Basin Electric urges EPA to amend the Proposed Rule to provide emission standards based on adequately demonstrated BSER that will not result in early retirement of its existing coal units.

XII. CONCLUSION

Basin Electric urges EPA to withdraw its Proposed Rule. EPA's extremely aggressive BSER determinations are not adequately demonstrated and cannot support achievable emissions limitations. Additionally, EPA does not have statutory authority to require early retirements of EGUs under the guise of emissions limitations and guidelines. EPA's Proposed Rule is unworkable, impossible to implement in the timeframe proposed, and will put the Nation's electric grid at risk.

Appendix 16

THE BUCKEYE INSTITUTE

Comment on EPA's Proposed Rule for New and Existing Fossil Fuel-Fired Power Plants

Public Comment
EPA-HQ-OAR-2023-0072-0001
Published in 88 FR 33240

The Buckeye Institute
Caesar Rodney Institute
Frontier Institute
John Locke Foundation
Mackinac Center for Public Policy

August 8, 2023

Abbreviation Definitions

BSER – Best System of Emission Reduction
CAA –Clean Air Act
CCS – Carbon Capture and Sequestration
CO_2 – Carbon Dioxide
DOE –Department of Energy
EGU – Electricity Generating Unit
EOR –Enhanced Oil RecoveryEPA – United States Environmental Protection AgencyMT – Metric Tonnes
MW – Megawatt
MWe – Megawatt-equivalent
NETL – National Energy Technology Laboratory
SaskPower – Saskatchewan Power Corporation
SCC –Social Cost of Carbon
WAG – Water-Alternating-Gas

Glossary

Capture rate –the rate at which a CCS plant can remove CO_2 from treated flue gas. Capture rate does not equate to total emissions from a plant.

CO_2-EOR – an Enhanced Oil Recovery method whereby CO_2 is injected into a mature well, typically using a WAG process, to recover 30-70 percent of the residual oil stored in an oil formation's small rock cavities.

Enhanced Oil Recovery (EOR) – a series of methods and used to extend the productive life of a mature oil field, typically by injecting gases, such as ethane, nitrogen, and CO_2, into a well in a WAG configuration.

Flue gas – the emissions from a coal or natural gas fired EGU.

Treated Flue Gas – the amount of flue gas subjected to treatment by a CCS, rated in MWe.

Introduction

There are many flaws with the Environmental Protection Agency's (EPA) proposed rule for limiting emissions from sources of greenhouse gas. Chief among them is the EPA's recommendation of carbon capture and sequestration (CCS) systems as the best systems of emission reduction (BSER) for coal-fired electricity generating units (EGUs) that intend to operate beyond 2039. In more than two decades, no government funded CCS pilot program or commercial-scale facility has adequately demonstrated the BSER. This means that the EPA's BSER is not viable and therefore cannot be a "best" system of emission reduction. Concerningly, forcing compliance with EPA's BSERs will likely exacerbate an impending energy security and reliability crisis by dissuading utilities from investing in reliable baseload sources of electric power, and pigeon-holing them to adopt intermittent—and consequently unreliable—renewable power sources.

The EPA's proposal to adopt CCS as a BSER, and its standard for states to meet based on CCS, are arbitrary, capricious, and an abuse of discretion. The EPA justifies its standard by providing examples of CCS facilities that do not meet the agency's proposed standard. The sources for the EPA's examples do not demonstrate what the EPA claims. Further, the EPA ignores important aspects of implementing CCS systems.

Despite ample evidence proving CCS has never met the Clean Air Act's (CAA) criteria for "adequate demonstration" of a BSER, the EPA is not offering any other BSER for existing coal-fired-EGUs "other than CCS with 90 percent capture."[1]

The EPA has presented CCS as a burgeoning, cost-effective, and fully functional technology capable of mitigating the majority of all coal-fired power plants' emissions. But no existing CCS plant has managed to achieve the proposed BSER's required 88.4 percent reduction in total carbon dioxide (CO_2) emission via a 90 percent CO_2 capture rate from a full CCS system – which the EPA's BSER would functionally require. And the EPA misreported, misrepresented, and misinterpreted its primary examples of commercial CCS facilities attaining a 90 percent capture rate.[2] Although every plant demonstrated the ability to capture CO_2 from flue gas emissions, every plant failed to achieve the minimum emissions reduction target that the EPA set for the proposed BSER. No CCS facility has demonstrated a consistent ability to sequester 90 percent of total greenhouse gas emissions.

Figure 1 shows the EPA's view—or at least hope—of CCS's current technological capability based on a hypothetical CCS process designs presented in a National Energy Technology Lab (NETL) report.[3] Figure 2 shows the actual capture rate and total emissions mitigation achieved by SaskPower's Boundary Dam Unit 3's CCS facility in 2022. The EPA cites the SaskPower Boundary Dam as the best-case example of current CCS technology. SaskPower's demonstrated capture rate

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[1] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.
[2] *Ibid.*
[3] Tommy Schmitt et al., **Cost and Perforamnce Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.

is far below what the EPA has claimed, and well below the BSER's proposed 88.4 percent emission reduction.

Figure 1: EPA REQUIRED EMISSION REDUCTION PLAN

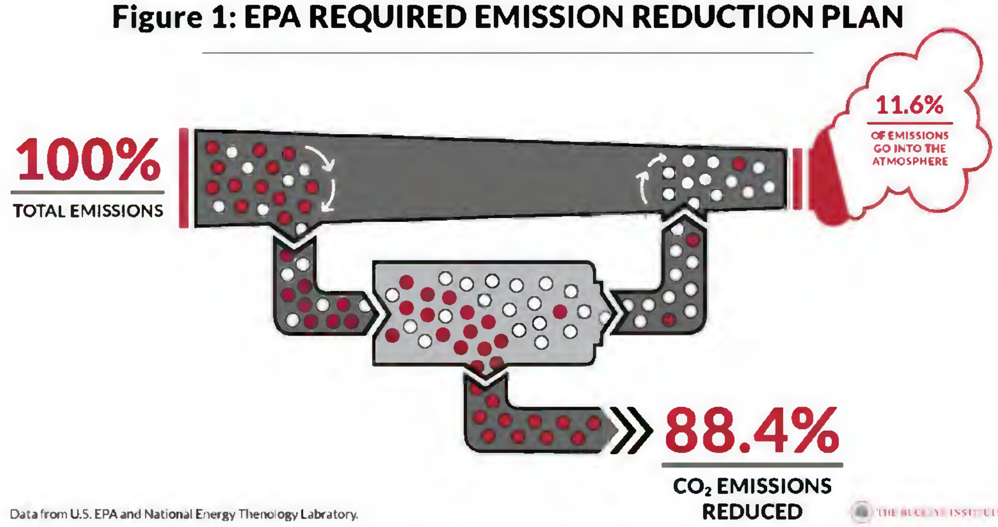
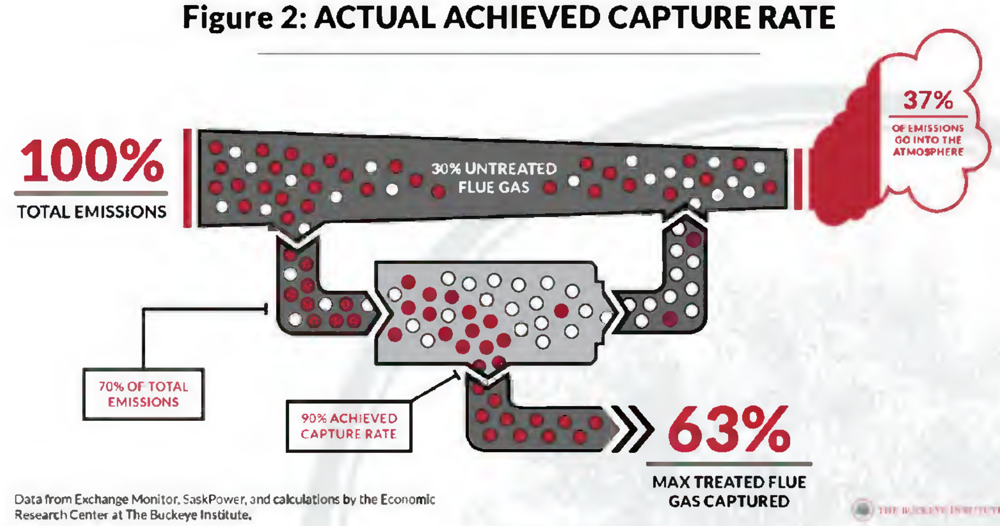


Figure 2: ACTUAL ACHIEVED CAPTURE RATE



The EPA's arbitrary standard does not reflect what CCS has achieved or is scientifically capable of achieving. Yet, the EPA will require all existing long-term coal fired EGUs to implement these costly retrofits.

Additionally, the EPA has also set a BSER for existing natural gas and oil fired EGUs. These new emission rate caps placed on baseload EGUs threaten to worsen grid reliability and trigger an energy security crisis in America. Last year, Americans saw electricity rates increase 15.8 percent, the greatest year-over-year rate increase in two decades.[4] The EPA's proposed restrictions on coal and natural gas fired power plants that provide over 80 percent of America's electric power, present a problem for meeting increased power demand. Utilities will be dissuaded from investing in baseload sources of power dependent on fossil fuels and pigeonholed into using intermittent sources of renewable power to meet America's ever-growing energy needs.

The EPA's Regulatory Impact Analysis failed to adhere to defensible and sound procedures for quantifying costs and benefits. Instead, the agency cherry-picked a range of real discount rates for use in unreliable integrated planning models when calculating the social cost of carbon (SCC) and estimating compliance costs. By discounting the SCC at 2.5, 3, and 5 percent at the 95th percentile of climate damage estimates, the EPA failed to adhere to OMB Circular A-4's guidelines for discounting by omitting the prescribed real discount rate of seven percent. Similarly, the EPA did not discount the national electricity sector's compliance costs at Circular A-4's required discount rates of three and seven percent. Instead, the EPA selected a single discount rate—3.76 percent—to estimate compliance costs in its integrated planning model. By using lower discount rates to estimate the social cost of carbon and the compliance costs, the EPA vastly overstates the benefits of the new regulations while severely understating compliance costs.

In its current form, the proposed rule will jeopardize America's energy security by making cheap power scarce and markedly increasing power costs for all Americans, rich and poor alike. America's poor and minority communities, however, will be the most impacted by higher utility rates, which are tantamount to a regressive tax.

I. The EPA's Proposed BSER.

The EPA's proposed rule requires all existing coal plants to comply with the standards based on the agency's established BSER. The BSER instructs all existing coal plants to retrofit their EGUs with CCS technologies with a minimum capture rate of 90 percent or reduce total CO_2 emissions by 2030—a mere seven years from now. Coal plants that do not—or cannot—comply with the proposed rule's BSER will be required to implement 40 percent natural gas co-firing and submit a plan to shut down coal-fired generating units by 2032.[5] Based on a NETL report, the EPA asserts that a 90 percent capture rate will result in an overall reduction of coal plant emissions by 88.4 percent. The EPA has set 88.4 percent emission reduction as the minimum emission reduction target and has provided CCS as the only "demonstrated" technology capable of meeting this target.

All CCS facilities cited by EPA used an amine-based solution to absorb CO_2 from flue gas emissions. The process for capturing CO_2 from flue gas is energy intensive, consuming more energy than what an EGU can produce. Ali et al. (2023) states that "the current energy penalty level of CO_2 chemisorption is still unbearable if a full-scale CO_2 removal process is to be

[4] U.S. Bureau of Labor Statistics, **12-month percentage change, Consumer Price Index, selected categories – Electricity**, (Last visited June 27, 2023).
[5] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

implemented for... coal-fired power plant[s]."[6] CCS plants use most of their energy to compress flue gas and heat treating the amine-solution to release the trapped CO_2.[7]

CCS facilities consume a lot of power to scrub CO_2 from flue gas. The electric power used in the processes can either be drawn directly from the attached coal-fired EGU or produced by an ancillary generator. When the CCS facility is integrated with the EGU, it results in a parasitic load that reduces overall power output,[8] which can raise electricity rates for consumers in the region near the coal-fired EGU. The immense energy inputs required to sequester CO_2 at a large-scale makes it physically impossible for a CCS facility integrated into an EGU to attain and sustain a 90 percent capture rate without consuming more energy across the CO_2 sequestration lifecycle than is produced by the coal fired-EGU. Non-integrated CCS facilities will need to draw from a reliable and dispatchable power source, *e.g.*, natural gas, nuclear, or coal fired power.

The EPA cited three coal fired facilities utilizing CCS as primary evidence for the BSER. None of the cited CCS facilities, however, achieved a consistent 90 percent capture rate on a significant portion of the emissions covered by the regulation. No commercial CCS facility has successfully met the EPA's requirement to reduce total emissions by 88.4 or continuously sustain a 90 percent capture rate over a long-term period.

II. The Proposed Rule's Technical Problems.

The proposed rule's defects begin with misquoted sources and extend to inconsistent standards and irrelevant concepts that confuse and mislead.

a. Incorrect Citations and Misquotations.

As evidence to establish the BSER, the EPA stated that SaskPower's Boundary Dam Unit 3's CCS facility demonstrated the "commercial-scale... of solvent-based post-combustion CO_2 capture systems at power generation facilities (specifically PC plants) [and] has shown the ability to capture 90 percent of the CO_2 in the flue gas stream."[9] The proposed rule's justification for this assertion—the 2022 NETL report—never stated that the plant achieved a 90 percent rate of capture.[10] A single data point taken from Figure 7 in Giannaris' report implies that a 90 percent capture rate of Unit 3's total emissions was achieved once in 2015 for a single day. The remaining data in the time series shows that Boundary Dam has never sustained a 90 percent capture rate.[11] The proposed rule also cites the 2022 NETL report to provide the 88.4 percent emission reduction

[6] Emad Ali, Mohamed K. Hadj-Kali, Salim Mokraoui, Rawaiz Khan, Meshal Aldawsari, Mourad Boumaza. "**Exergy analysis of a conceptual CO_2 capture process with an amine-based DES**," *Green Processing and Synthesis* Volume 12, Issue 1, February 16, 2023.

[7] Tom Yelland, **The Role of Solvents in Carbon Capture**, CarbonClean.com, August 17, 2021.

[8] **CO_2 Capture Technologies, Post Combustion Capture (PCC)**, Global CCS Institute, January 2012.

[9] Tommy Schmitt et al., **Cost and Perforamnce Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.

[10] Stavroula Giannaris et al., **SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability**, 15th International Conference on Greenhouse Gas Control Technologies, March 2021.

[11] *Ibid.*

standard. But the NETL report misrepresented Giannaris' report when citing it as a justification for the following claim: "Commercial-scale demonstration of solvent-based post-combustion CO2 capture systems at power generation facilities... has shown the ability to capture 90 percent of the CO2 in the flue gas stream."[12] SaskPower's Boundary Dam Unit 3 was only able to achieve a 90 percent capture rate by reducing the intake of untreated flue gas. Reducing the plant's flue gas intake resulted in a de-rating of the CCS plant's effective target to a maximum capture rate of 65 percent of total emissions, which the plant has yet to demonstrate.[13] The EPA has failed to accurately cite a scientific study as primary evidence for its BSER and must therefore change its standard to reflect what the scientific report stated or provide new scientific evidence that supports, clarifies, contextualizes, or qualifies the claim that Boundary Dam Unit 3 achieved its targeted capture rate.

b. Inconsistent Baseline for Reporting Reduction in Carbon Capture.

One of E.O. 12866's objectives is to make the regulatory review process "more accessible and open to the public."[14] Undermining this objective, the metric Megawatt equivalent (MWe) is a confusing metric and a poor choice for rating a CCS system's CO2 capture capabilities. Unaccompanied by an EGU's generation capacity, fuel type, and total daily emissions, MWe is a useless measure of CCS capture that has been misunderstood and inconsistently reported. Indeed, even the EPA has shown its misunderstanding by its inconsistent use of MWe throughout the proposed rule. Without a quantitative metric, it is impossible to measure the efficacy of CCS.

A watt is a unit[15] equal to 1 Joule per second and used to measure instantaneous power. A watt hour (Wh) is the measure of continuous electrical energy needed to power a device. Typically, lightbulbs and small household appliances have energy requirements rated in watt hours. A Megawatt (MW) is a million watts and represents power equal to 1,000,000 Joules per second. Because power plants generate a lot of electric power, their capacity is typically given in Megawatts. Unlike MW, Megawatt-equivalent (MWe) is not a unit that measures the rate of energy flow per unit of time. Instead, MWe can have many different meanings depending on the context.

In America, CCS facilities use MWe to qualitatively describe their nameplate capture capacity. Every MW generated at a coal-fired power plant releases a quantity of emissions. MWe measures the emissions released by the coal plant per MW produced. For example, A CCS facility rated at one MWe captures the emissions released by the coal plant per one MW of power generated.

MWe is a poor metric for several reasons. First, MWe can easily be confused with MW. MW measures power generated. Worse yet, megawatt electric, which measures the electric power produced by a boiler, uses the same abbreviation, MWe, to differentiate electric MW and MW

[12] Tommy Schmitt et al., **Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.
[13] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.
[14] E.O. 12866
[15] **What is a Megawatt**, Nuclear Regulatory Commission (Last visited June 29, 2023).

thermal generated by the heat engine.[16] Consequently, MWe can be and has been interpreted as a unit for measuring a CCS plant's power consumption and total emissions mitigated. Second, CCS facilities rated in MWe only describe emissions captured at the coal plants they are attached to and are not a uniform method of emission reduction. Coal plants do not uniformly emit CO_2. Emissions can vary drastically between coal-fired power plants depending on the type of coal used, the efficiency of the boiler, turbine, and the cooling process. Thus, a 25 MWe CCS facility at one coal plant may be less effective at a different coal plant, making it an inconsistent metric for rating a CCS facility's capture rate. Third, MWe on its own does not convey information about total generation capacity or the operational schedule of the coal plant, which determines emission intensity and is an important detail for measuring effectiveness of the CCS facility. Without the coal plant's generation capacity or active capacity, MWe does not convey any information about the measured capture rate. Using MWe to represent capture capacity overstates the measured capture rate of most plants. Most CCS facilities target a 90 percent capture rate from a stream of flue gas. At a 25 MWe CCS facility, the plant only offsets 22.5 MWe of emissions. MWe's shortcomings make it an unhelpful and inconsistent metric for comparisons between CCS systems.

Due to the similarities to MW and inconsistent reporting, MWe is also a confusing metric for those unfamiliar with the terminology of CCS plants. MWe can be interpreted as any one of the following: the power rating of the CCS plant, the thermal energy in the waste flue gas stream, the parasitic load of an integrated CCS plant, or as the emissions mitigated per MW of power. These varied interpretations inevitably cause misunderstandings and distort or omit important information about the CCS facility.

Even when used and understood correctly, MWe says nothing about the CCS facility's actual achieved CO_2 capture rate or the percentage of total emissions mitigated from the coal plant. Reporting a CCS facility's maximum capture potential in MWe without the generation capacity of the EGU it is attached to, as the EPA did at Petra Nova and Plant Barry, is misleading and ultimately says nothing about the total emissions captured by the plant.

The EPA inconsistently used MWe throughout the proposed rule when describing the capture rate of several CCS facilities. The EPA described Petra Nova as a "240 MW-equivalent capture facility," and Plant Barry as a "25-MW CCS project." But subsequent scientific studies conducted by Mitsubishi (the patent holder of the KM-CDR™ process used at both plants) consistently use MWe as a rate for capture capacity.[17] Although the EPA correctly reported Petra Nova's capture capacity in MWe, it incorrectly reported Plant Barry's 25 MWe as a 25 MW capture facility. This error can be interpreted several ways: Plant Berry draws a parasitic load of 25 MW or Plant Barry is capable of mitigating 25 MWe of emissions from a flue gas slipstream. The EPA then

[16] **Megawatts electric**, Energy Education, University of Calgary (Last visited: July 18, 2023).
[17] Osamu Miyamoto, Cole Maas, Tatsuya Tsujiuchi, Masayuki Inui, Takuya Hirata, Hiroshi, Tanaka, Takahito Yonekawa, and Takashi Kamijo, **KM CDR Process™ Project Update and the New Novel Solvent Development**, Energy Procedia, November 18, 2016 ; Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.

indiscriminately switches between MWe and MW when describing capture capacity of several proposed CCS projects.

To prevent future confusion and to determine if CCS is a viable technology, the EPA should consider adopting a metric other than MWe. The new metric should be easily understandable, reportable, and comparable to total emissions and better assess the performance of the CCS facility. For example, The Saskatchewan Power Corporation (SaskPower) uses daily CO_2 capture in metric tonnes (MT) as a reporting metric for their captured CO_2 emissions. Average daily CO_2 capture rate offers several benefits over MWe. First, average daily CO_2 capture can be easily understood when reported by itself. Second, average daily capture presents a clear picture of the total emissions captured by the CCS plant on a daily basis. This number can trivially be divided by total plant emissions to assess the day-to-day performance of the plant. Third, daily capture rate creates a continuous stream of emissions data that can easily be aggregated and audited by the public to assess the performance of the CCS facility month-to-month, quarter-to-quarter, or year-to-year. Average daily capture rate simplifies the reporting of CO_2 captured by a CCS plant and makes it easier to assess the performance of a CCS facility.

Several NETL reports have used pounds of CO_2 per megawatt hour (lb/MWH) to measure CCS efficacy.[18] But although it is a superior metric to MWe, MW/ton of CO_2 can vary from site to site depending on fuel type and efficiency of the CCS plant.

The EPA needs to consistently report the capture capacity of the CCS facilities used to justify its BSER and adopt a more transparent metric that adequately describes a CCS facility's actual performance rather than its projected emission mitigation capacity, which, as will be demonstrated, has rarely been consistently achieved.

III. The Proposed Rule is Arbitrary, Capricious, and an Abuse of Discretion.

The laws of physics always trump the laws of man. The proposed rule demands the opposite.

Under the Administrative Procedure Act, agency action, findings, and conclusions must be held unlawful and set aside if found to be arbitrary, capricious, an abuse of discretion, contrary to constitutional power, or otherwise not in accordance with law.[19] Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors that Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.[20] Additionally, the agency must "examine the relevant data and articulate a satisfactory explanation for its action

[18] **Eliminating the Derate of Carbon Capture Retrofits**, National Energy Technology Laboratory, May 31, 2016; Tommy Schmitt et al., **Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.
[19] 5 U.S.C § 706(2).
[20] *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins.*, 463 U.S. 29, 30 (1983).

including a rational connection between the facts found and the choice made."[21] And as part of the required analysis for determining the BSER, the EPA must consider only viable technologies.[22]

Instead of following these prescribed norms, the proposed rule has not considered important aspects of the problem, it has not fairly examined the relevant data, has determined that an unproven—even speculative—technology is the "best system" for emissions reduction, and has based its Section 111(d) standard on the unproven technology's theorized emissions reductions. These theoretical emissions reductions cannot be achieved by the state plans in any way other than attempting to use the unproven technologies or shutting down plants entirely.

a. The Proposed Rule's CSS Examples Violate the CAA § 111(a)(1) Criteria.

i. Plant Barry

Prior to 2011, the Southern Company partnered with Mitsubishi Heavy Industries to attach a small 25 MWe CCS pilot facility to the James M. Barry Electric Generating Plant's (Plant Barry) Unit 5, a 770 MW capacity coal fired EGU in Alabama.[23] Plant Barry's auxiliary CCS plant commenced operation in 2011, and had a maximum capture capacity of a mere 550 MT of CO_2 per day, enough to offset just three percent of Unit 5's total CO_2 emissions.[24] Plant Barry's CCS plant was the only CCS facility cited by the EPA that consistently achieved and sustained a stable capture rate of 90 percent, but it showed that very small-scale CCS was possible.[25] This limited success did not demonstrate, however, that it was possible to achieve the EPA's 88.4 percent emissions reduction target. And given the small size of Plant Barry's CCS facility, it is certainly not representative of large-scale CCS facilities capabilities.

ii. SaskPower's Boundary Dam Unit 3 CCS Facility

The EPA cites SaskPower's Boundary Dam Unit 3's CCS facility as a successful demonstration of meeting the BSER's 90 percent capture rate and overall 88.4 percent emissions reduction target.[26] But that claim is factually inaccurate.

The CCS facility attached to SaskPower's Boundary Dam Unit 3 entered service in October 2014. After eight years of operation, the CCS facility has failed to consistently achieve its maximum designed capture rate. Mechanical and equipment failures stemming from design oversights forced the plant to reduce its operation capacity. The plant's annual capture rate is below 60

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[21] *Id.* at 43.

[22] *See* 42 U.S.C. § 7411 (requiring BSER to be "adequately demonstrated").

[23] **Carbon Capture and Sequestration (CCS) Demonstration Project**, Southern Company, (PowerPoint presentation, August 21, 2009); Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO_2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.

[24] **MHI Carbon Capture Technology to be Demonstrated in United States on Southern Company Coal-Fired Power Plant**, Mitsubishi Heavy Industries press release, May 22, 2009.

[25] Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO_2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.

[26] U.S. EPA, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

percent, evidence that the CCS technology cannot meet the EPA's desired standards and so cannot be the BSER.

Between 2008 and 2014, Unit 3's generation capacity was upgraded from 139 MW to 160 MW and retrofitted with a CCS facility. The CCS facility would draw a parasitic load of 50 MW of power directly from Unit 3. The CCS facility's 50MW load reduced Unit 3's power generation capacity by 31 percent from 160 MW to 110 MW of net generation capacity.[27] The CCS facility's parasitic draw negated the additional 21 MW gained by upgrading Unit 3's generation capacity, and further reduced Unit 3's power output by an additional 29 MW, which is enough energy to continuously meet power demand for 21,750 homes.[28] By integrating the CCS facility directly into Unit 3, SaskPower reduced the amount of electricity to the grid, which doubled the wholesale power price.[29]

Unit 3's CCS plant was designed as a "full" CCS system[30] to treat 100 percent of Unit 3's flue gas emissions for 90 percent of CO_2. The projected daily capture was 3,200 MT of CO_2 out of Unit 3's estimated daily emissions of 3,600 MT of CO_2.[31] Unit 3's CCS facility, however, only achieved its targeted 90 percent capture rate for several days in 2015 and never sustained it over a long period of time.

Attempts to run the CCS system at its designed capture rate of 90 percent over total emissions caused frequent equipment failures. Though intended to treat 100 percent of flue gas emissions, designers failed to account for fly ash from the coal plant entering the system and choking the SO_2 and CO_2 absorbers.[32] The fly ash contaminated and compromised the "health" of the amine solution, which severely impeded the rate of CO_2 capture.[33] Repairing and cleaning the equipment required multiple months-long outages. Additional equipment failures, such as the repeated failures in the facility's CO_2 compressor motor, also resulted in long downtime.[34]

[27] J.E. Cichanowicz, "**2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation**," (January 2022); Wesley Peck, John A. Hamling, Neil Wildgust, Charles D. Gorecki, **What Parasitic Load? a New Paradigm for Ccus**, *2019 Carbon Management Technology Conference*, July 18, 2019; Abby L. Harvey, **Two Years of Operation at Boundary Dam**, Exchange Monitor: presented at Carbon, Capture, Utilization & Storage Conference, 2016 (Last visited June 26, 2023).
[28] **Understanding electricity**, California Independent System Operator (Last visited June 26, 2023).
[29] Stefani Langenegger, **Sask. Carbon capture plant doubles the price of power**, CBC News, June 17, 2016.
[30] U.S. EPA, **Basis for Denial of Petitions to Reconsider the CAA Section 111(b) Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Generating Units**, April 2016.
[31] **SaskPower Boundary Dam 3 Project Update & Some Lessons Learned**, Cansolv Technologies Inc., March 2013; Abby L. Harvey, **Two Years of Operation at Boundary Dam**, Exchange Monitor: presented at Carbon, Capture, Utilization & Storage Conference, 2016 (Last visited June 26, 2023).
[32] Brent Jacobs et al., "**Reducing the CO2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities**," 16th International Conference on Greenhouse Gas Control Technologies (November 2022).
[33] J.E. Cichanowicz, "**2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation**," (January 2022).
[34] Carlos Anchondo, **CCS 'red flag?' World's sole coal project hits snag**, E&E News, January 10, 2022.

To mitigate equipment failures, Unit 3's CCS plant's flue gas intake needed to be downgraded from a "full" CCS system. The intake of flue gas was reduced to 70 percent of the CCS plant's designed intake capacity. Only after Unit 3's CCS facility was de-rated did the CCS facility achieve a capture rate of 90 percent CO2—but only of the 70 percent of the CO2 emissions.[35] Capture of 90 percent rate of the 70 percent of emissions reduced the CCS plant's maximum capture rate to about 65 percent of total emissions.[36] But even at the lower capture rate, the CCS facility still underperforms targets, mitigating only 57 percent of total emissions in 2021. The derating and continued under-performance of the CCS plant caused SaskPower to miss emission reduction targets.[37]

According to SaskPower, Unit 3's CCS facility was only able to capture 749,035 MT out of a designed annual capture capacity of 1,100,000 MT.[38] This puts the CCS facility's capture rate at 74 percent, well below the 90 percent of treated flue gas that the EPA claims. Out of the estimated 1,314,000 MT of CO2 emitted from Unit 3, the CCS facility was only able to capture 57 percent of total emissions (see Figure 2), well below the proposed 88.4 percent requirement.

October 2022 marked the plant's eighth year of operation. Over those eight years, the plant has only captured five million tonnes of CO2, three million tonnes short of its intended mark. Unit 3's real capture rate has been 62.5 percent of its designed capacity over its operational life[39] and has not demonstrated a satisfactory carbon capture sequestration rate to justify the EPA's proposed BSER.

iii. Petra Nova

In May 2010, NRG Energy Inc. (NRG) entered a cooperative agreement with the Department of Energy to build Petra Nova,[40] a CCS facility that would be retrofitted onto Washington A. Parish Electric Generating Station's Unit 8. Unit 8 is a lignite-fired coal boiler with a generation capacity

[35] Brent Jacobs et al., "**Reducing the CO2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities**," 16th International Conference on Greenhouse Gas Control Technologies (November 2022).
[36] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.
[37] **SaskPower Annual Report 2021-2022**, SaskPower, March 31, 2022; Karin Rives, **Only still-operating carbon capture project battled technical issues in 2021**, S&P Global Market Intelligence, January 6, 2022.
[38] **BD3 Status Update: Q4 2022**, SaskPower.com, January 23, 2023.
[39] **Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 26, 2023).
[40] **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

of 654 MW.[41] Petra Nova was designed to capture 90 percent of emissions sourced from a 240 MWe flue gas slip stream diverted from Unit 8.[42]

Using the Mitsubishi's KM-CDR™ process piloted at Plant Barry, Petra Nova was initially designed as a 60 MWe capture plant.[43] But plans to monetize captured CO2 by selling it to on-going CO2-EOR operations in the West Ranch Oil Field required larger economies of scale.[44] If Petra Nova was going to be commercially viable, the plant would need to be scaled up to 240 MWe, a factor of 4x the original design and well above Plant Barry's capture quantity.

When operating at full capacity, Petra Nova could theoretically sequester 36 percent of Unit 8's total emissions. Petra Nova's performance, however, suffered design flaws and equipment deficiencies that severely reduced its capture rate during its early years of operation. Additionally, Petra Nova was powered by a dedicated natural gas-fired turbine that emitted CO2, which effectively negated a substantial portion of the CO2 it was designed to sequester. The emissions from the natural gas turbine offset as much as 25 percent of the sequestered CO2.[45]

To prevent a parasitic load from reducing plant generation efficiency like at SaskPower's Unit 3, Petra Nova's designers did not integrate Petra Nova with Unit 8, but instead used an ancillary natural gas-fired turbine rated at 78 MW as a dedicated power source. Petra Nova drew all 35 MW of its power from the generator and sold all excess power to the grid.[46] This avoided placing a parasitic load on Unit 8 and prevented Petra Nova from removing 35 MW of electric power – enough for 26,250 homes – from the grid.[47] Ironically, Petra Nova was a CCS facility completely powered by a fossil fuel EGU.[48]

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[41] **Petra Nova is one of two carbon capture and sequestration power plants in the world**, U.S. Energy Information Administration, October 31, 2017; **Plant Barry CO2 Capture Project**, Mitsubishi Heavy Industries, LTD., October 2015; **Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 26, 2023).

[42] Scott DiSavino, **Fire shuts NRG Texas coal power unit during hot spell, all personnel safe**, Reuters, May 09, 2022; **Petra Nova Parish Holdings: W.A. Parish Post-Combustion CO2 Capture and Sequestration Project**, NETL.DOE.gov (Last visited June 26, 2023).

[43] Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020.

[44] *Ibid.*

[45] Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020; **Petra Nova Is One of Two Carbon Capture and Sequestration Power Plants in the World**, U.S. Energy Information Administration, October 31, 2017; Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

[46] Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020.

[47] **Understanding electricity**, California Independent System Operator (Last visited June 26, 2023); Osamu Miyamoto, Cole Maas, Tatsuya Tsujiuchi, Masayuki Inui, Takuya Hirata, Hiroshi Tanaka, Takahito Yonekawa, and Takashi Kamijo, ***KM CDR Process™ Project Update and the New Novel Solvent Development***, Energy Procedia, November 14-18, 2016.

[48] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

Petra Nova's target capture rate was 1.4 million MT out of a possible 1.6 million MT of CO_2 per year, roughly 40 percent of Unit 8's total emissions.[49] Operating at the targeted capacity factor of 85 percent, Petra Nova was rated to sequester 5,200 MT of CO_2 per day.[50] Like SaskPower's Unit 3 CCS facility, however, Petra Nova encountered operational challenges and frequent equipment breakdowns.[51] Houston's high summer temperatures complicated the plant's water cooling process, which hurt the CCS facility's performance. Operating the plant at full capacity during the summer stressed the system and risked equipment failures to meet the area's surging power demand for air conditioning.[52] Petra Nova also suffered from non-weather-related equipment failures, including leaks from heat exchangers and calcification, which caused its flue gas blower to vibrate.[53] Technical problems ultimately led to 367 days of outages, nearly a third of Petra Nova's operational life.[54]

The proposed rule states that Petra Nova, "successfully captured 92.4 percent of the CO_2 from the slip stream of flue gas processed with 99.08 percent of the captured CO_2 sequestered by EOR."[55] But Petra Nova never achieved its maximum capture rate, and according to a report from the Institute for Energy Economics and Financial analysis, "Emission data for Parish Unit 8 reported to the EPA suggests the actual CO_2 capture rate was substantially lower than 90%, perhaps as low as 65% to 70%. And the average capture rate does not include emissions from the gas-fired combustion turbine used to power the facility. Adding those emission lowers the overall on-site capture rate to... 55% to 58%."[56] And when considering total emissions from the W.A. Parish generating station, Petra Nova captured an even smaller percentage. In 2018, Petra Nova only captured 1.017 million MT of CO_2 out of the 14.6 million MT emitted by the entire plant—a mere six percent of total emissions.[57]

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[49] NRG Energy, **Petra Nova - WA Parish Generating Station**, nrg.com, accessed June 1, 2017; **Petra Nova, World's Largest Post-Combustion Carbon-Capture Project, Begins Commercial Operation**, Office of Fossil Energy and Carbon Management press release, January 11, 2017; **Plant Barry CO2 Capture Project**, Mitsubishi Heavy Industries, LTD., October 2015; **Petra Nova - W.A. Parish Project**, Office of Fossil Energy and Carbon Management press release, January 10, 2017.

[50] **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

[51] Valerie Volcovici and Timothy Gardner, **Biden's power plant proposal poses huge test for carbon capture**, *Reuters*, May 12, 2023.

[52] **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

[53] Oakley Shelton-Thomas, **Carbon Capture: Billions of Federal Dollars Poured Into Failure**, Food and Water Watch, September 27, 2022.

[54] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

[55] U.S. Environmental Protection Agency (EPA), **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

[56] Suzanne Mattei and David Schlissel, **The ill-fated Petra Nova CCS project: NRG Energy throws in the towel**, Institute for Energy Economic and Financial Analysis, October 05, 2022.

[57] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

Because Petra Nova was only ever designed to capture 36 percent of Unit 8's emissions at maximum capacity, and because it failed to reliably sustain a 90 percent capture rate over a long period of time, Petra Nova fails to meet the EPA's criterion of an 88.4 percent total emission reduction and does not justify CCS as a BSER.

b. CCS is Only Viable with DOE Grants and Subsidies.

The Department of Energy's (DOE) gamble on CCS technology has sent billions of taxpayer dollars chasing an elusive green dividend. Most projects that received funding from DOE in the last decade were never completed. Petra Nova was the only coal capture project that was built, but it ultimately failed to generate positive environmental benefits and cash flow. Similarly, SaskPower received 240 million CAD (US $195 million) from Canadian taxpayers.[58] But Boundary Dam Unit 3's CCS facility never profited from the commercial sale of captured CO2. In fact, CCS cost Boundary Dam millions of dollars when the CCS plant failed to deliver CO2 promised to Cenovus for Enhanced Oil Recovery. Were it not for the $50/tonne CO2 carbon tax imposed by the Canadian government, Boundary Dam's CCS plant would have been a complete failure.

Over the past decade, DOE has spent hundreds of millions of taxpayer dollars on CCS facilities. According to a Government Accountability Office (GAO) report on Carbon Capture and Storage, "DOE provided nearly $684 million to eight coal projects, [which resulted] in one operational facility"[59]—Petra Nova. However, Petra Nova ultimately shutdown due to the high cost of producing CO2 for Enhanced Oil Recovery (CO2-EOR) operations. The DOE cancelled funding agreements with four projects. The remaining $488.7 million was spread between five incipient projects that never progressed beyond paper-napkin sketches.[60]

Additionally, the GAO found that the "DOE's process for selecting coal projects and negotiating funding agreements increased the risks that DOE would fund projects unlikely to succeed."[61] The GAO concluded that the DOE's senior leadership, "did not adhere to cost controls designed to limit its financial exposure on funding agreements for coal projects... [the DOE] spent nearly $[488.7] million on the definition and design of four unbuilt facilities – almost $300 million more than planned for those projects."[62] That is a nearly 200 percent cost overrun before even starting construction.

Cost overruns at proposed CCS facilities have been well documented and devastating for utility consumers. The Kemper project was kickstarted in 2007 by Southern Power Company's

[58] **Boundary Dam Integrated Carbon Capture and Storage Demonstration Project**, Government of Canada, January 5, 2016.
[59] United States Government Accountability Office, ***Report to Congressional Committee on Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects***. Government Accountability Office, December 2021.
[60] United States Government Accountability Office, ***Report to Congressional Committee on Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects***, Government Accountability Office, December 2021.
[61] *Ibid.*
[62] *Ibid.*

subsidiary, Mississippi Power Company, which was conceived as an integrated gasification plant with an attached CCS facility capable of capturing 65 percent of total emissions from the lignite coal fuel source.[63] The DOE fed Kemper's fiscal furnace by adding $382 million in grant funding.[64] Originally, the Kemper project was estimated to cost $2.4 billion, but quickly ballooned 212.5 percent to $7 billion and ultimately was terminated. The facility was fitted for natural gas-fired generation.[65] To recover the costs of the failed project, the Mississippi state legislature authorized Southern Power to raise consumer power rates by 41 percent, roughly $37 per household per month.[66]

Congress has since rewarded the DOE's behavior with a near blank check. The Energy Act of 2020 offered the DOE $7 billion over five years (2020-2025) to examine CCS projects at natural gas-fired power plants and industrial plants.[67] The Inflation Reduction Act (IRA) has offered an additional $12 billion in funding and billions more in tax credits for yet unproven CCS facilities.[68]

Direct Air Carbon (DAC) capture is a largely unproven method of CCS. Currently, Occidental Petroleum is building the nation's first such commercial scale facility in Ector County, Texas. DAC is a yet unproven technology with high estimated CO2 capture costs. Current cost estimates for captured CO2 range well above $100 - $335 per tonne of CO2.[69] Captured CO2 will be too expensive for utilization and the cost of capture is well above the existing tax credits. Whether this facility will generate revenue remains to be seen. The project has secured a 10-year tax abatement from Ector County despite rural Texas counties depending on property tax revenue to fund education and municipal services. The loss of tax revenue from this parcel of land is an injustice that deprives a majority Hispanic community[70] of resources to fund education and local infrastructure. The EPA's BSER encourages unproven facilities like these to squander taxpayer dollars on unproven technology and prompt coal plants to try unproven DAC facilities in poor, rural counties just to mitigate emissions.

c. The Water Use Impact Analysis Underestimates Required Water Use.

Section VII.F.3.v.iii.(C) of the proposed rule cites increased water use as a potential impediment for CCS adoption. According to the EPA, CCS technology increases an EGU's combined cycle water

[63] Richard Esposito, **The Kemper Project IGCC Project Overview**, SECARB Stakeholders' Briefing, May 2010.
[64] James Conca, **The Largest Clean Coal Power Plant In America Turns To Natural Gas**, Forbes, July 11, 2017.
[65] David Schlissel, **IEEFA U.S.: Southern Company Demolishes Part of the $7.5 Billion Kemper Power Plant in Mississippi**, Institute for Energy Economics and Financial Analysis, October 14, 2021.
[66] Ian Urbina, **Piles of Dirty Secrets Behind a Model 'Clean Coal' Project**, *The New York Times*, July 5, 2016; Rebecca Smith, **Coal-Fired Power Plant Loses Steam: Mississippi utility withdraws as backer of electricity project as costs soar**, *The Wall Street Journal*, May 22, 2015.
[67] **DOE's Carbon Capture and Storage (CCS) and Carbon Removal Programs**, Congressional Research Service, April 4, 2022.
[68] Charles Harvey, Kurt House, **Every Dollar Spent on This Climate Technology Is a Waste**, MIT Civil and Environmental Engineering, August 17, 2022.
[69] International Energy Agency, **Direct Air Capture: A Key Technology for Net Zero**, 2022.
[70] U.S. Cencus, **QuickFacts: Ector County, Texas: Population Estimates**, July 1, 2022, Texas (Last Visited: July 20, 2023).

usage from 190 gallons to 290 gallons, increasing water usage over 50 percent.[71] Other sources indicate that the water requirements of carbon sequestration can double the per kilowatt water usage of a coal plant.[72] But the proposed rule asserts—with no supporting evidence—that all coal-fired EGUs can implement dry cooling to negate extra water requirements. Dry cooling, however, requires low ambient temperatures making it impractical for plants in hot or drought prone areas. Houston's Petra Nova, for example, used 1.49 billion gallons of water in addition to Unit 8's water consumption. High temperatures at the plant created problems that led to outages or the de-rating of the CCS plant.[73] If dry cooling will not work for the CCS plants, then it cannot work for power plants. Furthermore, very few EGUs rely solely on dry cooling technologies—and for good reason—but the proposed rule offers them as a unilateral solution without properly assessing how such a requirement would affect hot and drought prone regions.

d. Enhanced Oil Recovery.

Enhanced Oil Recovery (EOR) operations were a significant driver of early CCS technology. Today, proponents of CCS view CO2-EOR as a ready-made market for CO2 sourced from coal projects. Although the EPA acknowledges the important role that CO2-EOR will play in commercializing and sequestering captured CO2, the BSER stopped short of including it as a method—and rightly so. The success of a CCS project is determined by regional CO2 markets, geography, and plant-type. But in eschewing CO2-EOR, the EPA has overlooked the fact that commercial CO2 captured by coal projects is economically uncompetitive in every regional CO2 market. Due to strong competition from easily sourced natural and industrial CO2, it is unlikely that there will ever be an economic case for plants to adopt CCS voluntarily sans generous tax credits. The EPA's BSER will saddle coal plants with expensive facilities that will be unable to defray their maintained costs with the revenue stream generated by the sale of CO2 for EOR.

An oil field's productive life has three phases: primary, secondary, and tertiary recovery. Tertiary recovery can produce 30 – 60 percent of a field's original oil in place depending on the methods used and the price of oil.[74] CO2-EOR is one of several tertiary oil recovery methods used by petroleum landmen.[75] But CO2-EOR usually requires high oil prices to be economically viable. The inputs to CO2-EOR can raise the final production costs of a barrel of crude oil by $20 – $30 per barrel.[76] This makes CO2-EOR one of the most expensive methods of EOR, and uncompetitive

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[71] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

[72] Samuel K. Moore, **The Water Cost of Carbon Capture: Coal Power's Carbon Savior Could Double Its Water Woes**, IEEE.org, May 28, 2010; Rosa, L., Reimer, J.A., Went, M.S. et al. **Hydrological limits to carbon capture and storage**, *Nature Sustainability*, Volume 3 (2020) p. 658–666.

[73] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

[74] **Enhanced Oil Recovery**, Department of Energy (Last visited Jun 28, 2023)

[75] Sean T. McCoy and Edward S. Rubin, "**The Effect of high Oil prices on EOR project economics**" *Energy Procedia*, Volume 1, Issue 1 (February 2009) p. 4143 - 4150

[76] **Oil prices drive projected enhanced oil recovery using carbon dioxide**, U.S. Energy Information Administration, July 30, 2014.

with cheaper superior methods like ethane flooding.[77] Additionally, CO_2-EOR's economic viability also depends entirely on the availability and regional price of CO_2.

Over the last 70 years, geography has been, and remains, the greatest influence on determining whether manmade or naturally sourced CO_2 is used in CO_2-EOR operations. CO_2-EOR was field tested in 1964 when a CO_2 slug and carbonated water were injected into a pilot well in Mead Strawn Field.[78] After CO_2-EOR was proven feasible, high oil prices in the 1970s spurred landmen to find sources of CO_2.[79] By 1972, several industrial gas processing facilities were providing dense quantities of captured CO_2 to CO_2-EOR operations in the Permian Basin.[80] By the late 1970s, several pipeline projects were planned to tap Colorado's large deposits of natural CO_2.[81] By 1982, several of these pipelines were completed, carrying natural CO_2 to EOR projects in the Permian basin. Today, 70 to 80 percent of all CO_2 used in EOR comes from natural deposits[82] and over 90 percent of naturally sourced CO_2 is almost exclusively used in the Permian Basin.[83] The remaining 20 – 30 percent of CO_2 for EOR is nearly exclusively captured from industrial gasification plants, natural gas refineries, ethanol plants and predominantly used in the Rocky Mountains and Midcontinent regions where natural deposits of CO_2 are either difficult to access or scarce.[84] In place of natural CO_2 deposits, industrial sources of CO_2 can consistently offer dense quantities of CO_2 that are easier to capture, process, and sell to vendors. Coal CCS projects have attempted to breach into both markets and have largely failed because sourcing CO_2 in low-concentration from flue gas cannot economically compete in any region or with any other source of CO_2.

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[77] Steven T. Anderson, Steven Cahan, **Estimating market conditions for potential entry of new sources of anthropogenic CO_2 for EOR in the Permian Basin**, U.S. Geological Survey, Publications Warehouse, November 30, 2019.

[78] James P. Meyer, ***Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology***, Contek Solutions - American Petroleum Institute, November 24, 2004; Tuo Huang, Xiang Zhou, Huaijun Yang, Guangzhi Liao, Fanhua Zeng, "**CO_2 flooding strategy to enhance heavy oil recovery**" Petroleum, Volume 3, Issue 1 (March 2017) p. 68-78.

[79] Matthew Fry, Adam Schafer, et al., **Capturing and Utilizing CO_2 from Ethanol**, working paper, State CO_2-EOR Deployment Work Group, December 2017; **A Brief History of CO_2 EOR, New Developments and Reservoir Technologies for CO_2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[80] Matthew Fry, Adam Schafer, et al., **Capturing and Utilizing CO_2 from Ethanol**, working paper, State CO_2-EOR Deployment Work Group, December 2017; **A Brief History of CO_2 EOR, New Developments and Reservoir Technologies for CO_2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[81] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[82] **Enhanced Oil Recovery**, Department of Energy, energy.gov (Last visited Jun 28, 2023); **A Brief History of CO_2 EOR, New Developments and Reservoir Technologies for CO_2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; Christophe McGlade, **Can CO_2-EOR really provide carbon-negative oil?**, International Energy Agency, April 11, 2019.

[83] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999; Christophe McGlade, **Can CO_2-EOR really provide carbon-negative oil?**, International Energy Agency, April 11, 2019; Matthew Wallace, Lessly Goudarzi, Kara Callahan, Robert Wallace, "**A Review of the CO_2 Pipeline Infrastructure in the US**." *NETL*, April 21, 2015.

[84] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

SaskPower intended for Boundary Dam Unit 3's CCS facility to produce enough CO2 that captured CO2 could compete with CO2 captured from the Dakota gasification facility in North Dakota. But Boundary Dam's frequent equipment failures meant that Unit 3 was unable to meet the contractually obligated sales of CO2 to Cenovus, the operator of the Weyburn oil field.[85] By the end of 2015, SaskPower owed 12 million CAD ($9 million USD) to Cenovus for failing to deliver promised CO2 for EOR.[86] In 2016, SaskPower had to renegotiate its contract with Cenovus to avoid a $91 million (CAD) failure to deliver penalty.[87] Ultimately, Boundary Dam Unit 3 was unable to provide CO2 at the prevailing market price of $25/MT.[88] The renegotiated price resulted in Cenovus paying the market rate for CO2, while the plant's high operating costs remained the same.

Even regions that lacked access to large natural deposits and industrial sources of CO2 could not justify sourcing CO2 from coal projects for EOR operations. At Plant Barry, captured CO2 was piped 12 miles and sequestered in a geologic formation in the Citronelle Oil Field above an active CO2-EOR pilot operation.[89] Although captured CO2 from Unit 5 was not used in CO2-EOR, Plant Barry's operators planned to scale the CCS facility to capture and commercialize one MT of CO2 emissions by selling captured CO2 to CO2-EOR operations in the Citronelle oil field.[90] These plans never materialized due in part to the poor regional economics of sourcing CO2 from flue gas emissions. Petra Nova originally planned to supply enough cheap CO2 to revitalize Hilcorp's West Ranch Oil Field. But when the plant was operating, Petra Nova did not supply enough CO2 to sustain EOR operations.[91] The cost of its CO2 was estimated at $60/tonne.[92] When oil prices collapsed in 2020, operators could no longer afford to purchase Petra Nova's expensive and unreliable CO2.

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[85] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.
; ***EO 12866_GHG EGU New Sources 2060-AT56 TSD Reliability of Currently Available CCS Final Rule_20201214***, the Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, December, 2020.

[86] Fraser, D.C. **SaskPower renegotiated contract to avoid $91.8M penalty**, Regina Leader-Post, June 13, 2016;

[87] The Canadian Press. **SaskPower pays out $12M to Cenovus for not providing captured carbon dioxide**. CTV News, October 26, 2015.

[88] Geoff Leo, **Carbon Capture plant Delay Costing SaskPower Millions**, CBC News, October 26, 2015.

[89] U.S. Department of Energy, **Alabama Injection Project Aimed at Enhanced Oil Recovery, Testing Important Geologic CO2 Storage**, Office of Fossil Energy and Carbon Management, March 1, 2010.

[90] Richard A. Esposito, Jack C. Pashin, Denise J. Hills, Peter M. Walsh, "**Geologic assessment and injection design for a pilot CO2-enhanced oil recovery and sequestration demonstration in a heterogeneous oil reservoir: Citronelle Field, Alabama, USA**" *Environmental Earth Science*, Volume 60, (March 2010) p. 431-444; Konstantinos Theodorou, **Carbon Dioxide Enhanced Oil Recovery from the Citronelle Oil Field and Carbon Sequestration in the Donovan Sand, Southwest Alabama**, dissertation, the University of Alabama at Birmingham, 2013; **Plant Barry Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 23, 2023); **Southeast Regional Carbon Sequestration Partnership Citronelle Project**, NETL.DOE.gov (Last visited June 23, 2023); **Operations Initiated at Southern Company's Carbon Capture Project**, EnergyOnline.com (Last visited June 23, 2023).

[91] Florian Martin, **Low Oil Prices Lead to Shutdown of Much-Hyped Carbon Capture System Outside Houston**, Houston Public Media, August 3, 2020.

[92] Dennis Wamsted and David Schlissen, **Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant Is a Warning Sign**, Institute for Energy Economics and Financial Analysis, August 2020.

Petra Nova, Boundary Dam's Unit 3, and the cancellation of Plant Barry, are prime examples of flue gas captured CO_2's failure to deliver CO_2 at a competitive price to EOR operations. By the DOE's own estimates, the cost of capturing CO_2 from flue gas needs to decline by 50 percent.[93] Even these estimates are likely pollyannish. To spur investment in CCS technology the IRA has significantly increased the 45Q tax credit. Congress has increased the 45Q tax credit for CO_2 sequestered through CO_2-EOR by more than 70 percent, from $35/tonne to $60/tonne, to match what the DOE believes is the break-even price.[94] There is no guarantee that these tax credits will continue, but as all CCS plants have shown, without them, CCS is not economically feasible.

The EPA has proposed several methods of permanent geological sequestration that require a massive and costly build out of a CO_2 midstream infrastructure and unproven methods of geological sequestration. For example, the EPA recommends disposing of captured CO_2 by injecting it into coal seams even though it recognizes that this process remains theoretical and has not been tested.

The EPA's BSER tacitly promotes squandering financial resources pursuing the uneconomical development of CO_2 capture facilities that will never have a positive return on investment. Should Congress decide to repeal these tax credits, all CCS coal and natural gas projects will lose their only stream of reliable revenue as their captured emissions will never be able to compete with CO_2 sourced from natural deposits or industrial sources.

e. Discount Rate.

Discounting future benefit streams and compliance costs is an integral part of any benefit-cost analysis. In the net present value model, discount rates estimate the value of money received in the future by converting its value into dollars. It is important for regulators to accurately and consistently discount future benefits received and costs stemming from a regulation, so that policy makers have a complete picture.[95] In the proposed rule, the EPA properly discounted future benefits and compliance costs using the Office of Management and Budget (OMB) Circular A-4's prescribed real discount rates of 3 percent and 7 percent. But the EPA calculated the social cost of greenhouse gases (SC-GHGs) and compliance costs using much lower discount rates. These estimates were obtained using integrated planning models (IMPs) that fail to meet OMB A-4's threshold for being "sound and defensible."[96] The EPA used an IMP to calculate the social cost of carbon at five, three, and 2.5 percent at the 95th percentile of environmental damages. For calculating compliance costs, the EPA used one real discount rate of 3.76 percent.[97] The EPA's bifurcated discount rates grossly understate the private sector's compliance costs and vastly

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93 Ryser, Jeffrey. **DOE hopes to see carbon capture costs cut 50%; NETL says it has stored 10 million mt of CO_2**. S&P Global, June 10, 2020.

94 **Section 45Q Credit for Carbon Oxide Sequestration**, International Energy Agency, April 14, 2023.

95 David C. Tryon, Alex M. Certo, Zachary D. Cady, and Trevor W. Lewis, **Comment on Proposed OMB Circular A-4**, The Buckeye Institute, June 6, 2023.

96 **OMB Circular A-4**, Regulatory Analysis, September 17, 2003.

97 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... and Repeal of the Affordable Clean Energy Rule**, May 23, 2023.

overestimate the future benefits stream. This is unsurprising considering that federal agencies routinely and significantly understate the cost of their regulations.[98]

The three discount rates selected by the interagency working group (IWG) in 2010 centered around the 3 percent estimate of the consumption interest rate published in OMB's Circular A-4 in 2003. That guidance was based on the real rate of return on 10-year Treasury Securities over the prior 30 years (1973 through 2002), which averaged 3.1 percent. Over the past four decades there has been a substantial and persistent decline in real interest rates driven by decreases in the equilibrium real interest rate (Bauer and Rudebusch 2020).

OMB A-4's guidelines for regulatory analysis instruct regulators to "monetize quantitative estimates whenever possible… [by using] sound and defensible values or procedures… and ensure that key analytical assumptions are defensible."[99] The EPA and the IWG have used several integrated planning models to obtain the SC-GHGs. But the IPMs used are so inconsistent in calculating values that results are neither sound nor defensible.

Dr. Kevin Dayaratna, Chief Statistician at the Heritage Foundation, has demonstrated that the models the EPA used to estimate various SC-GH fail to produce consistent and reliable results.[100] When Dr. Dayaratna put the real discount rate of 7 percent into the IPMs, he found that the SC-GHG declines substantially and is even positive in some cases – implying that greenhouse gas emissions carry positive societal benefits. The EPA's IPM's inability to produce a consistent SC-GHG at higher discount rates implies that the models undergirding the IPMs are indefensibly inconsistent, and the derived results should be considered unsound.[101] And the EPA's inconsistent discounting treatment is not limited to estimating the SC-GHG. When discounting compliance costs of adopting CCS at fossil fuel-fired EGUs in the IPM, the EPA selected a single discount rate - 3.78 percent, well below the seven percent required by OMB A-4. Given the numerous mechanical and economic challenges encountered by Boundary Dam, Petra nova, and the Kemper Project, discounting at 3.78 percent is wholly inappropriate and vastly understates the financial risk of CCS retrofits and new fossil fuel-fired power plants. The EPA's inconsistent handling of discount rates within its own planning models should cast doubt on the empirical results presented in the benefit-cost-analysis.

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[98] Casey B. Mulligan, **Burden is Back: Comparing Regulatory Costs between Biden, Trump, and Obama**, June 2023 (estimating EPA's 2021 rule for light-duty vehicle emissions at "a cost of $309 billion, which is about 70 percent more than the EPA reported").

[99] **OMB Circular A-4**, Regulatory Analysis, September 17, 2003.

[100] Kevin Dayaratna, **Why "Social Cost of Carbon" Is the Most Useless Number You've Never Heard of**, The Heritage Foundation, March 2, 2021; Kevin Dayaratna and David Kreutzer, **Unfounded FUND: Yet Another EPA Model Not Ready for the Big Game**, Heritage Foundation, April 29, 2014; Kevin Dayaratna and David Kreutzer, **Loaded DICE: An EPA Model Not Ready for the Big Game**, November 21, 2013; Patrick J. Michaels and Kevin D. Dayaratna, **The Scientific Case for Vacating the EPA's Carbon Dioxide Endangerment Finding: The Hazard of Unreliable Models Guiding Policy**, Competitive Enterprise Institute, Issue Analysis No. 3, April 17, 2020.

[101] Kevin Dayaratna and David Kreutzer, **Unfounded FUND: Yet Another EPA Model Not Ready for the Big Game**, Heritage Foundation, April 29, 2014; Kevin Dayaratna, **Why "Social Cost of Carbon" Is the Most Useless Number You've Never Heard of**, Heritage Foundation, March 2, 2021.

f. Conclusion: The Proposed BSER for Long-Term Coal-Fired EGUs is Arbitrary, Capricious, and an Abuse of Discretion.

The EPA's proposed BSER and Section 111(d) standard fail the arbitrary, capricious, and abuse of discretion test.

First, in determining that CCS is the BSER, the proposed rule relied on the fact that forcing plants to implement CCS would advance the development of CCS technology. This is a factor "which Congress has not intended [the agency] to consider."[102] Second, the proposed rule "offered an explanation for its decision that runs counter to the evidence before" it.[103] The EPA's own sources confirm that its examples of "successful" CCS facilities have entirely failed to achieve a consistent capture rate at a level that satisfies the proposed standard. Third, the proposed rule ignores the GAO reports demonstrating the infeasibility of the CCS facilities, and thus "it ignores important considerations or relevant evidence" without justification.[104] Fourth, the proposed rule's convoluted explanation for its exemplar CCS facilities has not "reasonably considered the relevant issues and reasonably explained the decision."[105] Fifth, discounting compliance costs at 3.8 percent runs counter to evidence showing that CCS facilities do not work on a large scale.[106] All of the EPA's examples of "successful" CCS facilities had significant difficulties implementing CCS and the EPA must account for those difficulties at all other regulated plants. This implies that retrofitting existing power plants with CCS facilities puts immense financial risk on the power plant operator to comply with the regulation and warrants the use of a higher discount rate when estimating compliance costs in the IPM. Sixth, the water use impact analysis runs counter to the evidence and does not consider the additional water needed for CCS. The EPA's unilateral dry cooling solution to the extra water problem does not adequately account for hot or dry environmental constraints. Seventh, the only CCS facilities that have had even limited success were linked to CO_2-EOR operations, and the EPA's other proposed solutions of geologic sequestration, mass scale saline formation, and coal-seam injection remain theoretical. Finally, the proposed rule risks successful legal challenges because the EPA "entirely failed to consider an important aspect of the problem,"[107] namely, that CCS is only viable with DOE grants and subsidies. If Congress or the DOE eliminate these grants and subsidies, the proposed rule will shutter power plants.

Not only is the proposed rule's BSER an unproveable system, but the section 111(d) standard is based on a capture rate that has never been consistently achieved at scale. Thus, state plans must

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[102] *State Farm Mut. Auto. Ins. Co.*, 463 U.S. at 43; 42 U.S.C. § 7411 (CAA 111(a)(1)) ("the best system of emission reduction [ ] (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) . . . .").
[103] See BNSF Ry. Co. v. Fed. R.R. Admin., 62 F.4th 905, 910 (5th Cir. 2023).
[104] *Rancheria v. Jewell*, 776 F.3d 706, 714 (9th Cir. 2015)
[105] *Abbott v. Biden*, No. 22-40399, 2023 WL 3945847, at *5 (5th Cir. June 12, 2023).
[106] Genuine Parts Co. v. Env't Prot. Agency, 890 F.3d 304, 313 (D.C. Cir. 2018) ("It was arbitrary and capricious for EPA to rely on portions of studies in the record that support its position, while ignoring cross sections in those studies that do not.").
[107] *State Farm Mut. Auto. Ins.*, 463 U.S. at 30.

adopt a system that does not work or force power plants to shut down as there is no alternative to meet the standard. As the U.S. Supreme Court noted in *West Virginia v. EPA*, "[o]f course, EPA has never ordered anything remotely like that, and we doubt it could."[108]

IV. The Proposed Standard for Non-continental Gas- and Oil-fired Power Plants Risks Electricity Crises in Hawaii.

The EPA has requested comment on section XII.D.1.b.vi, non-continental intermediate and baseload oil-fired power, "that is defined by 0 to 2 standard deviations in annual emission rate (using the 5-year period of data) above the baseline emission performance, or that is 0 to 10 percent above the baseline emission performance."[109] Any regulation on non-continental oil-fired power plants will decrease dispatchable baseload power generation and substantially raise electricity rates in Hawaii, which will disproportionately impact Hawaii's poor and indigenous populations.

To avoid causing a supply and affordability crisis in Hawaii, the EPA should set no emissions limitation for non-continental oil-fired baseload and intermediate power stations. Over 80 percent of Hawaii's electric power is generated by oil-fired power plants.[110] Although Hawaii has prime geography for including some renewable power sources into its energy mix,[111] its distance from the mainland and the Merchant Marine Act of 1920 have raised the cost of building renewable energy sources and stalled the state's energy transition, leaving oil-fired power as the only reliable energy source for meeting existing and growing electric power demand for the foreseeable future.

Having a single reliable energy source puts Hawaii's grid in a precarious condition and means that even small reductions in generation capacity can raise electricity prices dramatically. In September 2020, for example, Hawaii's legislature passed Senate Bill 2629, requiring Hawaii's only coal plant on Oahu to shut down by 2022.[112] The plant complied and electricity prices immediately increased seven percent as the supply of baseload power declined and was replaced with more expensive oil-fired power plants.[113]

Hawaii has tried to fill the gap in power generation with lithium battery packs to store energy generated by the limited renewable infrastructure. But Hawaiian power companies estimate only 30 percent of the battery's energy will come from renewables, with the rest derived from oil-fired power.[114] Setting an emission limit on Hawaii's dominant source of electricity for baseload and

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[108] *W. Virginia v. EPA*, 142 S. Ct. 2587, 2612 n. 3 (2022).
[109] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.
[110] U.S. Energy Information Administration, **US Energy Atlas with Total Energy Layers** (Last Visited: Jun 26, 2023).
[111] U.S. EIA, **Hawaii Profile Analysis**, March 16, 2023.
[112] U.S. EIA, **Hawaii Profile Analysis**, March 16, 2023; **Electricity Generation; Coal; Prohibition**, 2020(Hawaii S.B. No. 2629), Act 23.
[113] Jason Lindquist, **Can't Help Falling In Love - Hawaii Finds The Move Away From Fossil Fuels Is Easier Said Than Done**, RNB energy, June 1, 2023.
[114] *Ibid*.

peak generation while the state struggles with its energy transition will condemn Hawaiians to higher electricity rates. As studies have shown, higher electricity rates are an inequitable, regressive tax that falls disproportionately hard on the poor.[115] The higher electricity prices will hurt Hawaii's indigenous community the most, 15.5 percent of whom live in poverty.[116] The proposed rule increases the cost of electricity primarily—and unjustly—on low-income and indigenous Hawaiians.

The EPA should delay indefinitely setting emission limitations on non-continental oil-fired power plants. More importantly, the EPA should learn from Hawaii's misguided decision to forcibly close its last coal-fired plant and recognize the crises that follow when regulators artificially curb coal- and gas-fired generators.

V. The Proposed Standard for Baseload Natural Gas Plants Will Exacerbate an Electricity Crisis.

The EPA's proposed "BSER of routine methods of operation and maintenance and a degree of emission limitation of no increase in emission rate" will handicap fossil fuel powered operators to expand capacity to meet America's growing energy consumption needs. Additionally, existing natural gas plants will need to adopt either CCS technologies or low-greenhouse gas (GHG) hydrogen by 2035. The EPA's proposed inclusion of energy attribute certificates to certify low-GHG hydrogen is yet another arbitrary regulatory deterrent for utilities to expand natural gas generated electricity. Complying with these BSERs risks exacerbating an impending energy security crisis by dissuading investment in reliable and dispatchable baseload power and encouraging utilities to adopt intermittent sources of renewable electricity.

Capping the emissions rate at natural gas power plants, America's leading source of low-carbon energy, places an artificial limitation on expanding America's leading source of affordable power. Requiring future sources of natural gas to use hydrogen co-firing will increase the cost of residential electricity as existing plants will need costly retrofits and an expensive hydrogen midstream infrastructure. Additionally, most hydrogen is produced as a byproduct of natural gas refining. Hydrogen produced through electrolysis is only as clean as the energy used to produce it. CCS is not economically viable at natural gas plants due to the low concentrations of CO_2 in the flue gas.[117]

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[115] Rea S. Hederman Jr., Michael E. Reed, and Trevor Lewis, ***The Economic Impact of A Potential New Clean Power Plan on Ohio and California***, The Buckeye Institute, April 12, 2023; F. Noel Perry, Colleen Kredell, Marcia E. Perry, Stephanie Leonard, **Paying for Electricity in California, How Residential Rate Design Impacts Equity and Electrification**, Next10, September 22, 2022.

[116] ***Demographic, Social, Economic, and Housing Characteristics for Selected Race Groups in Hawaii***, Research and Economic Analysis Division of the Department of Business, Economic Development & Tourism, March, 2018.

[117] Kazuya Goto, Katsunori Yogo, Yakyuki Higashii, "**A review of efficiency penalty in a coal-fired power plant with post-combustion CO2 capture**" Applied Energy, Volume 11 (November 2013) p. 710--720.

On May 4, 2023, four Federal Energy Regulation Commission (FERC) commissioners told the Senate Committee on Natural Resources and Energy that America was headed for an electricity reliability crisis.[118] Commissioner Mark Christie summarized the causes of the crisis as follows:

> The core of the problem is this: Dispatchable generating resources are retiring far too quickly and in quantities that threaten our ability to keep the lights on. The problem generally is not the addition of intermittent resources, primarily wind and solar, but the far too rapid subtraction of dispatchable resources, especially coal and gas.[119]

Coal accounts for nearly 20 percent of all electric power generated in America. When West Virginia Senator Joe Manchin asked the commissioners if America's power grid could maintain reliability if coal "pulled . . . off right now," all four commissioners agreed that it could not.[120] And removing coal from the national grid overnight would especially impact regions that depend heavily on coal for electric power. Appalachian states, like West Virginia and Kentucky, depend on coal for more than 65 percent of their electric power.[121] As Commissioner James Danly commented: "it is simply impossible to keep the system running entirely with unreliable intermittent generation."[122] Yet, the EPA's proposed rule would do exactly that by capping emissions at fossil fuel-fired power plants and pigeonholing future power generation to solely intermittent renewable sources.

Natural gas is cheaper and burns cleaner than coal, and replacing coal with natural gas could reduce power plant emissions in Appalachia's coal country. But limited pipeline capacity prevents that from happening. As Wyoming Senator John Barrasso observed during the May 4, testimony, "[i]n 2022, the least interstate natural gas pipeline capacity was added since [the energy information administration] began data collection in 1995."[123] Last year, the United States added a mere 897 million cubic feet per day of permanent interstate pipeline capacity from just five pipeline projects.[124] Permitting delays and cancelations have prevented large parts of the West Coast, New England, and Midwest, from accessing cheap natural gas. Expanding pipeline capacity would not only facilitate coal country's transition to cheaper natural gas, but it would also reduce methane emissions at wellheads. As FERC Commissioner Christie observed, expanding pipeline capacity is crucial for replacing shuttering coal plants: "We are not building a transportation capacity for gas units. Gas units increasingly are the ones that were being called upon to be the balancing resources when coal is retired prematurely, but if you can't get gas to the generating

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118 U.S. Congress, Senate, Committee on Energy and Natural Resources, ***Full Committee Hearing to Conduct Oversight of FERC***. 118th Cong., 1st sess., May 4, 2023.
119 ***Full Committee Hearing to Conduct Oversight of FERC*****: Testimony before the Committee on Energy and Natural Resources**, 118th Cong. (2023) (statement of Mark C. Christie, FERC commissioner).
120 *Ibid.*
121 Nikos Tsafos, **Phasing Out Coal from U.S. Electricity Increasingly a Regional Challenge**, CSIS, May 24, 2021.
122 U.S. Congress, Senate, Committee on Energy and Natural Resources, ***Full Committee Hearing to Conduct Oversight of FERC***. 118th Cong., 1st sess., May 4, 2023.
123 *Ibid.*

units, they can't run."[125] But the proposed rule's errant restrictions on emissions from natural gas fired power plants hinder the expansion of natural gas pipelines, ironically hindering expediting decarbonization of several regions living in energy isolation. Renewable power will not be able to meet these regional energy needs without natural gas generation. And without a cheap replacement for coal-fired electricity, Americans will pay more for the energy they consume.

Conclusion

The EPA has failed to adequately demonstrate CCS technology as a BSER for emission reduction under the CAA and fails Section 111(d)'s legal standard. The proposed rule leaves coal plant operators with functionally one option: shut down before 2040. The EPA's unwelcomed restrictions on natural gas risk dissuading investment in a cheap source of low-cost energy and pigeonholing producers into adopting expensive and unreliable intermittent sources of renewable power. States that have overbuilt renewable sources of power, like Texas and California, have had problems balancing power demand and power supply. This has led to power shortages, greater risk of brown- and blackouts, and households paying expensive surge prices for electricity. In its current form, the EPA's proposed rule promotes an unsustainable energy policy.

[125] *Ibid.*

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Appendix 17

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August 8, 2023

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2023-0072
1200 Pennsylvania Avenue, NW
Washington, DC 20460

RE: Comments from Minnkota Power Cooperative, Inc. on 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, 88 Fed. Reg. 33240, Docket ID No. EPA-HQ-OAR-2023-0072

Minnkota Power Cooperative, Inc. (Minnkota) appreciates the opportunity to provide comments on EPA's proposed rule 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" (the Proposed Rule).

Minnkota is a not-for-profit electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. We are comprised of 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota, and serve some 160,000 member cooperative rate-payers. Minnkota also serves as the operating agent for Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, MN. Since our formation in 1940, Minnkota has been committed to delivering safe, reliable, affordable and environmentally-responsible energy to its member owners.

Minnkota is proud of our extensive decarbonization efforts, including a renewable portfolio that comprises 42% of our current generation resources. Additionally, in 2015, Minnkota undertook the role as lead sponsor of a carbon capture and sequestration project (CCS) adjacent to the Milton R. Young Station (Young Station) to treat the flue gas from the facility's two cyclone lignite-fired coal units, located near the town of Center, North Dakota. Consequently, Minnkota, as the owner-operator of Young Station, has a strong interest in commenting and finds itself in an unusual position in relation to the Proposed Rule.

Although Minnkota strongly supports investment in CCS technology, the Proposed Rule overstates the technologies current and future capabilities as well as the timeline in which CCS can feasibility be deployed. Other aspects of the Proposed Rule pose new, grave reliability concerns stimulating additional premature retirements and further compounding the existing dispatchable generation shortage. As a small, cost-sensitive cooperative, Minnkota urges EPA to consider the perspective of utilities with fewer generating assets.

Though Minnkota is better positioned than most, even Project Tundra would not fully comply with EPA's mandate as presented. We encourage EPA to act on the following requests:

- Wholly revise and reconsider its BSER approach for new and existing generation;
- Adopt reasonable BSER strategies achievable at the unit;
- Decline to proceed with technologies not available to all EGUs, such as carbon capture and sequestration and hydrogen co-firing, as BSER for existing coal-fired and new and existing natural gas-fired units;
- Decline to adopt illegal source redefining, such as fuel-switching (coal to natural gas), as BSER;
- Choose timeframes that accommodate all sources and small business concerns;
- Evaluate grid reliability impacts of its proposal, taking into account the rapid resource transitions, lessons learned from recent generation curtailments, generation scarcities, and transmission constraints that IPM does not cover;
- Adopt a safety valve with two prongs: (1) One that may be used, generally, to buffer key fossil resources from retirement; and (2) Another that operating resources may avail themselves of in emergency circumstances to operate temporarily above GHG emissions limits or capacity factor restrictions;
- Revise and simplify Section 111(d) state plan requirements to remove content burdens, engagement duplicity, and allow for meaningful remaining useful life and other factors (RULOF) consideration; and
- Consider the cumulative financial impact of EPA's suite of environmental regulations on nonprofit, smaller utilities.

Thank you for your consideration of the following more detailed comments. Minnkota looks forward to engaging with EPA concerning this Proposed Rule. Should you have any questions regarding these comments, please contact Shannon Mikula at 701.795.4211 and smikula@minnkota.com.

Sincerely,

Shannon R. Mikula

Shannon R. Mikula, Environmental Manager
Special Projects Counsel

Enclosure.

Minnkota Power Cooperative, Inc.

Comments on 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, Docket ID No. EPA–HQ– OAR–2023–0072

I. Introduction.

Minnkota Power Cooperative (Minnkota) appreciates the opportunity to comment on the Proposed Rule. Minnkota finds itself in an unusual position in relation to this Proposed Rule.[1] Minnkota is proud of our extensive decarbonization efforts, including renewables that comprise 42% of our current generation resource portfolio. Additionally, in 2015, Minnkota undertook the role as lead sponsor of a carbon capture and sequestration project (CCS) adjacent to the Milton R. Young Station (Young Station) to treat the flue gas from the facility's two lignite-fired coal units. With countless hours of dedicated work and investment, the CCS project, known as Project Tundra, is close to becoming a feasible option to further reduce Minnkota's carbon footprint. Minnkota is proud of the work completed to-date to explore promising carbon capture technology, but we also remain very concerned about the ability to achieve the unrealistic timelines and standards set forth in this rule.

Reliability has and always will be essential to Minnkota and our member owners' mission. Federal agencies, lawmakers, and regional transmission organizations (RTOs) have articulated fears of a reliability crisis. In May, the Federal Energy Regulatory Commission (FERC) spoke before the Senate Committee on Energy and National Resources on this topic. Commissioner Christie testified:

> The United States is heading for a reliability crisis. I do not use the term "crisis" for melodrama, but because it is an accurate description of what we are facing. I think anyone would regard an increasing threat of system-wide, extensive power outages as a crisis. In summary, the core problem is this: Dispatchable generating resources are retiring far too quickly and in quantities that threaten our ability to keep the lights on. The problem generally is not the addition of intermittent resources, primarily wind and solar, but the far too rapid subtraction of dispatchable resources, especially coal and gas.[2]

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[1] The "Proposed Rule" refers to the rulemaking entitled, "The 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 (May 23, 2023).

[2] Testimony of Commissioner Mark Christie, FERC Commissioner, to the Senate Committee on Energy and National Resources, May 4, 2023, https://www.energy.senate.gov/services/files/1D618EDD-7CED-4BC5-8F09-C8F0668FE608 .

The math does not add up. Dispatchable generation is retiring faster than replacement resources are coming online. In the MISO[3] region where Minnkota resides, the dearth of dispatchable resources is well-documented and places the entire region on a heightened capacity shortage alert. Electricity demand is on the rise, but EPA's suite of new environmental regulations will handcuff the ability of utilities to meet that demand. Minnkota has joined with industry peers and the State of North Dakota to express our deep concern over the implications of the Proposed Rule. While EPA did not respond, we remain ready to engage in that discussion, particularly given the critical nature of the impacts.[4]

Minnkota is a not-for-profit electric cooperative and small business entity that powers rural communities in eastern North Dakota and northwestern Minnesota. These communities depend on Minnkota to provide cost-effective electricity to sustain rural residences, businesses, schools, and farms. Cooperatives have also sounded the reliability alarm. The cooperative trade association, National Rural Electric Cooperative Association (NRECA), recently underscored the reliability crisis in our country and called for new government regulations to cease "forcing the disorderly closure of always-on power plants in favor of renewables" to prevent demand from exceeding supply during critical times.[5]

Although Minnkota strongly supports investment in CCS technology, the Proposed Rule overstates its current and future capabilities and the timeline in which CCS can feasibility be deployed. Other aspects of the Proposed Rule pose new, grave reliability concerns, stimulating more premature retirements and further compounding the existing dispatchable generation shortage. As a small, cost-sensitive cooperative, Minnkota urges EPA to consider the perspective of utilities with fewer generating assets. The Proposed Rule places a proportionally greater strain on cooperatives. Even though Minnkota is better positioned than most, even Project Tundra would not fully comply with EPA's mandate.

Furthermore, this Proposed Rule is actually *five* regulatory actions that EPA has compiled together as one vast and complex rulemaking. The complexity of this rulemaking is striking, including hundreds of pages of backup documents, many of which have reference attachments. Numerous stakeholders requested that EPA extend the public comment period for this impactful suite of greenhouse gas regulations. EPA provided only 15 additional days. A 75-day comment period is completely insufficient for Minnkota to examine the impacts of EPA's proposal on its existing fleet and consider how new generation would be built. The Proposed Rule presents a myriad of technical issues concerning the feasibility and timing of EPA's proposed best system of emissions reduction (BSER) that require outside technical support. Minnkota has a small

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[3] MISO stands for "Midcontinent Independent System Operator."
[4] Remarks of Senator Cramer from North Dakota to the Senate Environment and Public Works Committee on the Nomination of Joseph Goffman, March 1, 2023.
[5] NRECA, Along Those Lines: Raising the Alarm on Grid Reliability," June 22, 2023 (podcast with Jim Matheson, CEO of NRECA, and David Tudor, CEO of Associated Electric Cooperative), https://www.electric.coop/along-those-lines-raising-the-alarm-on-grid-reliability

environmental staff, as do many not-for-profit cooperatives. EPA has completely inundated staff with other rulemakings during the same time period as the Proposed Rule. In fact, during the 75-day comment period for this proposal, Minnkota had to consider and comment on three other rulemakings specifically targeted at the power sector and substantially impacting our fleet:

- Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category that ended May 30;
- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review that ended June 23; and
- Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments that ended July 17.

EPA's refusal to grant an extension for this Proposed Rule has put Minnkota at a severe disadvantage to place meaningful comments into the record and to fully examine the impacts of the proposal on our ability to deliver affordable and reliable electricity to our members. We ask EPA to re-open the comment period for an additional 45 days, at a minimum, past the current deadline of August 8.

Minnkota is a member of the Lignite Energy Council (LEC) and the National Rural Electric Cooperative Association (NRECA). Minnkota supports the comments of these groups and incorporates their comments and technical support by reference.

Minnkota summarizes its requests related to this rulemaking, as follows:

- Wholly revise and reconsider its BSER approach for new and existing generation;
- Adopt reasonable BSER strategies achievable at the unit;
- Decline to proceed with technologies not available to all EGUs, such as carbon capture and sequestration and hydrogen co-firing, as BSER for existing coal-fired and new and existing natural gas-fired units;
- Decline to adopt illegal source redefining, such as fuel-switching (coal to natural gas), as BSER;
- Choose timeframes that accommodate all sources and small business concerns;
- Evaluate grid reliability impacts of its proposal, taking into account the rapid resource transitions, lessons learned from recent generation curtailments, generation scarcities, and transmission constraints that IPM does not cover;
- Adopt a safety valve with two prongs: (1) One that may be used, generally, to buffer key fossil resources from retirement; and (2) Another that operating resources may avail themselves of in emergency circumstances to operate temporarily above GHG emissions limits or capacity factor restrictions;

- Revise and simplify Section 111(d) state plan requirements to remove content burdens, engagement duplicity, and allow for meaningful remaining useful life and other factors (RULOF) consideration; and
- Consider the cumulative financial impact of EPA's suite of environmental regulations on nonprofit, smaller utilities.

We appreciate EPA's consideration of our more detailed comments herein and look forward to future engagement on these matters.

II. Background.

A. Minnkota Power Cooperative

Minnkota Power Cooperative is a not-for-profit electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. Minnkota provides wholesale electric energy to 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota. Minnkota also serves as the operating agent for the Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, MN.

Minnkota is the operator and a partial owner of the Milton R. Young Station (Young Station), a two-unit, cyclone lignite coal-fired power plant located near the town of Center, North Dakota. Minnkota owns and operates Unit 1, while also operating Unit 2 on behalf of Square Butte Electric Cooperative. Square Butte is owned by the same 11 member-owner cooperatives associated with Minnkota and shares the same management. Minnkota has no plans to retire the Young Station, which is the key generation asset of the cooperative. Minnkota's electric generation portfolio also includes renewable energy purchased primarily from three North Dakota wind farms, and hydroelectricity purchased from the Garrison Dam in central North Dakota. In all, renewables and hydroelectric power comprise 42% of Minnkota's nameplate generation capacity. Minnkota exists as a not-for-profit cooperative for the sole purpose of meeting the generation and transmission needs of our distribution cooperative member owners.

Minnkota and its project partners are pursuing construction of a CCS project adjacent to the Young Station known as Project Tundra. It will be North America's largest CCS facility when it commences operation. The project will treat the flue gas of Units 1 and 2 to reduce and capture CO2 emissions. The project is designed to capture CO2 at a rate of about 95% of the treated flue gas from either unit at the Station, with the CO2 stored more than a mile underground.[6] The project will be two and a half times the size of the Petra Nova project.

[6] Project Tundra, About, https://projecttundrand.com/about.

III. The Proposed Rule Disproportionally Affects Electric Cooperatives and the Rural Communities They Serve.

A. EPA has not adequately considered the impacts of the Proposed Rule on the Cooperative Community.

EPA must consider the specific and important challenges of not-for-profit, consumer-owned electric cooperatives as a distinct portion of the utility sector. Cooperatives require time and resources to meet the requirements posed by the Proposed Rule. For this reason, Minnkota requests EPA's consideration of challenges specific to cooperatives.

1. Background: Electric Cooperatives.

(a) *The Electric Cooperative Portion of the Power Sector*.

The electric cooperative network is composed of 831 distribution cooperatives. They were built by and serve co-op members in the community with the delivery of electricity and other services. All but the three largest electric cooperatives qualify as "small businesses" under Small Business Administration standards.

Cooperatives serve 42 million people predominantly rural areas, including 92% of persistent poverty counties. The sector powers over 21 million businesses, homes, schools and farms in 48 states. Cooperatives sell most of their power to households rather than businesses, unlike investor-owned utilities (IOUs). They operate at cost and without a profit incentive. They are owned by the members they serve with no independent stockholders. Rate affordability is crucial for consumer-members at the end of the line. Costs are borne across a base of fewer consumers and by families that already spend more of their limited incomes on electricity than do comparable municipal-owned or IOU customers. Data from the U.S. Energy Information Administration show that cooperatives serve an average of eight consumers per mile of line and collect annual revenue of approximately $19,000 per mile of line.

Today, Cooperatives rely on a diverse energy mix. From 2010 to 2021, cooperatives more than tripled their renewable capacity from 3.9 gigawatts to more than

13 gigawatts. Co-ops added over 900 MW of new renewable capacity in 2022. More than two-thirds of the electricity delivered by cooperatives comes from low- or zero-carbon sources. Cooperatives are committed to the environment. Our portion of the power sector has reduced SO2 emissions 82% from 2005 to 2021, while NOx emissions reduced 68%.[7]

(b) *History and Mission of Electric Cooperatives to Serve Rural America.*

In the 1930s, nine out of ten rural homes did not have electric service. Rural economies were exclusively dependent on agriculture. In 1933, President Roosevelt promoted the electrification of these rural areas. On May 11, 1935, Roosevelt signed Executive Order No. 7037 establishing the Rural Electrification Administration (REA), now the Rural Utilities Service (RUS), an arm of the Department of Agriculture. REA provided financing of cooperative projects. In 1937, the REA drafted the Electric Cooperative Corporation Act. The Act created a model to enable states to form and operate of not-for-profit, consumer-owned electric cooperatives. By 1953, more than 90 percent of U.S. farms had electricity. Today, 99 percent of the nation's farms have service. This success was made possible by locally-owned rural electric cooperatives that got their start by borrowing funds from REA to build lines and provide service on a not-for-profit basis.

Since the 1970s, the cooperative energy sector has been coal-heavy. In response to a Congressional mandate, electric cooperatives built approximately two-thirds of the coal-fired units in the electric cooperative fleet under the 1978 Powerplant and Industrial Fuel Use Act, prior to its repeal. The Act pushed electric cooperatives to build significant new "coal capable" baseload generation for self-generation to preserve natural gas supplies. Some cooperatives still have outstanding loan debt on these investments, in part due to the cost of environmental retrofits to meet evolving regulations such as Regional Haze.

(c) *Electric Cooperatives have special financing considerations that increase project timeframes.*

The Proposed Rule would require major capital investments in new generation and large retrofit projects for coal-fired generation. Transmission projects are also likely to support new generation. EPA's small business analysis and deployment timelines must account for additional time to obtain financing. The largest financier of cooperative capital projects is RUS. RUS has historically served cooperatives, with the mission of electrifying and maintaining critical infrastructure in rural America.[8]

[7] https://www.electric.coop/electric-cooperative-fact-sheet

[8] For more information about RUS and its essential role for the cooperative community, see https://www.rd.usda.gov/about-rd/agencies/rural-utilities-service (*visited June 3, 2022*) ("The Electric Program provides funding to maintain, expand, upgrade and modernize America's rural electric infrastructure. The loans and loan guarantees finance the construction or improvement of electric distribution, transmission and generation facilities in rural areas. The Electric Program also provides funding to support demand-side management, energy efficiency and conservation programs, and on-and

Obtaining RUS financing is a multi-step process. During project development and prior to construction, the cooperative's project engineering team must prepare initial scoping and draft a project justification for the projected dollars to be spent. This process involves reaching out to third-party vendors to confirm cost estimates, design, and operational specifications. RUS must approve the Work Plan.

RUS financing requires compliance with the National Environmental Policy Act (NEPA), which adds additional time at the beginning of a large project. The U.S. Department of Agriculture (USDA) regulates actions financed by RUS requiring environmental review. The environmental review requirements are set forth by NEPA, which require all federal agency actions or approvals go through a standardized environmental review process to evaluate what effect their proposed actions (projects) would have on the environment. Environmental reviews require development of Environmental Reports (ER), Environmental Assessments (EA), or Environmental Impact Statements (EIS) depending on the complexity/scale of the project.[9]

The environmental review process and timelines depend upon the scope of the project and ultimately what project documents RUS will request that the cooperative submit; however, a large control device project is likely to trigger an EA.[10] RUS reviews the EA or other environmental document and may require additional information, additions or revisions to the EA during the review process. Ultimately, RUS adopts the EA at the conclusion of the review process. RUS then publishes a public notice of the availability of the EA. The public notice and comment process commences, which would involve notice of the issuance of a Finding of No Significant Impact (FONSI), if RUS makes this finding.[11] Borrowers must wait for the conclusion of RUS's environmental review before taking any action on projects or obtaining RUS financial assistance.[12] Once RUS releases funds, the project engineering design and competitive bidding process may commence.

While other financing options may be available for certain types of projects, the interest rates are significantly higher. Cooperatives are nonprofits and their end-users of electricity are in rural communities sensitive to rate increases. For these reasons, Minnkota is a regular RUS borrower to finance environmental compliance and other projects.

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off-grid renewable energy systems. Loans are made to cooperatives, corporations, states, territories, subdivisions, municipalities, utility districts and non-profit organizations.").

[9] *See* 7 CFR § 1970.8 (describing the extent of the environmental review).

[10] For reference, *see* Environmental Assessments for other cooperative projects located on the RUS website: https://www.rd.usda.gov/resources/environmental-studies/assessments. Projects include transmission line, renewable generation, and fossil generation.

[11] RUS outlines the environmental review process in detail on its website and provides a step-by-step flowchart of the process. We provide a link to this information for EPA's reference for inclusion into the record: https://openei.org/wiki/RAPID/Roadmap/9-FD-h

[12] *See* 7 CFR § 1970.12.

In Minnkota's experience, EPA must factor in at least an additional 18 months *on top of the Proposed Rule's projected time* to allow cooperatives to obtain financing for new generation and large retrofit projects for coal-fired generation. Infrastructure and transmission projects will be needed to support these projects.

2. Rural Communities require affordable energy to thrive.

Electric co-ops sell the majority of their power to households rather than businesses. Keeping rates affordable is especially important for consumer-members at the end of the line. Environmental compliance decision-making demands balancing the air quality benefit on a rural community against the associated compliance costs (energy cost). The Proposed Rule cites no direct health benefits from lowering greenhouse emissions. To justify the rule, EPA finds that reducing greenhouse gases will have indirect benefits to environmental justice communities that face the impacts of climate change. EPA also bootstraps alleged co-benefits regarding other pollutants – highlighting reductions in ambient levels of PM 2.5 and ozone exposure.[13] EPA must recognize that the justification for the Proposed Rule primarily relies on benefits that are indirect and theoretical to the communities ultimately footing the bill. In comparison, increased energy costs are concrete. EPA should factor in the cost impacts of this Proposed Rule on rural communities.

3. The specialized needs of electric cooperatives must be considered.

The Proposed Rule overburdens the cooperative community in the following specific ways:

- Difficulty absorbing and/or raising money for the unprecedented number of environmental compliance rulemakings proposed by the Biden Administration. Cooperatives do not have investors from which to raise money. Large, capital-intensive projects are a substantial investment for smaller entities. Inflation Reduction Act (IRA) funds are not necessarily available to bridge the financial gaps. EPA's rulemaking "asks" result in an unprecedented financial burden that falls in a short time period between now and 2030, and for cooperatives will imply substantial rate increases to comply.
- Smaller generating systems have fewer compliance options when faced with multi-faceted, complex rules, such as the Proposed Rule. With fewer units in operation to leverage to meet power generation needs, cooperative systems are not as nimble as larger IOU systems that have varied baseload assets. IOUs have more assets to meet generation demands while complying with the Proposed Rule. Trading programs and averaging are often not useful for cooperative systems that have fewer units in these programs. With fewer units and plants to average or trade, these solutions place cooperatives at a disadvantage. In addition, while units are in outage for compliance projects, cooperatives have fewer resources to make up the generation deficit, and would be subject to potentially high-cost replacement energy.

[13] Proposed Rule at 33247, 33413.

- Cooperatives have greater infrastructure needs. To power 56% of America's land mass, large spans of infrastructure is required. Rural areas are electrified by miles of transmission lines. The Proposed Rule calls for brand new infrastructure for hydrogen and CO2 transportation, separately. This infrastructure must be developed over America's rural areas to ensure that the plants serving these cooperative service territories install BSER to be compliant. Vast service territories make this task more challenging for cooperatives, particularly in areas in which the geology does not support hydrogen or CO2 storage.
- Insufficient time to pursue project financing for projects to retrofit existing generation to comply with the proposal, or in lieu, to build new generation to bridge the gap. Environmental compliance requires time for project planning, man-power, and financing. Cooperatives cannot simply raise funds through investors. Project financing is needed through RUS or, if affordable, private resources.
- Coal-heavy cooperatives are disproportionately impacted. Cooperatives with small systems that rely on coal are placed in an impossible position. The Proposed Rule shuts down the coal by failing to provide enough time to construct CCS projects. Without other non-coal units to gap-fill, these cooperatives have few options.

Minnkota requests that EPA factor in the impacts of the Proposed Rule on cooperatives. A generalized cost analysis is inadequate. The Regulatory Impact Analysis should specifically account for impacts on this subset of the utility sector.

III. EPA's BSER proposal is not adequately demonstrated.

EPA's determinations of BSER for new and existing EGUs are far beyond the boundaries of CAA Section 111 or even what EPA has promulgated under Section 111 in the past. The Proposed Rule sets GHG emissions standards for fossil fuel-fired coal, oil, and natural gas generating units. EPA requires units, depending on category and fuel burned, to deploy CCS or low-GHG hydrogen combustion. EPA's determination of the "best system of emissions reduction" must be adequately demonstrated to comply with Congress's mandate.

> The term "standard of performance" means 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 (considering the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been *adequately demonstrated*.

Courts have drawn EPA's boundaries for selecting BSER. As a fundamental principle, EPA's BSER decision must be the result of "reasoned decisionmaking."[14] The BSER technology must not be a "purely theoretical or experimental" means of controlling air pollution.[15] EPA's task is to make a projection based on existing technology subject to the "restraints of reasonableness and cannot be based on 'crystal ball' inquiry." This determination is partially based on the time in which the technology will be available.[16] While a standard can be predictive, courts look at EPA's record for evidence to determine whether it is achievable in the expected time frames.[17]

Minnkota's trade association partners have undertaken extensive studies of EPA's BSER – CCS and hydrogen co-firing. Minnkota endorses these studies and adds its perspective, particularly with respect to navigating CCS on existing coal-fired generation. Minnkota confidently joins industry's position that EPA has chosen a BSER that is not adequately demonstrated and certainly not attainable within the deployment timelines that EPA has recommended.

A. CCS is not adequately demonstrated.

1. The Proposed Rule's record is insufficient to support CCS as BSER.

Minnkota shares EPA's enthusiasm for the promise of a CCS as an effective method of reducing carbon emissions. Our cooperative has specialized knowledge to comment on the Proposed Rule given the time spent since 2015 on project development to bring CCS to the Young Station.

Minnkota has reviewed EPA's justifications that CCS is adequately demonstrated. The record is insufficient to support this claim. EPA identifies only a small list of projects and includes a project rife with technical issues, a non-operating project, and a small pilot project:

- SaskPower Boundary Dam Unit 3 (110 MW lignite-fired unit in Saskatchewan, Canada), the only currently operating project of the three.
- Petra Nova capture facility (240 MW capture at Parish Generating Station in Texas)
- Plant Barry (25 MW capture in Mobile, Alabama)[18]

To be adequately demonstrated, both the carbon capture and the storage aspects of the proposal must be addressed. With respect to carbon capture itself, EPA

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[14] *National Asphalt Pavement Ass'n v. Train*, 539 F.2d 775 (D.C. Cir. 1976) (citing *Essex Chem. Corp. v. Ruckelshaus*).
[15] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973) (citing Senate Report).
[16] *Id.* at 391-92.
[17] *See, e.g., Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981) (considering vendor information that stated the SO2 standard was achievable and overlooking data shortcomings, such as limited test information).
[18] Proposed Rule at 33293.

proposes full-scale installations achieve 90 percent capture rates with cost estimates based on recent coal fleet average capacity of 400 MW. However, EPA identifies only a small list of CO_2 capture projects.[19] None of the cited projects have demonstrated successful operation and capture on a scale than would be deployed to accommodate larger power generating units in the country.

Only Petra Nova has operated at a coal-fired facility in the United States. That was only a slip-stream project, and CCS is not currently in operation there. While the Boundary Dam, Canada installation demonstrated more continuous operation, that project is on a single, small capacity unit that does not correlate to the capacities contemplated by the Proposed Rule. There are no known CCS projects on natural gas units.

With respect to the storage component of the process, Minnkota agrees with EPA's assessment that geologic sequestration of captured CO2 is available in certain parts of the country, such as in North Dakota. Yet, it is not available universally. EPA acknowledges this fact but fails to offer an effective, cost-reasonable solution. The likely outcome for less fortunate sites is unit shutdowns where compliance is not available.[20] As discussed in Section VI, EPA cannot legally choose non-operation as BSER.

The record is riddled with timing underestimates. In Minnkota's experience, the rigorous timeline offered by EPA cannot be met by sources that have not already begun CCS project development. For example, EPA projects just two to three years to characterize and permit a storage facility but neglects to consider difficulties in obtaining Class VI permits for storage facilities or, in the alternative, difficulties in permitting and installation of a pipeline, if on-site storage is unavailable.

2. <u>Minnkota's CCS project experience is not consistent with many of EPA's project assumptions</u>.

CCS technology is important to support economy-wide decarbonization. However, EPA makes assumptions about operations, equipment capabilities and timing that are inaccurate based on Minnkota's project experience. EPA must revise and reconsider its optimistic suppositions about cost, project schedule, operational flexibility, and regional viability of CCS.[21] Minnkota's experience with Project Tundra is instructive to this proposal. EPA's feasibility assumptions and timeline must also be reconsidered.

(a) Feasibility of Carbon Capture.

<u>Carbon capture is a pre-demonstration technology</u>. CCS is feasible but not adequately demonstrated. To be adequately demonstrated, CCS must be possible at

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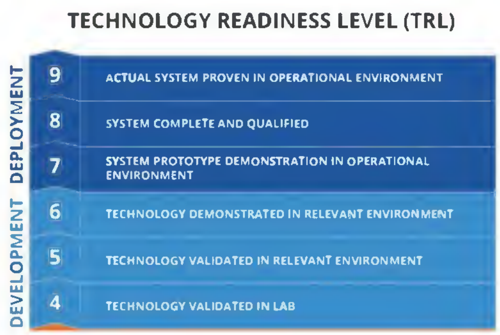
[19] EPA, Spreadsheet of CCS facilities, EPA-HQ-OAR-2023-0072-0061_attachment 1
[20] EPA acknowledges that all areas of the country do not have geologic sequestration capabilities. Proposed Rule at 33298
[21] EPRI Comments, filed separately in this docket at Section 2.1 and 2.2.

all sites with existing coal-fired units, at all boiler-types, and at all loads. Minnkota's experience confirms this is not true. Of most significance, CCS has not been proven, even as a pre-demonstration project, at the size needed to treat the flue gas of a large coal-fired EGU.



Project Tundra is financed as a Technology Readiness Level (TRL) 7 project. TRL 7 projects are defined as "system prototype demonstration in an operational environment." TRL 7 projects have results from testing a prototype system in an operational environment but the technology has not been proven to work in its final form and under expected conditions to achieve TRL 8 status. TRL 9 projects are proven in the operating environment.

While BSER does not require pilot tests, evidence must be in the record to support CCS application at larger scales. The Young Station units are a 455 MW unit (Unit 2) and a 250 MW unit (Unit 1). The Tundra project only has capacity to treat 530 MW. Of consequence, the parasitic load of the project decreases the capacity of the units while the CCS system is operating due to electricity and steam requirements.

If carbon capture was demonstrated, Minnkota and its partners would not be able to finance Project Tundra as presently arranged. Project Tundra is requesting financing, in part, as a demonstration project through funds from the Department of Energy's (DOE) Office of Clean Energy Demonstrations (OCED). The Bipartisan Infrastructure Law enacted in December 2021 created the funding opportunity for *demonstration* projects.[22] Funding is not available for technologies that are proven at a commercial scale. To obtain funding from OCED, DOE looks at "technology readiness levels." It provides funds to projects that show advancing technology. The Project Tundra demonstration results from the bold investment to take CCS farther than before. The Project seeks to advance the technology readiness level of CCS by scaling up the technology (2.5x), applying it lignite, and showing successful operating in an extreme cold weather climate.

<u>Demonstration projects carry a perceived technology risk</u>. Minnkota has acknowledged and carefully calculated the technology risk, taking account of site-specific variables. A crucial assumption in Minnkota's calculus is that the Young Station units may operate and generate electricity *even if the CCS equipment has an outage*. In other words, if equipment issues arise – whether due to the CCS technology, equipment, increased scale, extreme temperatures, or variability in flue gas load – the CCS system may take a forced outage. Meanwhile, the Young Station units are able to generate electricity and emit flue gas through the current stack configuration while CCS is down and as it warms back up for service. Thus, the risk of equipment failure is much

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[22] DOE, OCED, OCED Funding Opportunity Exchange, https://www.oced-exchange-energy.gov/FAQ.aspx.

less impactful than if the entire Young Station must come offline for the entire duration of the CCS plant forced outage. In that event, Minnkota would be hedging its ability to meet generation needs on the CCS project equipment, a much different situation. The Proposed Rule would compel this result.

Carbon capture at a large-scale coal-fired unit or any natural gas unit has not been demonstrated. In fact, the Tundra project seeks to prove that large scale coal-fired application is possible. Project Tundra will be able to capture the CO2 emissions equivalent to a 530 MW unit.[23] Tundra's scale will be the largest capture system in the world and will employ the largest single train system that has been built by the project OEM. This large train is still not sufficient to cover EPA's anticipated scope, which in Minnkota's case would be 705 MW of flue gas. An additional CCS train would be necessary. This additional equipment would exponentially expand the project cost to only capture an additional 28% of load.

Carbon capture is not adequately demonstrated to continuously achieve a rate of 90% capture of CO2 based on a source-specific level of baseline emission performance. Project Tundra is designed to capture CO2 at a rate of about 95% from approximately 530 MW of the 734 MW produced at full load from a combination of Unit 2 and Unit 1 flue gas. The carbon capture process depends on a complex chemical reaction in the CCS absorber to strip the CO2 and capture it. Carbon capture efficiency will vary when the flue gas stream is at a lower load. Minnkota has no technical data or testing assurance that EPA's value of 90% capture can be achieved across varying unit loads. In addition, weather (seasonal temperature) impacts are anticipated to impact the CCS equipment function. No information is available to determine how the carbon capture rate may be affected. Based on Minnkota's understanding from project development, this demonstration project will help to fill in these gaps, which are presently unknowns. The Tundra project parameters were never dependent on achieving a specific capture rate continuously. Certainly, a margin for compliance would be required. EPA's aspirational 90% value is clearly speculative and unsupported. Further testing and vendor information is necessary to target an achievable capture percentage that could be applied to all unit sizes, project scales, weather conditions, pollution control trains, and load levels with a margin for compliance.

(b) Reliability Considerations.

The electrical and steam requirements of capture system is consequential. EPA should consider the practical consequences of CCS. The electrical and steam requirements of carbon capture systems will remove a significant amount of load from the grid. In Tundra's case, 205 MW from the Young Station units is needed to operate the adjacent CCS facility. In total, the CCS demand is about 31% of the Young Station's net capacity. This value is equivalent to retirement of a smaller generating

[23] The Project is designed to capture variable mixes of flue gas. At full load, the system will treat the flue gas of Young Unit 2 (a 455 MW unit) and 30% of the CO_2 emissions at Young Unit 1 (a 250 MW unit).

unit. The overall cumulative demand to serve multiple CCS facilities on the grid must be evaluated to determine the impacts on an already strained grid.

Forced outages due to CCS equipment failures will remove generation from the grid. At present, no regulatory requirements constrain the Young Station from operating if the CCS system experiences a malfunction or if MISO calls on the Young Station to run at full load, without a CCS-related derate, for grid stability. It is crucial to preserve the ability for units to function in must-run situations to abate a grid emergency. EPA must consider exemptions for CCS equipment malfunction events and for reliability needs.

(c) CCS Prcject Costs and Financing Limitations

CCS Projects are very expensive due to development, one-time capital costs, and ongoing operating costs. Project Tundra is estimated at a cost of approximately $1.4 billion.[24] The project will be financed by utilizing 45Q federal tax credits, which are currently $85 per ton of CO2 that is captured and stored in a geologic formation deep underground. Permitting is currently under way for an adjacent second CO2 storage site. If this federal subsidy were not in place, the project would not be economical. The extraordinary capital and annual operating costs of CCS are a statutorily-required consideration that EPA must factor into the analysis. These costs are even more substantial for smaller generators, such as cooperatives.

Financing options are essential but limited. CCS projects are only possible through multiple funding sources. Project Tundra will avail DOE funds, as well as assistance from the IRA. The state of North Dakota is providing a $250 million loan to assist the project. Private bank loans are more challenging to obtain for demonstration projects. A project of the scale needed to comply with the Proposed Rule would require even more funding. The increase in project cost just to treat the flue gas from both the Young Station units (28% more flue gas) would require a large sum of additional capital in addition to the IRA monies and the OCED grant to build a second CCS train and acquire more storage acreage.

(d) Sequestration Feasibility, Costs and other Considerations.

Many areas of the country do not have the geology to support sequestration. The Young Station happens to be placed on ideal geology for safely sequestering carbon. However, much study was necessary to arrive at this conclusion. In 2005, the Energy & Environmental Research Center (EERC) at the University of North Dakota started characterizing the geology within the state and targeting formations. It took the EERC over a decade just to characterize the geology. The graphical representation of the geology under the Young Station depicts the necessary elements for storage. Most sites do not have a deep porous rock layer to hold the CO2 and overlying cap rock layers will seal the CO2 in the storage zone.[25] Sites that do not have this geological

[24] https://www.projecttundrand.com/faq
[25] https://www.projecttundrand.com/co2-storage

setting must pump the extracted CO_2 to a storage area. Dedicated piping must be available, adding even more cost to the project.

<u>States with oil and gas frameworks, like North Dakota, will have a shorter timeline for exploring and permitting storage.</u> North Dakota has an oil and gas and mining regulatory framework to study sequestration geology and issue permits. Many states do not have any experience at all in this area. Time would be necessary to enable those states to develop a regulatory framework that supports sequestration and drilling and addresses ownership of pore space to lessen the possibility of future legal challenges for projects and permits.

<u>To obtain a Class VI permit to allow storage of CO_2 is an arduous data collection process</u>. A tremendous amount of information is needed. For example, EERC needed over a decade to characterize the geology. After that characterization, in 2020, Minnkota drilled two characterization wells to gather the necessary geologic data to support a permit application. This step was required to obtain a complete application.

<u>Class VI permits are expensive</u>. For Tundra, the storage permit cost upwards of $30 million. This cost is likely reduced because the work was performed during the COVID-19 pandemic lockdown when rig costs and labor were less expensive. In the future, the cost might be double, particularly when utilities are competing over limited drilling resources.

<u>Class VI permitting is a lengthy process</u>. North Dakota is one of only two states with primacy to issue Class VI permits. North Dakota engaged in two full sessions of state lawmaking to enact laws required for EPA to grant primacy. Sources in all other states must look to EPA to grant Class VI permits. At present, 33 permit applications are pending.[26] Even though some states are trying to attain primacy, that process is also time-consuming. If CCS becomes BSER, the backlog of pending applications is sure to increase.

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[26] Hunton Andrews Kurth, Class VI Program Permit Tracker, https://www.huntonak.com/en/class-vi-program-permit-tracker.html.

(e) EPA's CCS Prcject Timeline is unrealistic.

EPA's proposed timeline requires CCS units to be fully operational by January 1, 2030. This time frame cannot be achieved. For Project Tundra, project development took almost nine years of study and engineering analysis necessary to support a final decision on construction, despite exceptional geology at the Young Station. Carbon capture FEED studies take a minimum of 18 months (6 months for Pre-FEED studies plus 12 months minimum for a FEED study). Only four to five vendors actually have the capability to launch CCS projects. Minnkota has identified only two of those vendors able to develop CCS operations at the scale of Tundra.

For Project Tundra, the OEM selected, Mitsubishi, has been studying the flue gas characteristics of the Young Station since 2015. These studies ensure successful capture solvent performance. Environmental permitting has played a significant factor in the project timeline. The CCS facility requires water permits, an air permit, and transmission changes at the plant (re-routing). Once FEED studies, permitting, and other project development work is complete, the actual construction timeline will take three to four years. Since equipment is fabricated off-site, it must be ordered to specifications well in advance. Delays are possible due to labor storages or supply chain issues. Minnkota projects that Tundra will come on-line in 2029.

Construction timelines are likely to impacted by the demand the Proposed Rule would place on the small number of vendors available to develop and construct CCS projects. In addition, supply chain issues are anticipated and will increase the time necessary to achieve commercial operation. Compressors, other large rotating equipment, and the power distribution equipment such as large transformers and primary control modules must be commissioned, built, and installed. The Proposed Rule would stimulate many new CCS projects for coal and gas that would flood the field at the same time. Suppliers are likely to be overwhelmed and unable to provide equipment without lengthy waits.

To obtain the Class VI permit for Project Tundra, four years were required to obtain the permit, including characterization of the geology for the permit application, completing the Class VI permit application, holding hearings, and obtaining the final permit. Minnkota anticipates that sites in states without a subsurface regulatory framework and primacy will require much more time.

The CO2 pipeline from the generating unit to the storage site requires additional time. Project Tundra did not require a long pipeline -- only a quarter mile pipeline from the CCS equipment to the injection site on plant property. For a longer pipeline, a permit would be needed. Minnkota estimates an additional 18-month process to permit the pipeline, without accounting for any potential challenges.

To summarize, Project Tundra would not be completed in the time EPA has proposed, had the project begun today. Even for Minnkota, the currently designed and financed CCS system does not meet EPA's requirements. In addition, Minnkota does not have adequate time to develop, finance, design, and build a new capture train to further increase the project scale. Without time to construct a second CCS train by 2030, Minnkota would have to derate Unit 1 until either a new train or new generation could be built. The loss of 175 MW at Minnkota's only fossil generation station is very significant for the cooperative's ability to serve its customers with reliable, affordable electricity.

B. Natural gas co-firing is not adequately demonstrated on all coal-fired unit types.

Natural gas co-firing is an available option for many existing coal-fired steam boilers with modification. The level of modification is dependent on boiler design and existing infrastructure. With respect to some steam boiler types, the ability to co-fire has not been demonstrated.

In other cases, the ability to co-fire exists but the required infrastructure does not. The cost of building an entirely new natural gas pipeline is timing consuming and expensive. The Young Station has no gas line within 20 miles of the plant. In addition, typically the cost of gas on a cost per megawatt basis is more than 50% greater than the cost of coal and possibly even higher to ensure firm delivery. Replacement of coal with natural gas would substantially increase fuel prices for Minnkota. Further exacerbating the situation, EPA presents co-firing as a temporary ten-year extension solution from 2030 to 2040. For cost and timing reasons, co-firing is not a viable gap-filling opportunity for Minnkota to address the remaining flue gas that the Tundra project cannot accommodate.

IV. The Proposed Rule places reliable and affordable power at risk while energy demands surge.

The Proposed Rule targets baseload generation. Fossil resources ensure the power grid remains stable and compliment renewable assets. Even EPA recognizes that renewable generation cannot substitute for the crucial role of baseload generation. A balanced generation mix is fundamental due to extreme weather events and increased demand as electrification efforts incrementally rise each year.

A. The Proposed Rule's impact analysis illustrates dramatic implications for coal-fired power.

The Proposed Rule would set in motion an unprecedented change in the electricity generation grid within a short time period. Costs and infeasibility of BSER would force retirements that have yet to be announced. EPA has no provision for the replacement of this generation with reliable baseload resources.

EPA projects generation transitions in its baseline analysis (Table 12), which do not even take into account that the infeasibility of BSER will force more generation offline.[27] In 2028, EPA projects that coal generation without CCS will total 100 GW. EPA estimates that the Proposed Rule will cause reductions in coal capacity without CCS to 44 GW in 2030 and to 0 GW in 2035. Only 9 GW of coal-fired generation, with CCS installed, survives at all in 2040. EPA projects that renewable generation will begin at a baseline of 315 GW in 2028 and finish with 877 GW in 2040. Other generation fuel sources – oil and natural gas -- show small increases by 2040. Such a massive resource transformation requires careful planning and adequate time for RTOs to ensure grid reliability. The retiring coal generation must be replaced with reliable, dispatchable generation.

Table 12 2028, 2030, 2035 and 2040 Projected U.S. Capacity by Fuel Type for the Updated Baseline and the Illustrative Integrated Proposal Scenario

	Year	Capacity (GW)		Percent Change from Updated Baseline
		Updated Baseline	Integrated Proposal	Integrated Proposal
Coal	2028	100	99	-1%
Coal with CCS		0	0	-
Coal with Gas co-firing		0	0	-
Natural Gas		463	468	1%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		0	0	-
Nuclear		96	96	0%
Hydro		102	102	0%
Non-Hydro RE		315	316	0%
Oil/Gas Steam		63	63	0%
Other		7	7	0%
Grand Total		1,146	1,151	0%
Coal	2030	60	44	-25%
Coal with CCS		9	12	29%
Coal with Gas co-firing		0	1	-
Natural Gas		454	462	2%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		7	4	-39%
Nuclear		92	92	0%
Hydro		104	104	0%
Non-Hydro RE		403	405	0%
Oil/Gas Steam		60	70	15%
Other		7	7	0%
Grand Total		1,196	1,200	0%
Coal	2035	33	0	-99%
Coal with CCS		11	12	13%
Coal with Gas co-firing		0	1	-
Natural Gas		460	446	-3%
Hydrogen Co-firing		0	42	-
Natural Gas with CCS		10	6	-45%
Nuclear		84	84	0%
Hydro		108	108	0%
Non-Hydro RE		667	664	0%
Oil/Gas Steam		59	68	14%
Other		7	7	0%
Grand Total		1,439	1,438	0%
Coal	2040	28	0	-99%
Coal with CCS		8	9	12%
Coal with Gas co-firing		0	0	-
Natural Gas		503	515	2%
Hydrogen Co-firing		0	12	-
Natural Gas with CCS		10	6	-45%
Nuclear		79	79	0%
Hydro		110	110	0%
Non-Hydro RE		868	877	1%
Oil/Gas Steam		59	67	14%
Other		7	7	0%
Grand Total		1,672	1,683	1%

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind

Minnkota is in an enviable position as compared to other utilities. The Young Station has an ongoing CCS project and may even be included in EPA's estimates of surviving coal with CCS in 2040. However, Minnkota finds itself with serious concerns due to the Proposed Rule. As previously stated, with the present Tundra capture design, Minnkota would not be able to meet EPA's objectives in the Proposed Rule.

[27] EPA, Integrated Proposal Modeling and Updated Baseline Analysis: Memo to the Docket for 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 Proposal, July 7, 2023 (Docket ID No. EPA-HQ-OAR-2023-0072) at Table 12.

Minnkota has no replacement generation sufficient to cover the Young Station's capacity. Therefore, even Minnkota finds its generation resources in jeopardy.

B. MISO projects a high risk of generation shortfalls.

The MISO region is already in a precarious position, without regard to the shortfalls of generation that the Proposed Rule will cause. The North American Electric Reliability Corporation (NERC) performed a summer reliability assessment of all areas of the country, released in May 2023.[28] NERC reported the MISO region as an "elevated" potential for insufficient operating reserves in above-normal conditions, as depicted in Figure 1 from this report.

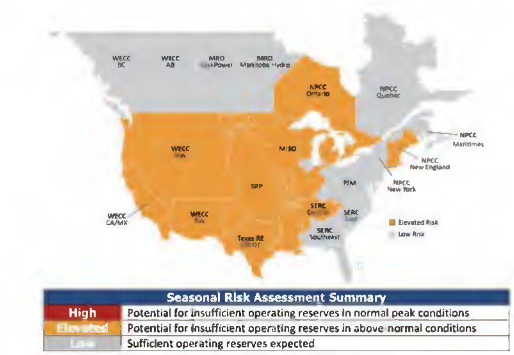

Figure 1: Summer Reliability Risk Area Summary

NERC notes that reserve margins are projected to manage normal summer peak demand. Other reliability factors cited in the analysis include fuel supply and infrastructure insufficiencies, restrictions due to the Good Neighbor Federal Implementation Plan (FIP), delays in interconnection of new generation, low replacement distribution transformer inventories, supply chain issues, and transmission congestion, among other factors.

Reliability concerns are present in other seasons. Many parts of North America are experiencing elevated temperatures in shoulder months (spring and fall) when owners and operators historically scheduled outages for maintenance. NERC warns utilities about potential capacity shortages and suggests that utilities take steps to mitigate, such as more conservative outage coordination periods.[29]

The existing stresses on the grid exist without the impacts of the Proposed Rule. With unachievable project timelines for existing generation, the Proposed Rule would cause unprecedented unit shutdowns without time to construct replacement generation. Generation shortfalls are not acceptable in cold climates, such as North Dakota, where residents depend on electricity to heat their homes. EPA must factor the precarious state of America's grid into its environmental compliance decisions.

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[28] NERC, 2023 Summer Reliability Assessment, May 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf (NERC 2023 Summer Assessment) at 7-8.
[29] NERC 2023 Summer Assessment at 8.

C. Power demands are on the rise in North Dakota.

In the first quarter of 2023, North Dakota was the top state in economic growth in the country at 12.4%, as measured by gross domestic product (GDP).[30] Economic prosperity is due to industry growth from mining, quarrying, oil and gas extraction. North Dakota has also seen gains in agriculture and forestry activities. These sectors are energy intensive industries, highly dependent on reliable power.[31] In fact, other areas of the MISO and Southwest Power Pool (SPP) footprint are seeing top tier economic growth. South Dakota and Nebraska also report substantial increases in GDP. All of these areas have an elevated risk of reliability concerns. This corridor of prosperity cannot weather more generation coming off-line. MISO already notes the dangers that EPA's environmental compliance agenda is causing the overall interconnected grid.[32]

Minnkota and its distribution cooperatives provide power to support economic development projects that provide transformational opportunities for the rural communities and residents they serve. Without reliable electricity, these opportunities cannot be realized. Unintentional consequences from the proposed regulatory changes will jeopardize the potential of creating highly skilled, highly compensated positions and careers.

Minnkota urges EPA to make responsible environmental compliance decisions in light of increased demand in its service area. Adequate baseload generation is needed to respond to increased demand. The Proposed Rule stands to deactivate grid resources.

D. Extreme weather events underscore the importance of a balanced generation mix, contrary to the Proposed Rule's policies.

Extreme weather events have been commonplace in both winter and summer. Recent weather events illustrate the importance of a balanced electricity grid during these circumstances that tax the grid. Recently, in the eastern part of the country, Winter Storm Elliott showed the imminent danger of grid emergencies and the need for reliability contingencies.

PJM, the RTO impacted by the storm released a report that identifies the causes of the emergency and significant generation shortfall. PJM concluded that the daily Appalachian gas production loss of approximately 30% of total northeast daily production caused a significant loss of gas supply for all downstream gas consumers, particularly larger, more efficient gas-fired power generation units that require supplies

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[30] U.S. Department of Commerce, Bureau of Economic Analysis, "Gross Domestic Product by State and Personal Income by State, 1st Quarter 2023," June 30, 2023, https://www.bea.gov/sites/default/files/2023-06/stgdppi1q23.pdf

[31] https://www.statista.com/statistics/1065144/north-dakota-real-gdp-by-industry/

[32] MISO identifies the FIP as a reliability driver. North Dakota is not subject to the FIP, but other states within the MISO interconnected grid are affected.

flowing at uniform and higher pipeline pressures to operate.[33] PJM reported that coal generation had fewer outages than gas generation. Wind resources performed well, but solar generation only met or exceeded its capacity expectations during a few hours each afternoon, which was not coincident with the peak electric demand periods.[34]

Focusing on Minnkota's geographic area, NERC observes that the reliability of MISO's portion of the grid hinges on the performance of wind generation. NERC states, "MISO can face challenges in meeting above-normal peak demand if wind energy output is lower than expected."[35] MISO itself predicted just enough capacity to serve its projected summer needs in a probable generation scenario.[36] Given the considerable hedge on wind energy, the Proposed Rule's push on the generation mix *away* from diversification is particularly disconcerting. By shutting down coal and minimizing the construction of new gas assets, renewable resources must save the day during a reliability crisis. Particularly in areas with extreme cold temperatures – like North Dakota – betting on the performance of wind and solar generation is an ill-advised gamble. A diversified generation portfolio is essential during emergency events. Where gas supplies fail, other resources, such as coal, must be available to assuage the crisis.

Taking these concerns and the weakened grid into account, Minnkota strongly supports a reliability safety valve for force majeure situations at a minimum.

VI. EPA's Section 111 proposal is illegal.

A. Congress did not delegate EPA the authority to re-shape the electricity sector.

EPA lacks the authority to promulgate the Proposed Rule – The far-reaching repercussions of the Proposed Rule exceed EPA's congressional grant of authority under CAA Section 111. A rule with such sweeping impacts on the entire energy sector must be promulgated under an express grant of authority.

Where Congress does not clearly express authority, an agency cannot regulate such significant matters. The federal agency must properly invoke a constitutionally enumerated source of authority to regulate an area. On this point, the Supreme Court provides: "We expect Congress to speak clearly" if it wishes to grant an executive agency authority over decisions "of vast economic and political significance."[37] The courts dub this concept the Major Questions Doctrine.

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[33] *Id.*
[34] *Id.*
[35] NERC 2023 Summer Assessment at 5.
[36] https://cdn.misoenergy.org/2023%20Summer%20Resource%20Assessment628978.pdf
[37] *Util. Air Regul. Grp. v. EPA*, 573 U.S. 302, 324 (2014) ("*UARG*"); *see also Alabama Assn. of Realtors v. Department of Health and Human Servs.*, 141 S.Ct. 2320 (2021) (Kavanaugh, J., concurring).

The Major Questions Doctrine rests on “two overlapping and reinforcing presumptions.”[38] The first presumption is that Congress “intends to make major policy decisions itself.” *Id.* Second, in making those decisions, Congress should default against delegating “major lawmaking authority.” *Id.*

The Proposed Rule plainly falls within the boundaries of a major question. A question is “major,” when the following factors are present: (1) the amount of money involved for regulated and affected parties and the overall impact on the economy, (2) the number of people affected, and (3) the degree of congressional and public attention to the issue.[39]

The Proposed Rule satisfies each of these factors:

- Exceptional financial impact on regulated parties and the United States economy as an “economically significant regulatory action” as defined by OMB, costing more than $100 million annually or will cause a material adverse effect on the economy;[40]
- Broad-reaching as to the number of entities affected (states, the utility sector, end users, small businesses, EGUs and all consumers of electricity; and
- Significant public attention of Congress, news outlets, states, and stakeholders[41]

The Proposed Rule will have transformative consequences on the entire energy economy and America’s electricity grid. Reliable electricity is essential to support the entire economy. Electricity is an “essential” and foundational element of modern life.[42] The electric power industry is a “significant portion of the American economy.” In comparison, the Supreme Court considered an attempted overhaul of the tobacco industry to be a major question.[43] The Proposed Rule will result in substantial modifications to the U.S. energy supply sector and significant grid reliability issues for 84 million Americans.

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[38] *U.S. Telecom Ass’n v. FCC*, 855 F.3d 381, 419 (D.C. Cir. 2017) (Kavanaugh, J., dissenting from denial of rehearing en banc).

[39] *Id.* at 422-23 (Kavanaugh, J., dissenting from denial of rehearing en banc); *see UARG*, 134 S.Ct. at 2443-44 (regulation would impose massive compliance costs on millions of previously unregulated emitters); *Gonzales v. Oregon*, 546 U.S. at 267 (physician-assisted suicide is an important issue subject to “earnest and profound debate across the country”); *Brown & Williamson*, 529 U.S. at 126-27, 133, 143-61 (FDA’s asserted authority would give it expansive power over tobacco industry, which was previously unregulated under the relevant statute); *MCI Telecommunications Corp. v. Am. Telephone & Telegraph Co.*, 512 U.S. 218, 230-231, (rate-filing requirements are “utterly central” and of “enormous importance” to the statutory scheme).

[40] *See* https://www.reginfo.gov/public/jsp/Utilities/faq.myjsp

[41] *See, e.g.,* House Committee on Energy and Commerce, Environment Hearing: “Clean Power Plan 2.0: EPA’s Latest Attack on America’s Electric Reliability,” June 6, 2023, https://www.youtube.com/watch?v=lxJDm_QvRzI

[42] *Puerto Rico v. Franklin Cal. Tax-Free Tr.*, 136 S. Ct. 1938, 1950 (2016).

[43] *Brown & Williamson*, 529 U.S. at 159.

Section 111 did not delegate power to EPA to restructure the energy sector. In the instant rulemaking, EPA has selected a BSER that is so stringent, expansive, and infeasible that effectively shuts down coal and erects hurdles for operation of gas-fired generation. The Proposed Rule will force the country's generation mix away from fossil fuels, especially coal, by 2032 or sooner. The Supreme Court has recognized the limits of EPA's powers in *West Virginia*. The Supreme Court recently stated in the context of Section 111:

> Capping carbon dioxide emissions at a level that will force a nationwide transition away from the use of coal to generate electricity may be a sensible "solution to the crisis of the day." *New York v. United States*, 505 U.S. 144, 187, 112 S.Ct. 2408, 120 L.Ed.2d 120 (1992). *But it is not plausible that Congress gave EPA the authority to adopt on its own such a regulatory scheme in Section 111(d). A decision of such magnitude and consequence rests with Congress itself, or an agency acting pursuant to a clear delegation from that representative body.* The judgment of the Court of Appeals for the District of Columbia Circuit is reversed, and the cases are remanded for further proceedings consistent with this opinion.[44]

EPA opted not to heed the Supreme Court's direction, adopting the most aggressive and transformative rule of our time. The Court's view on Section 111(d) is precise, describing it as "the previously little-used backwater."[45] In that portion of the CAA, Congress would not have conferred upon EPA the authority to decide "how much coal-based generation there should be over the coming decades."[46] Congress's decisions to pass on an extensive greenhouse gas regulatory program further supports the Court's conclusion as to EPA's authority.[47]

As presented in these comments, the Proposed Rule's objectives and future impacts are undisputable and bold. EPA fashions coal-fired generation categories based on retirements. It attaches unquestionably expensive and infeasible requirements to non-sunsetting units as the only path away from retirement. By placing unachievable technologies, coal-fired units are set up to fail. In this way, EPA substantially overreaches the guiderails of its Section 111 power to summarily erase the coal-fired fleet. EPA even takes a further step by inflicting an unachievable BSER on larger gas-fired units. EPA must withdraw this expansive proposal. Major questions are triggered by stepping into energy markets and imposing a substantial monetary impact on the United States. economy. The CAA does not grant EPA this expansive authority.

B. EPA has overreached into the jurisdiction of other agencies charged with managing the country's energy resources.

EPA's expansive Proposed Rule illegally broadens its agency jurisdiction and intrudes into the delegated space of other agencies and entities that regulate energy policy, energy transmission, and electricity rates. FERC regulates interstate energy

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[44] *West Virginia v. EPA*, 142 S.Ct. 2587, 2616 (2022) (emphasis added).
[45] *Id.* at 2613.
[46] *Id.*
[47] The Court cited Clean Power Plan-type CAA amendments that Congress rejected. *Id.* at 2614.

policy. FERC has delegated its authority to ensure grid reliability to the North American Electric Reliability Corporation (NERC). As part of the Energy Policy Act of 2005, Congress gave FERC the responsibilities of protecting the reliability and cybersecurity of the Bulk-Power System through the establishment and enforcement of mandatory reliability standards. FERC regulates the transmission and wholesale sale of electricity in interstate commerce. A FERC goal is "facilitating the development of the electric infrastructure needed for the changing resource mix."[48]

In addition, DOE sets energy policy. Energy Information Administration (EIA), part of DOE, develops generation mix projections to inform DOE and assist with its goals. The Proposed Rule has a direct bearing on grid reliability, which is under the purview of these agencies. Energy markets across multiple jurisdictions will see shutdowns, capacity limitations, and uneven cost burdens, particularly as to utilities and states, like North Dakota, using coal-heavy fuels. Compliance with this rule will have a direct and continuing hold over the energy market through implementation, or at least 2040, with long-lasting indirect impacts from a revolutionized energy conversion. It is beyond EPA's scope and expertise to meddle in energy policy.

These actions lean into FERC's jurisdiction and its delegated authority to NERC. EPA is operating outside its jurisdiction. The dangers of two agencies instituting policy over energy and reliability is problematic. For instance, EIA develops generation mix projections in pursuit of its goals.[49] At the same time, EPA is running IPM models to make the same projections. Preliminary analyses of EPA's model already revealed improper unit retirement projections and undue emphasis on the IRA's financial incentives.[50] These models are completely separate efforts and often do not agree.

Congressional authorizations prevent agency overlapping by designating the agency in charge. EPA must leave energy policy to others. Its BSER selections should allow for all fuel-types to thrive to result in a balanced generation mix. FERC, DOE, and others can then shape the nation's policies per Congress's design.

C. The framework of the Proposed Rule is contrary to CAA Section 111.

The Proposed Rule's structure contradicts the CAA and its Section 111 in several meaningful ways. New source performance standards must be achievable at the unit, usually in the form of an emission limitation. Here, EPA designs a rule with a technology that is not adequately demonstrated (CCS for coal units) or other alternatives based on reduction of capacity factors or retirements. Turning a unit "off" or derating a unit, is not an acceptable BSER – nor has it ever been. EPA should not base coal-fired unit retirement categories on retirement as compliance, nor should Young Unit 1 have to take derates to avoid noncompliance with unrealistic time frames.

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[48] See FERC Strategy Plan for Fiscal Years 2022-2026, Mar. 28, 2022 at https://www.ferc.gov/media/ferc-fy22-26-strategic-plan.
[49] EIA, Annual Energy Outlook 2023, https://www.eia.gov/outlooks/aeo/narrative/index.php#ExecutiveSummary
[50] *See* NRECA Comments and technical support, filed separately in the docket.

Inconsistent availability of BSER to all sources nationwide is not consistent with Section 111. Adequately demonstrated BSER must be dependable and effective to all individual sources at a reasonable cost.[51] EPA may extrapolate but only to a limited degree. In this case, BSER is unequally available. While some geographic areas of the country can support carbon storage, others do not have that option available. Infrastructure is also inconsistent. EPA must re-think its BSER selection and choose a technology that can be uniformly applied.

Natural gas co-firing for intermediate coal-fired units is also not appropriate as BSER for several reasons. First, EPA attempts to address GHG emissions by transforming a coal unit into a natural gas unit. Section 111 does not permit or require "redefining a source" as BSER. In addition, natural gas is not available to all coal-fired units, or it is cost prohibitive to run new gas pipelines to those areas. EPA piles on by only allowing sources to operate until 2040 by conducting a project to co-fire with natural gas. The cost metrics simply do not work to gain only eight more years of operation from 2032 (imminent retirement) to 2040 (beginning of the CCS long-term category) due to less time to amortize the capital costs of this option. Thus, natural gas co-firing as BSER is diverges from the CAA's definition of and application of BSER and should be removed from consideration.

Finally, EPA's shutdown sunset categorization is contrary the historical implementation of Section 111. Subcategories are based on unit size, fuel, or equipment type. Section 111(b)(2) allows EPA to distinguish among classes, types, and sizes within categories of new sources in development of NSPS. The subcategorization for coal-fired units based on the "operating horizon." EPA subcategorizes "like" generating units into categories based on owner/operator plans for utilization. This new concept unlawfully departs from EPA's historic implementation of Section 111 based on the equipment at hand.

VIII. The Proposed Rule erects unduly burdensome Section 111(d) State Plan requirements that remove flexibilities and impose timelines that set up States and sources for failure.

EPA proposes a heavy-handed approach that upsets the cooperative federalism tenets baked into Section 111. EPA restricts state RULOF analyses and places unreasonable timelines in place for state plans.

A. RULOF Analyses must not be eroded.

The Proposed Rule illegally restricts and fails to provide adequate time for state remaining useful life analyses. The Section 111(d) implementing regulations specifically allow for states "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[52] Although EPA has an

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[51] *Essex*, 486 F.2d at 433; *NRDC*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986).
[52] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1) (emphasis added).

opportunity to review the analysis as part of the state plan, this proposal should in no way limit state discretion to consider RULOF for individual sources in the state. EPA justifies narrowing state RULOF determinations by stating that it has "considered impacts on the energy sector as part of its BSER determinations." However, the framework of Section 111 does not mix RULOF into the generalized BSER process. EPA must preserve this individualized analysis that Congress specifically blessed.

States are in the best position to appreciate the contributions of and unique challenges of sources. RULOF in the context of the Proposed Rule may permit states to apply tailored and flexible requirements that will support grid reliability. For example, sources that have foreseeable retirement glidepaths but that are key resources in transmission-constrained areas could be offered a BSER that promotes EPA's carbon reduction goals but falls outside of EPA's one-size-fits-all BSER approach.

B. State plan timelines must be revised.

EPA's state plan timeline does not allow sufficient time for states to engage with affected utilities, conduct new public engagement requirements, develop RULOF analyses, and satisfy the comprehensive plan requirements necessary for EPA approval. State plans are due only 24 months from publication of final emission guidelines, which EPA projects will be April 2024.[53] State plans would be due in April 2026.

The time frame for National Ambient Air Quality Standards state implementation plans under Clean Air Act Section 110(a) is 36 months or three years. EPA likens the Section 111 state plan process to Section 110[54] but departs from the 36-month timeline.[55] Instead, EPA promulgates probably the most complex Section 111 rule of all time. This rulemaking is unlike prior Section 111(d) guidelines that had straightforward emissions limitations. States were able to simply mirror BSER in their plans, as evidenced in 40 CFR Part 62. The Proposed Rule requires states to navigate complex subcategorizations, set emissions limitations, and devise milestones for new technologies. On top of this, RULOF analyses must occur. EPA must provide states with more time.

Sources need more time to make important generation decisions for existing units. EPA is soliciting comment on the compliance date for existing units. The Proposed Rule sets a compliance date of January 1, 2030 but opens the door for an earlier compliance date defined by the date of EPA approval of the state plan.[56] Although EPA sets a 2030 compliance date, state plans will be due much sooner – April 2026 – less than three years from today. Subcategory decisions are likely to be placed

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[53] The Spring 2023 Unified Agenda projects the final rule to be released in April 2024.

[54] Proposed Rule at 33276 ("CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a CAA section 110-like procedure . . . ."); *see* 42 U.S.C. § 7411(d)(1) ("The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan . . . ." (emphasis added).

[55] 87 Fed. Reg. at 79182.

[56] *Id.* at 498.

into state plans with milestones. Sources in actuality must make coal unit sunset decisions much sooner, particularly if they are to avail RULOF flexibilities. Sources would find themselves making premature retirement decisions, while waiting and hoping that CCS, hydrogen technology, and associated infrastructure will catch up to new generation requirements in the Section 111(b) portion of the proposal. It is irresponsible to require utilities to retire generation without a feasible plan to replace it. Such a timeline hedges grid reliability on uncertainties.

Minnkota supports longer state plan development periods, removal of RULOF restrictions, and an existing compliance date that does not require retirement commitments before new generation can be constructed.

IX. Conclusion.

Thank you for your consideration of these comments. Minnkota looks forward to engaging with the Agency concerning this rulemaking. Should you have any questions regarding these comments, please contact Shannon Mikula at 701.795.4211 and smikula@minnkota.com.

Appendix 18

From:	Jeff Jickling <jjickling@saskpower.com>
Sent:	Friday, August 4, 2023 11:49 AM
To:	A-AND-R-DOCKET
Cc:	Darren Foster; Joel Cherry; Cole Goertz
Subject:	Docket ID No. EPA–HQ–OAR–2023–0072: SaskPower Correction of Reference to Boundary Dam Unit 3 Emissions Performance in Proposed Rule
Follow Up Flag:	Follow up
Flag Status:	Flagged

In the Proposed Rule for the *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*, there is a reference to SaskPower's Boundary Dam Unit 3 CCS Facility '*successfully demonstrating the commercial-scale feasibility of 90 percent capture rates*'. As the owner and operator of this facility, we are providing the following correction to the emissions performance of the Boundary Dam Unit 3 CCS Facility.

- SaskPower's CCS facility was the first of its kind, and we have acknowledged the technical issues encountered at the facility, such as amine degradation resulting from fly ash ingress. We have consistently made modifications during the past eight years to stabilize operations, improve reliability and maximize capacity.
- SaskPower's CCS facility is not capturing 90 per cent of emissions from Boundary Dam Unit 3, though that is its nameplate capacity. Our CCS facility has only operated at full nameplate capacity for a few days shortly after it was commissioned.
- To maintain long-term reliable operation, only a portion of the total flue gas from BD3 can be processed by the CCS facility. The portion that cannot be processed through the CCS facility is released to the atmosphere.
- Recent performance has shown that the CCS facility can capture at least 90% of the CO_2 from the partial flue gas stream it processes.
- To ensure a higher level of overall equipment reliability and process efficiency, SaskPower has optimized the CO_2 capture rate at a target of 65 to 70 per cent of total Boundary Dam Unit 3 emissions on an ongoing basis.

If you have any questions, or would like further information, please contact Jeff Jickling at (306)566-2374 or jjickling@saskpower.com.

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Appendix 19

Technical Comments on the

Carbon Capture Utilization and Sequestration Aspects of the Proposed

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

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National Rural Electric Cooperative Association

August 7, 2023

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1 Summary

The U.S. Environmental Protection Agency (EPA) on May 23, 2023 proposed five separate actions under Section 111 of the Clean Air Act addressing greenhouse gas emissions (GHG) from fossil fuel power plants generating electrical power. EPA bases the proposed GHG rule on many unverified assumptions, but the most egregious is that carbon capture utilization and storage (CCUS) is a demonstrated technology and qualifies as best system of emission reduction (BSER). EPA (improperly) designates CCUS as BSER, then extrapolates CCUS cost metrics to a wide variety of generating units. That EPA uses questionable means to generalize CCUS cost is of concern, but such concern is secondary to the unsubstantiated claim – and flaw in EPA's proposal - that CCUS is BSER. Consequently, all CCUS-related cost and performance predictions fail.

This critical observation, supplemented with several others, is further described as follows:

The CCUS Utility experience base is inadequate.

There is a single CCUS process operating in North America relevant to utility power generation—Sask Power Boundary Dam Unit 3. This unit has operated since 2014, and over eight years of refinement exhibits increased reliability– which although improved can still be compromised by failure of specialty, hard-to-acquire components that cannot be readily "spared" on-site.

A second CCUS operating unit relevant to utility power application – the Petra Nova "slipstream" project at the W.A. Parish station - operated for three years before termination in March of 2020. As further discussed in Section 3, both demonstrations were significantly co-funded by federal (and for Sask Power Boundary Dam) the local (provincial) governments.

This collective large-scale CCUS experience – comprised of two units with one operating for an abbreviated period – does not reflect the variety of conditions for CCUS application to the U.S. generating fleet. Of particular note is that small-scale pilot plant tests for two proposed demonstrations – conducted in 2015 (Minnkota Power Milton R. Young) and presently ongoing (Basin Electric Dry Fork) and are necessary to address remaining risk. The lean CCUS experience is in sharp contrast to real-world lessons accumulated in the early- and mid-70s with first-generation flue gas desulfurization (FGD) technology, in which 20 generating units were equipped with FGD and operated (some for five years) prior to a federal mandate to limit sulfur dioxide (SO_2) emissions.

Industrial CCUS applications are inadequate to reflect utility power generation.

EPA cites numerous industrial applications that due to scale, effluent gas treated, atypical CO_2 content and process conditions, limited removal of CO_2, or intermittent operation, are of

peripheral import to coal-fired utility application. Consequently, experience with industrial applications has no impact on qualifying CCUS as utility-scale BSER.

Engineering "FEED" studies – regardless of the detail – do not deliver real-world operating experience, and are not a substitute for "lessons learned" from authentic operation.

EPA, lacking relevant CCUS experience, cites up to 15 engineering (Front-End Engineering Design, or FEED) studies as a basis for BSER. EPA's premise is invalid for two reasons. First, FEED studies do not address "final" design – the latter exercise a separate step, prior to equipment procurement. Second, and more important, FEED studies are exclusively paper and digital exercises that do not include the critical follow-through of building, operating, and documenting experience that almost without exception leads to revised design.

This view is shared by two contractors that supported EPA in this rulemaking. Sargent & Lundy Engineers (S&L) and Bechtel National Corporation state CCUS FEED studies leave risks that are not addressed. Specifically, EPA sponsored S&L to develop model CCUS cost calculations referenced in the Technical Support Documents, which state CCUS is an evolving technology. Bechtel, prime contractor for the FEED study addressing CCUS retrofit to the Panda/Sherman natural gas/combined cycle (NGCC) generating unit, state the present level of CCUS experience is inadequate; they recommend – prior to full-sale application at Panda/Sherman – a large capacity pilot plant test be conducted.

The CCUS cost basis – both capital requirement and the levelized cost per ton ($/ton) to avoid CO2 - is highly uncertain, and will remain so without additional large-scale demonstrations.

EPA attempts to compensate for the lack of experience by featuring paper and digital calculations, derived from unverified FEED studies, to determine the cost to avoid CO_2 ($/tonne).[1] The shortcomings for coal and NGCC applications differ, and are described separately.

Coal Applications. First, EPA – although citing FEED studies as a basis for BSER – ignore them as a source of capital cost for actual sites. Alternatively, EPA uses capital costs for a hypothetical unit, as determined by the National Energy Technology Laboratory (NETL) of the Department of Energy (DOE). A more authentic cost would be derived from the "average" of the six FEED studies – that even with uncertainty is "grounded" by actual site specifics. The difference in cost is not small - EPA's selected hypothetical unit capital cost is approximately 30% less than the average of the six FEED studies.

Conversely, EPA, when seeking estimates of cost to avoid CO_2 ($/tonne basis), changes course and features the FEED studies ignored for capital cost. EPA highlights FEED study results - along with several from international studies – to showcase that cost to avoid a tonne of CO_2 ($/tonne) cluster near the research and development (R&D) target of $40/tonne. As previously described, FEED results are paper and digital exercises, describing facilities never built or tested.

[1] All references to avoided cost are cited in terms of cost per metric tons ($/tonne).

Further, key factors that drive the levelized cost result – capacity factor and remaining unit lifetime – are not presented. EPA's reporting of these costs is not transparent.

NGCC Applications. Similar to the case for coal duty, EPA ignores FEED studies as a source for CCUS capital. EPA again defers to an NETL study of a hypothetical unit for capital cost – but not really, as EPA "discounts" the capital inferred. Specifically, EPA determines CCUS capital cost per net power output – the conventional metric - by normalizing the CCUS cost by net power *generated prior to CCUS*. This unusual combination – normalizing CCUS cost by net power *prior to retrofit* – is unprecedented, and ignores the loss of 33 MW consumed by CCUS. No explanation is offered for what is effectively a discount.

In summary – for both coal-fired and NGCC application – CCUS costs remains highly uncertain.

EPA's projected schedule for CCUS deployment – from concept evaluation to injection of CO_2 for sequestration or enhanced oil recovery – is unrealistic and compressed even compared to optimistic projects.

EPA ignores schedules to retrofit CCUS issued by two sources: the contractor S&L whom they engaged for this purpose, and the Global CCS Institute. S&L developed for EPA a CCUS retrofit schedule describing 6.25-7 years as necessary, and concede this applies to a partial scope of duties by ignoring CO_2 transportation (e.g. pipeline construction and permitting) and terrestrial sequestration (e.g. site development and permitting). The Global CCS Institute cites almost nine years as necessary, but "pass" on realistic permitting challenges – by noting their schedule assumes ".... there is no significant community opposition" to the project. Experience in the U.S. particularly the Midwest – belies this assumption.

EPA assumes the responsibility of completing the schedule. EPA adds activities to S&L's scope but compress the schedule by about two years. The resulting five-year schedule – slightly more than half of the 8.25 years advised by the Global CCS Institute - allocates one half-year to for CO_2 "transport and storage" feasibility and two years for CO_2 sequestration "site characterization and permitting." These estimates are contrary to plentiful evidence such timeframes are not credible. Section 5 describes how acquiring a CO_2 pipeline permit – such as the proposed Navigator project in Iowa - appears to require 3.5 years and only if no other roadblocks emerge prior to end-of-year 2024. Section 6 summarizes detailed schedules developed for the FEED studies and show under ideal conditions – a "head-start" for sequestration site development and no barriers to CO2 pipelines – eight years are required. Some projects will require possibly 12 years.

These studies suggest not only that the five-year time frame is unrealistic, with 10 years or more required for many projects.

CCUS does not qualify as BSER.

EPA is to select BSER after considering if a technology is "adequately demonstrated", "commercially available," and can be deployed for a cost that is "reasonable", all while representing the best balance of economic, environmental, and energy considerations. Two utility demonstrations – both with significant government cofunding – do not comprise an adequate demonstration. Process equipment for CCUS can be purchased – but without meaningful guarantees from process supplier, the technology is not fully commercially available. Costs, projected mostly from paper and digital FEED studies, are highly uncertain.

CCUS is distinguished from all precedent environmental controls in that a significant fraction of power produced that would be directed to the grid – 20-30% for coal- and 10% for NGCC-application – is consumed by the process. This collection of conditions does not qualify CCUS as BSER in the present state of development.

2 INTRODUCTION

The U.S. Environmental Protection Agency (EPA) on May 23, 2023 proposed five separate actions under Section 111 of the Clean Air Act addressing greenhouse gas emissions (GHG) from fossil fuel power plants generating electrical power. New Source Performance Standards (NSPS) for stationary combustion turbines and coal-fired generating units to limit emissions of CO_2 are proposed, as well such limits for existing fossil fuel generating units fired by coal, or gas turbines operating in simple or combined cycle duty.

Of the elements of EPA's proposed regulation, there is one critical premise – the role EPA assigns to carbon capture utilization and storage (CCUS). EPA submits that CCUS – in the present state-of-art technology –is commercially proven and feasible for utility application to both coal-fired and natural gas combined cycle (NGCC) generating units. EPA projects via its Integrated Planning Model (IPM) that 39 coal-fired power plants – totaling almost 14 gigawatts (GW) of capacity – will adopt CCUS by 2030.[2] The premise of EPA's modeling results in arbitrarily determining that CCUS is the best system of emissions reduction (BSER).

This report addresses the technology status of CCUS in terms of designation as BSER. The operating experience to underpin future applications of CCUS technology is reviewed, considering commercial-scale duty, laboratory tests, and the paper or digital design studies funded by the National Energy Technology Laboratory (NETL) and others.

This report is comprised of seven sections and two appendices. Section 3 addresses the shortcomings with industrial experience and Front-End Engineering and Design (FEED) studies, the features of emerging technology, and the limited experience with two units equipped with CCUS. Section 4 reviews EPA's evaluation of CCUS cost, addressing capital required and the levelized cost to avoid CO_2 on a dollar per metric tonne basis ($/tonne), including the impact of tax benefits accrued through the Inflation Reduction Act (IRA). Section 5 highlights one aspect of CCUS EPA does not address in detail – the task of securing CO_2 pipelines for delivery to sites for sequestration or use for enhanced oil recovery (EOR). Section 6 addresses EPA's assumption that a five-year deployment schedule is realistic. Section 7 projects on a continental map of North America the locations of EPA projected CCUS applications, showing the relationship to existing and proposed CO_2 pipeline routing and potential geological sequestration or EOR sites. Select backup material is presented in Appendices A and B.

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[2] U.S. EPA, *Integrated Proposal Modeling and Updated Baseline Analysis, Memo to the Docket* (EPA_HQ_OAR_2023_0072), July 7, 2023. Hereafter EPA 2023 Integrated Baseline Analysis.

3 CCUS EXPERIENCE RELEVANT TO BSER

The EPA has designated CCUS as BSER based on the following rationale:

The technology has been studied, examined, and tested for decades and it has reached a point in its development where it is adequately demonstrated and commercially available.[3]

The additional economic incentives are important for establishing that the cost of CCS is reasonable, and an appropriate BSER.[4]

Section 3 reviews the technical basis of CCUS, focusing on relevant utility power generation experience, considering the definition of technology as adequately demonstrated and commercially available, and the incurred cost.

It should be noted EPA does not propose criteria by which to gauge CCUS in terms of the metrics "adequately demonstrated", "commercially available", and a cost that is "reasonable", and "appropriate." Nor does EPA address the decision to select a technology with the "best" balance of economic, environmental, and energy considerations.

3.1 Criteria for "Adequately Demonstrated"

A technology is considered "demonstrated" when there is (a) adequate experience that reflects projected operating duty, (b) confidence that operation is reliable over extended periods of time, and (c) the technology suppliers can *offer meaningful guarantees,* more than equipment and engineering services for sale. EPA in several instances distorts the meaning of the term "demonstrated". Most notable are (a) application at industrial or small-scale processes, and (b) the significance of engineering studies, the latter without corroborating results. These are described as follows:

3.1.1 Industrial Applications

EPA submit that industrial application of CCUS – particularly for cases that "report" 90% CO_2 capture – contribute to demonstrating CCUS for utility applications.

Industrial applications significantly differ from utility-scale power generation. Utility applications are distinguished by continual 24 x 7 duty, operation at high reliability, and processing flue gas with CO_2 content that differs from utility power generation – the latter typically 3-4% CO_2 for NGCC application and 11-13% CO_2 content for coal-fired application. Almost all non-utility applications treat product gases with higher CO_2 concentrations – such as

[3] Greenhouse Gas Mitigation Measures for Steam Generating Units – Technical Support Document. Docket EPA-HQ-OAR-2023-0072. Page 35. Hereafter Steam EGU TSD.
[4] Ibid.

chemical and ethanol production, and processing of hydrogen and ammonia, by up to a factor of 10. These high concentrations of CO_2 elevate the "driving force" for mass transfer and adsorption, which combined with a smaller scale and shorter physical distance over which to effect mixing and CO_2 absorption present different challenges than for power generation.

EPA's industrial "reference applications" are not relevant to utility duty. Specifically, EPA claims CCUS viability is "*.... further corroborated by CO2 capture projects assisted by grants, loan guarantees, and Federal tax credits for "clean coal technology" authorized by the EPAct05. 80 FR 64541–42 (October 23, 2015).*"[5] EPA cite a compilation of 72 CCUS projects – demonstration tests, pilot plant test, CO_2 storage, and transport activities – as relevant supporting their assessment, per Excel file "Attachment_1",[6] of which only two treat the entirety of gas flow generated. These two facilities – the Searles Valley Minerals caustic soda plant and the Quest methane reformer – do not represent large-scale utility duty, nor is there evidence that CO_2 removal matched that proposed by EPA for 24x7 duty. Other sites referenced by EPA are the "slip stream" category of process testing for which CCUS reliability does not limit that of the host unit.[7] Two "slip-steam" tests cited in the "Attachment 1" reference file are discussed – the Bellingham Energy Center for NGCC duty, and the Petra Nova demonstration (discussed in Section 3.3).

The sites reported to process the entirety of product gas – Searles Valley Mineral and Quest – are further described as follows:

Searles Valley Minerals. Public information suggests CO_2 capture is either intermittent or derives CO_2 removal well below 90%. The Searles site is comprised of three coal-fired units – two generating 27.5 MW and a third at 7.5 MW.[8] The CO_2 removal capability is cited as 800 tons per day[9] which suggests relaxed duty. Specifically, if the CO_2 removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of CO_2 per day – and daily CO_2 removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% CO_2 removal for 35% operating time (perhaps one "daytime" shift). These performance metrics are not adequate to qualify CCS as demonstrated technology.

Quest. The effluent from this methane reforming process does not reflect combustion products, as CO_2 content is elevated compared to utility application. Experience with CO_2 removal at highly elevated content – although contributing to general CCUS knowledge – is not a basis to designate CCUS as BSER for utility application.

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[5] Steam EGU TSD. Page 22.
[6] EPA-HQ-OAR-2023-0072-0061_attachment_1.
[7] Three additional facilities are listed as operating CO2 capture, but as a "slipstream'. (AES Warrior Run, AES Shady Point, and Bellingham Energy Center). The slipstream process arrangement – a useful means for research and development - does not link the reliability of the host process to the CO_2 capture technology – and thus cannot represent conditions for 24x7 utility power generation demonstration.
[8] Energy Information Agency 860 Data, File 3_1_Generator_Y2021. Operable tab, Rows 9148-9150.
[9] Elmoudir, W. et. al., *HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA*, Energy Procedia 63 (2): 6156-6165, December 2014.

Bellingham Energy Center. This NGCC unit is host to a 40 MW slip-stream employing a first-generation amine-based process (that evolved as the Flour Econoamine process). There is no data available to describe these results – a DOE "fact sheet" reports the unit operated from 1991 through 2005, with CO_2 removal of "85-95%".[10] It is not known if operation was continual versus intermittent, pending market demand for commercial grade CO_2. If periods of 85-95% CO_2 removal are interspersed with lower targets, this experience does not support BSER for utility application.

In summary, experience with industrial CCUS applications, although contributing to CCUS technology evolution, does not qualify CCUS as demonstrated for utility duty.

3.1.2 Engineering FEED Studies

EPA claims studies of CCS feasibility for utility duty – "Front End Engineered Design" or FEED studies – contribute to designating the technology as "demonstrated".

Three phases of analysis are typically employed to develop a CO_2 capture design. The first step defines the overall features of the design, using general site information, and "budgetary" cost quotations. This "pre-FEED" study presents a feasibility "yes/no" test.

The second step – the FEED study – is intended to (a) develop in more detail process flowsheets and/or equipment arrangement drawings, and (b) solicit budgetary quotations from suppliers to establish cost and availability. Some FEED studies include a construction plan, addressing the fabrication and delivery of the largest components to the site. At present, there are 13 such complete FEED studies (listed in Section 5) addressing coal-fired and NGCC generators.

The third phase is detailed engineering which specifies equipment physical attributes, layout, and an operating plan in detail to develop a request for proposal and solicit a supplier "firm" designs and cost. This detailed engineering step has been completed only for the Sask Power Boundary Dam 3 and the Petra Nova projects. For developed technology, this third phase should solicit performance and/or reliability guarantee from equipment suppliers.

EPA cite four FEED studies for coal and three for NGCC,[11] with seven more planned described in Attachment _1.[12] EPA rightfully identifies these FEED studies as "...projects in the early stages of assessing the merits of retrofitting coal steam EGUs with CCS technology", with potential for "...the application of CCS to existing gas facilities".[13]

[10] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. Available at https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.
[11] Steam EGU TSD. P. 23.
[12] EPA-HQ-OAR-2023-0072-0061_attachment_1.
[13] Steam EGU TSD. P. 23.

As will be shown for several projects, there remain significant "post-FEED" details in design and specifications for procurement. Most importantly, FEED studies as paper and digital exercises are absent the critically important "learning by doing" – the frequently quoted guidance from the Global CCS Institute as necessary to evolve CCUS.[14]

Four FEED studies are cited in the Steam EGU TSD for coal-fired duty: Basin Electric Dry Fork, Prairie State Generating Station, the Milton R. Young Station of Minnkota Power, and Nebraska Public Power District's Gerald Gentleman Station. Each of these studies is complete and project CCUS capital cost, and with assumptions of unit lifetime and capacity factor project an implied cost to avoid CO_2 ($/tonne). Capital cost results from these projects – in addition to analogous studies addressing Enchant Energy San Juan and Sask Power's Shand station – are addressed in Section 4.

Four newly launched studies have not progressed to delivering cost estimates. These are Cleco Brame Energy Center Madison Unit 3 (pet coke/bit coal) (Lena, LA); Duke Energy's Edwardsport integrated gasification combined cycle (IGCC) facility (Edwardsport, IN); Four Corners Station (located on the Navajo Nation in AZ); and CWL&P Dallman Unit 4 (Springfield, IL).

FEED studies are important - but on their own – are inadequate to qualify a technology as commercial. In at least two instances, FEED study authors advised additional pilot plant testing.

Basin Electric Dry Fork Coal-Fired. A 2020 FEED study by S&L evaluated MTR's membrane CO_2 capture technology for application to the Basin Electric Dry Fork station, and had advised the next phase of activities a 10 MW "large" pilot plant test,[15] evolving to a "slip stream" configuration for "partial capture conditions" at 400 MW capacity. This advisement offered in 2020 is testament to the evolving nature of CCUS technology.

NGCC Combined Cycle. A FEED study conducted by Bechtel National examined retrofit of a generic monoethanolamine (MEA) process to the 758 MW Panda Sherman Power Project. The principal investigators noted: *"At the time of this FEED study, no full-scale NGCC power plants with PCC was built anywhere in the world; even pilot studies using NGCC flue gas conditions were limited. This leads to a lack of data for process simulation model validation under conditions of interest for commercial NGCC+PCC plants…. ".*[16]

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[14] Technology Readiness and Cost for CCS, Global CCS Institute, March 2021. Available at https://www.globalccsinstitute.com/resources/publications-reports-research/technology-readiness-and-costs-of-ccs/.
[15] Freeman, B. et. al., Commercial-Scale FEED Study for MTR's Membrane CO2 Capture Process, presentation to the Carbon Capture Front End Engineering Design Studies and CarbonSafe 2020 Integrated Review Webinar, August 17-19, 2020. P. 23.
[16] Elliot, W.R. et. al., *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),* Final Scientific/Technical Report, DE-FE0031848, March, 2022. P. 2. Hereafter Panda Sherman 2022 Final Report.

The principal investigator then concludes: *"A pilot testing program is therefore proposed to resolve most of these design uncertainties, generally duplicating all process elements of the full-scale PCC unit apart from CO2 product compression."*[17]

This is S&L's second advisement that CCUS is emerging technology – in addition to recommending a pilot plant test at Dry Fork prior to commercial demonstration, S&L describe the technology as "emerging" in an explanatory note issued with the proposed CCUS schedule.[18]

FEED Studies are critical to project development for CCS as this technology is an emerging technology with very limited full-scale / commercial installations.

In summary, FEED studies develop the arrangement of process equipment and preliminary cost for CCUS. These conceptual exercises are inadequate to qualify CCUS as BSER.

3.2 Stages of Emerging Technology

Commercially available technologies are characterized by operating experience that enables process suppliers to provide meaningful performance guarantees.

As noted by S&L, CCS is considered an "emerging technology"[19] which typically evolve in several stages. Early projects are based on limited experience and the role of process suppliers evolved during this period. It must be emphasized there is stark contrast between a supplier offering "for sale" an engineered design and fabricated hardware, in contrast to providing meaningful process guarantees. This subsection further addresses these topics.

3.2.1 First, Nth-of-a-Kind

Any new process – or application of an evolving process to conditions outside present-day experience – is considered the "first" of a "kind" (FOAK). Such FOAK designs are characterized by uncertainty in terms of equipment arrangement, process conditions (reaction chemistry, flow field, temperature), and operating duty, and the risk to achieve environmental control performance and reliability.

FOAK designs can address risk and uncertainty but only by large scale testing and operation for extended periods. Projects subsequent to FOAK are described as the "Nth-of-a-Kind" (NOAK), in which additional (the nth) application addresses evolving conditions. There is no clear delineation between the number of FOAK applications necessary to evolve to NOAK.

Power industry technologies are not considered "demonstrated" until adequate "NOAK" applications operate for sufficient time, defining and resolving uncertainties. There is no broadly recognized threshold for the number of acceptable NOAK projects to be completed prior to

[17] Ibid.
[18] S&L_CCS_Schedule_EPA-HQ-OAR-2023-0072-0061_attachment_16.pdf.
[19] Ibid.

commercial maturity. The DOE acknowledges this uncertainty with regard to CCUS, in noting NOAK designs can include equipment that ".... are not fully mature (e.g. plants with IGCC and any plant with CO_2 capture…", and will incur costs higher than reflected within their most recent analysis.[20]

The fact that CCUS is a FOAK or NOAK is evidenced by the demonstrations at the Basin Electric Dry Fork and Minnkota Power Milton R. Young station. As described in Section 6, the site-specific process design for these sites relies heavily on pilot plant tests – either completed (in 2015) or presently underway – at the site. The uncertainties which remain are best addressed at pilot scale which is proof CCUS technology is not mature.

The uncertainty of FOAK designs is also recognized in the Princeton "Net-Zero" study.[21] The analysis suggests five FOAK designs must be built and operated for – in their opinion – sufficient time for costs to "settle"; but with broader implications for mitigating risk.

3.2.2 Commercially Availability

EPA implies CCUS processes are commercially available when suppliers offer to sell the necessary process equipment and engineering services. However, a supplier offering to design, procure and install such hardware does not constitute commercial availability. The missing requirement is meaningful guarantees of process performance, backed with remedial action if goals for emissions removal or reliability are not attained.

Neither Sask Power or Petra Nova process hardware were reported as awarded performance guarantees. That absence of commercial guarantees is the reason both projects were significantly co-funded by federal and local governmental entities, with additional funds defraying risk inherent to a FOAK concept.

3.3 North American Utility Scale Processes

At present, there is one operating CCUS unit in North America from which to assess commercial feasibility – Sask Power Boundary Dam Unit 3. A second CCUS-equipped unit – Petra Nova – operated for 3 years (terminating in March 2020). Both of these demonstrations provide significant experience – but on their own does not establish CCUS as demonstrated and commercially available.

A summary of these two projects is presented in this subsection.

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[20] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL – 2023/4320, October 14, 2022. Hereafter 2020 Baseline CCUS Costs. P.50
[21] The Princeton Net-Zero Project - *Potential Pathways, Infrastructure, and Impacts.* Available at https://netzeroamerica.princeton.edu/?explorer=year&state=national&table=2020&limit=200

3.3.1 Sask Power Boundary Dam 3

Overview. Sask Power has operated CCUS at Boundary Dam Unit 3 since 2014, employing an early generation Cansolv CO_2 process. Inherent to the Cansolv process is a SO_2 removal step – controlling SO_2 to less than 10 parts per million (ppm) – that combined with improved particulate matter control protects the amine sorbent from degradation.

This activity was significantly co-funded by the Canadian and Saskatchewan provincial governments. The capital budget is approximately $1.2 B (USD), of which $240 M is provided by the Canadian and provincial government. The retrofit of CCUS was contemporaneous with refurbishing the steam turbine and the electric power generator to support 30-year operation.

CO_2 Disposition. CO_2 is compressed to 2,500 pounds per square inch gauge (psig) and transported 70 kilometers (km) by pipeline to the Weyburn oilfield for EOR, where it is injected 1.7 km underground. CO_2 not employed for EOR is transported 2 km for sequestration in the Deadwood saline aquifer (referred to as Aquistore).

As the Steam EGU TSD notes, a key issue is protecting the amine sorbent from decay with exposure to trace metals and SO_2. Several issues not unique to CCUS process equipment have compromised reliability. EPA note CCUS reliability was compromised in 2Q 2021 due to a failed CO_2 compressor but dismiss this as not inherent to CCUS reliability. However, Sask Power cites these large, special purpose components as rare, and due to limited inventory are not immediately accessible. The cost to maintain "spares" on site is prohibitive. To assure high reliability, additional capital cost should be allocated to provide access to spare equipment; alternatively, enhanced operation and maintenance (O&M) should be planned and include downtime for "preventive" maintenance.

Observations are offered for Sask Power Boundary Dam 3 in three categories: reliability, cost of CO_2 capture ($/tonne), and implementation schedule.

Reliability. The availability of the Boundary Dam 3 CCUS facility is publicly reported in the Sask Power's CCUS Blog.[22] This latter source reports the reliability separately of the host boiler and CCUS process since Q1 2021. Figure 3-1 presents two quarterly reports that describe reliability continuously from Q1 2020 through Q1 2023 (available as of July 24, 2023). The top portion of each chart reports Boundary Dam Unit 3 availability (white background) and the lower portion of each chart reports CCS facility availability (gray background).

Considering CCS facility alone, Figure 3-1 shows the average of availability from Q2 2021 through Q1 2023 is 64.5% over this period. The loss of the compressor is a major contributor to this shortfall and a factor to be encountered in commercial duty.

[22] https://www.saskpower.com/about-us/our-company/blog/2023/bd3-status-update-q1-2023.

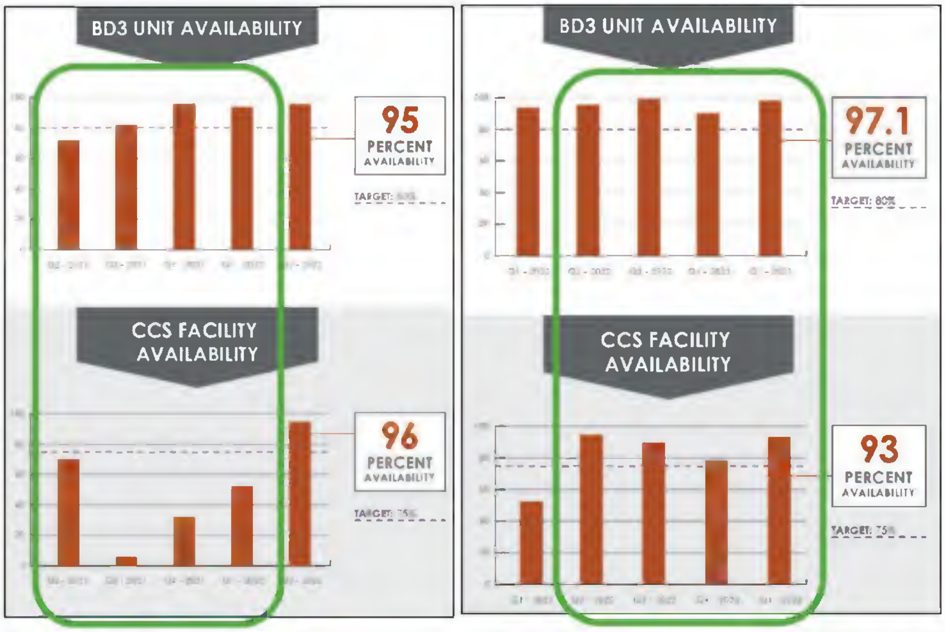

Figure 3-1. Reliability of Boundary Dam Unit 3, CCS Process: Q1 2021 to Q1 2023

Cost. As a FOAK retrofit, Boundary Dam 3 cost although not representative is informative. As previously described, capital cost (including plant refurbishment was of \$1.2 B (U.S, 2014-dollar basis),[23] with the Canadian government contributing \$240 M.[24]

Sask Power report 50 percent of the cost is attributable to the CO_2 capture and regeneration process, 30 percent for power plant refurbishment, and 20 percent for other emissions control and other efficiency upgrades.[25] Consequently, \$600 M of capital is accounted for CCUS, equivalent to \$5,405/kW $_{(net,\ w/CCUS)}$.

The levelized cost to avoid one tonne of CO_2, as reported by the CCS Knowledge Center, is \$105. This cost estimate is based on a capacity factor of 85 percent, lifetime of 30 years, and a credit for CO_2 as EOR.[26] It should be noted CCUS availability since 1Q 2021 has prevented this cost of \$105/tonne from being achieved.

[23] https://financialpost.com/commodities/energy/jim-prentice-to-wind-down-carbon-capture-fund-in-alberta-new-projects-on-hold?. Canadian dollar values at 0.86 USD in 2014.
[24] See: https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/.
[25] Giannaris et. al. 2021.
[26] *The Shand CCS Feasibility Study Public Report*, November 2018, CCS Knowledge Center. Available at https://ccsknowledge.com/initiatives/2nd-generation-ccs---Shand-study. Hereafter Shand 2018 Feasibility Report.

Schedule. Sask Power does not report schedule details from concept inception to delivering CO_2 for EOR, but reports the project took six years from "…commitment to completion".[27] Given the proximity to both an existing oil field (Weyburn) and saline reservoir (~10 mile) the actions to acquire permits – not reported by Sask Power – are likely atypical for most of the U.S. domestic fleet.

Sask Power's schedule may be relevant only for units situated in oil producing regions. Considering the cost subsidy, the reliability issues, and the incurred cost of CO_2 control, Boundary Dam 3 experience does not represent CCUS as "adequately demonstrated" or "commercially available."

3.3.2 Petra Nova

Overview. NRG, owners of the W. A. Parish Generating Station, operated the Petra Nova CCUS process at Unit 3 from March 2017 through March 2020. This process employed the second-generation KM-CDR solvent developed by MHI and Kansai Electric Power Company, previously tested at 25 MW scale at Alabama Power Company's Barry Station.

The Petra Nova demonstration, significantly co-funded by the U.S. DOE, required capital of approximately $1 B. The CCUS process is not applied to the entirety of Unit 3 flue gas, but rather a 240 MW-equivalent slipstream, thus not affecting host unit reliability. Petra Nova's CCUS process hardware is unique – a 78 MW gas turbine (GE 7FA) was installed with a heat recovery steam generator (HRSG), the latter the source for CCUS auxiliary steam. The power generated by the gas turbine not consumed by the CCUS process (reported as 35 MW) is sold to the energy grid.[28]

CO_2 Disposition. CO_2 upon regeneration is compressed to 1,900 psig and transported 81 miles by pipeline for EOR at the West Ranch site, requiring injection between 5,000 feet to 6,000 feet underground. Unlike Boundary Dam Unit 3, there is no alternative means of CO_2 disposition.

Similar to Boundary Dam Unit 3, numerous operating issues were encountered with ancillary components. Heat exchangers processing reagent denoted as cool lean (without CO_2) and hot rich (with CO_2) were prone to leaks, while the gas quencher accumulated deposits that restricted performance. Some issues are attributed to penetration of SO_2 entering the capture process. These components are necessary for CCUS, and their failure should not be dismissed as incidental. In the third operating year, additional factors such as tube corrosion in the solvent reclaimer were encountered that – similar to Sask Power – can compromise CO_2 compressor performance.

[27] SaskPower's Boundary Dam Carbon Capture Project Wins Powers Highest Award, Power, https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/.
[28] W.A. Parish Post-Combustion CO_2 Capture and Sequestration: Demonstration Project DOE Award Number DE-FE0003311 Final Scientific/Technical Report, Report DOE-PNPH-03311, March 31, 2020. Hereafter Petra Nova 2020 Final Report.

Observations are offered for the Petra Nova project in three categories: Reliability, cost of CO_2 capture ($/), and implementation schedule.

Reliability. CCS reliability increased each year. Considering both the CO_2 capture system and the source of auxiliary steam, in the last operating year (2019) 49 days were fully or partially lost. Although an improvement from the 108 observed in 2017, the CCUS process was still not available for 13.4% of operating time in the third and best year.

Cost. Petra Nova reports a $1B capital cost with approximately 60% expended for the CO_2 capture equipment, gas turbine, and the HRSG – the latter to provide auxiliary steam. The remaining approximately 40% of the cost was dedicated to administrative matters, the share of the CO_2 pipeline, and improvements to the oil field to enable higher CO_2 injection for EOR. Funding sources were a DOE grant of $190 M, financing of $250 M, and equity offered by the sponsors. One trade journal noted Petra Nova financing conditions were unique: "Like other early CCS demonstration projects, Petra Nova's financial viability relied on a rare alignment of incentives, including a DOE grant, cheap credit from Japan, and part-ownership of an oilfield, which probably has limited relevance for future CCS plans under the new fiscal policy."[29]

The project sponsors are not forthcoming with actual incurred cost per tonne ($/tonne). The final report to DOE[30] does not address this cost metric. The EPA in the Steam EGU TSD cite a cost of $65/tonne, as referenced to the Global CCS Institute,[31] whom in turn cite a Petra Nova Technical Report from a period (July 2014 through December 2016) prior to unit operation.[32] Consequently, the $65/tonne is a pre-operational estimate, no different than a FEED evaluation, for which basic parameters of unit lifetime and capacity factor are not shared. Also, project economics should account for the incremental revenue derived from the 35 MW delivered by the gas turbine (acquired under the CCUS budget) to the grid. (This revenue could lower CCUS levelized cost, but no details are provided.

Schedule. Petra Nova required a 6-year schedule for their activities, with work initiating in early 2011 to enable an air permit to be filed in September 2011,[33] although details are absent in the public schedule.[34] Petra Nova is unique as the Texas Gulf Coast provides an ideal location for CCUS given existing pipeline corridors and proximity of oilfields that can readily accept significant CO_2 injection.

[29] https://www.nsenergybusiness.com/features/petra-nova-carbon-capture-project/#.
[30] Petra Nova 2020 Final Report.
[31] Technology Readiness and Costs of CCS, March 2021, the Global CCS Institute. See page 35.
[32] W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Topical Report/Final Public Design Report, Award No. DE-FE0003311, for July 01, 2014 to December 31, 2016. See page 30.
[33] Ibid. P. 13.
[34] *Petra Nova Carbon Capture*, presented to the Carbon Capture, Utilization and Storage, and Oil and Gas Technologies Integrated Annual Review Meeting, August, 2019. Graphic 3. Available at: https://netl.doe.gov/sites/default/files/netl-file/Anthony-Petra-Nova-Pittsburgh-Final.pdf.

The Petra Nova project schedule may be relevant only for units situated in oil producing locales. Considering the cost subsidy required, and complicated by reluctance to release the final costs, the Petra Nova project – although contributing to CCUS technology development - does not qualify CCUS as BSER.

4 REVIEW OF EPA's PROJECTION OF CCUS COST

4.1 Overview

Section 4 critiques EPA's cost evaluation of CCUS. As noted in Section 3, there are only two verified capital cost reports for CCUS –Sask Power Boundary Dam Unit 3 and Petra Nova. EPA's proposed trajectory of CCUS evolution more optimistic compared to that observed for flue gas desulfurization (FGD) technology, in which multiple demonstration tests (many <100 MW) operated for up to 5 years prior to federal legislation mandating FGD deployment. Further, EPA is inconsistent in their selection of references – after lauding FEED studies that EPA submits demonstrate the technology as commercial – EPA ignores these results when seeking capital cost. Finally, EPA does not consider the risk to reliability presented by CCUS, that compromises CO_2 removed and tax benefits accrued through the IRA.

These are further described as follows.

4.2 Inadequate Experience for Cost Basis

There is little verified experience with CCUS to base EPA's estimate of cost. In contrast, FGD evolved through approximately 20 commercial-scale processes that provided significant experience at utility conditions, prior to federal legislation mandating their use.

Figure 4-1 presents for FGD technology the installation date and flue gas equivalent generating capacity treated for installations through mid-1978. It should be noted that 20 FGD installations were installed and operating prior to the 1977 Clean Air Act Amendments - with at least 10 operating for up to five years.[35] This experience served as the basis to mandate the use of FGD.[36]

Figure 4-1 shows that – prior to 1977 and drafting of the Clean Air Act Amendments in that year – FGD technology evolved in a logical manner. The first three years (through 1975) saw 10 installations, of which all but three were of 150 MW of capacity or less. Notably, three installations that exceeded 400 MW in capacity were an early design variant – the "combined particulate/SO_2" process – which incurred either reliability or SO_2 removal challenges. These combined particulate/SO_2 processes – almost without exception – required refurbishment or replacement with "conventional" limestone FGD technology.

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[35] Shattuck, D. et. al., *A History of Flue Gas Desulfurization (FGD) – The Early Years*. Available at https://www.science.gov/topicpages/g/gas+desulphurization+fgd.

[36] Aldy, J. E. et. al., *Looking Back at Fifty Years of the Clean Air Act*, Resources for the Future Report 20-01 October 2020, Revised December 2020. Available at: https://media.rff.org/documents/WP_20-01_rev._Looking_Back_at_Fifty_Years_of_the_Clean_Air_Act_hmvW55y.pdf.

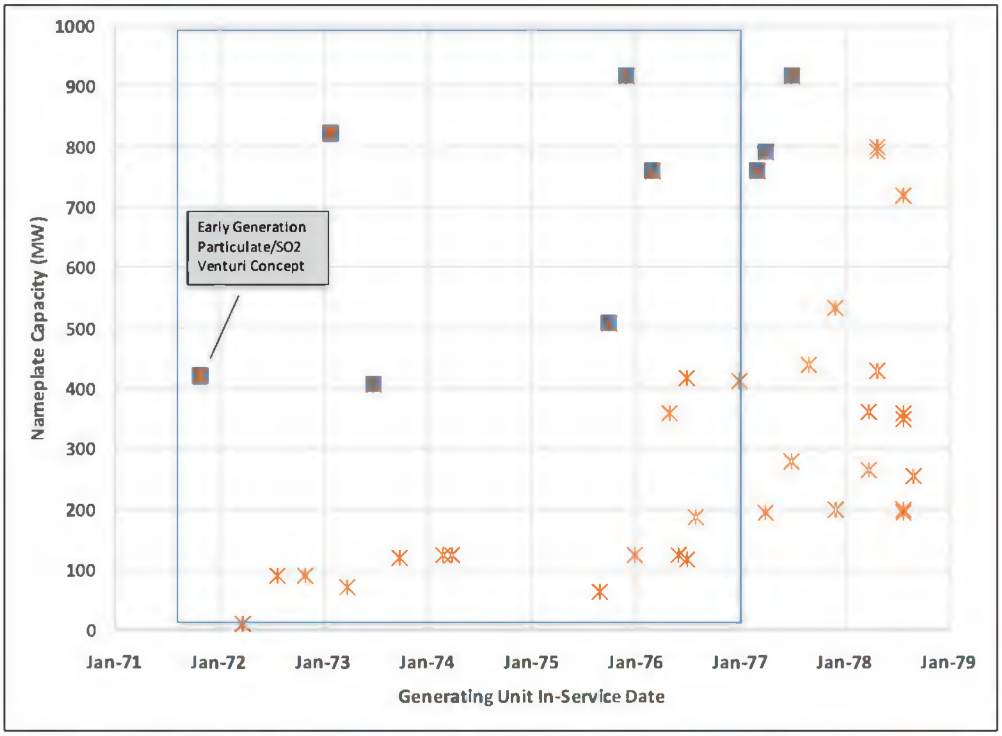

Figure 4-1. Evolution of Wet FGD Technology: The First Decade

In summary, compared to the status of FGD technology at the time of federal legislation mandating use, CCUS at present is characterized by inadequate experience, affecting cost and reliability. Consequently, CCUS experience is inadequate to base federal regulation for CO_2 removal at the scope and timescale as proposed.

4.3 FEED Study Capital Cost

EPA, after lauding FEED studies to justify CCUS as BSER, ignores FEED results when seeking a realistic capital cost for use in their analysis of avoided CO_2 cost ($/tonne). FEED studies provide a better estimate of CCUS capital cost then EPA's use of a hypothetical "model" plant.

As described in Section 3, FEED studies are the second step of a three-phase process to develop engineering details for a CCUS design. Even with six FEED results "in-hand", EPA uses an S&L "model" to generate CCUS capital cost for a "hypothetical" unit, reporting results in Table 7 of the Steam EGU TSD. Of note are three S&L's disclaimers in the source document describing the limits in the use of the model to generate costs.[37] These address scope, site factors, and the lack of a cost "benchmark" – as described as follows:

[37] IPM Model – Updates to Cost and Performance for APC Technologies: CO_2 Reduction Retrofit Cost Development Methodology, Final Report, Project 13527-002, March, 2023. Hereafter S&L 2023 CO_2 IPM.

Scope:

Transportation, storage, and monitoring (TS&M) of the captured CO_2 are not included in the base cost estimates and instead costs can be included as a user input on a $/ton basis.

Site Factors:

The IPM cost equations do not account for site-specific factors that can significantly affect costs, such as flue gas volume and temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions.

Cost "Benchmark" or Validation:

Due to the limited availability of actual as-spent costs for CO_2 capture projects, the cost estimation tool could not be benchmarked against recently executed projects to confirm how accurately it reflects current market conditions.[38]

These disclaimers are clear – scope is not complete and terminates with CO_2 at the fence line; site factors are ignored; and results are not validated with experience. Consequently, cost estimates for CCUS capital and the levelized cost to avoid CO_2 ($/tonne) are at-risk. An alternative approach is to use FEED site specific results and adopt the average capital cost.

4.3.1 Coal-Fired Applications

Figure 4-2 presents CCUS capital cost *per net generating capacity after CCUS* for the two demonstrations and the six FEED studies for coal-fired generating units. Capital cost is reported for Sask Power Boundary Dam 3,[39] Sask Power Shand,[40] Petra Nova,[41] Basin Electric Dry Fork,[42] Minnkota Milton R. Young,[43] Enchant Energy San Juan,[44] Nebraska Public Power

[38] S&L 2023 CO_2 IPM at p. 1.

[39] Coryn, Bruce, *CCS Business Cases*, International CCS Knowledge Center, Aug 16, 2019, Pittsburgh, PA.

[40] Giannaris, S. et. al., Implementing a second-generation CCS facility on a coal fired power station – results of a feasibility study to retrofit SaskPower's Shand power station with CCS, available at: https://ccsknowledge.com/pub/Publications/2020May_Implementing_2ndGenCCS_Feasibility_Study_Results_Retrofit_SaskPower_ShandPowerStation_CCS.pdf.

[41] Final Scientific/Technical Report, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project,* DOE Award Number DE-FE0003311, Petra Nova Parish Holdings LLC, March 31, 2020, Report DOE-PNPH-03311. Hereafter Petra Nova 2020 Final Report.

[42] Commercial-Scale Front-End Engineering Design Study for MTR's Membrane CO_2 Capture Process, Final Technical Report, November 10, 2022. Hereafter 2022 MTR FEED Report.

[43] Project Tundra: Postcombustion Carbon Capture on the Milton R. Young Station in North Dakota, NRECA Update, October 2022.

[44] Crane, C., *Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station,* Overall Feed Package Report for DOE Cooperative Agreement DE-FE0031843, September 30, 2022.

District Gerald Gentleman,[45] and Prairie State.[46] Figure 4-2 also reports capital cost for one of the hypothetical unit evaluated by NETL: 640 MW (net) with a 10,000 Btu/kwh gross heat rate.[47]

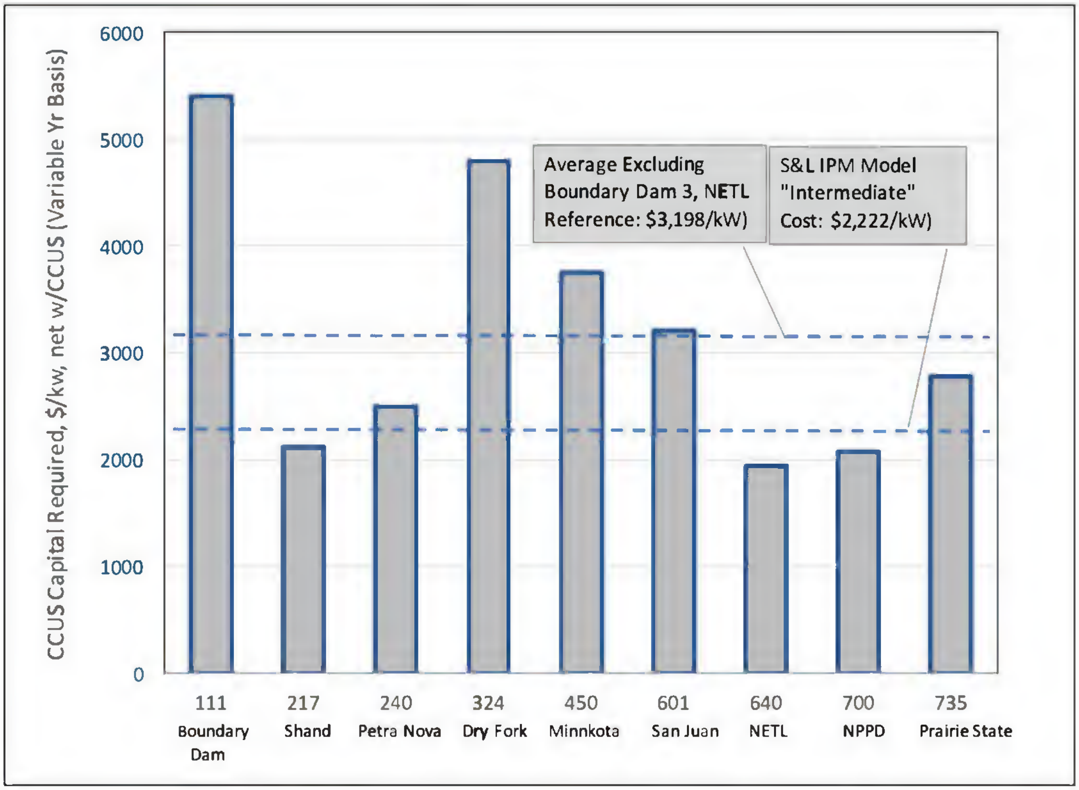

Figure 4-2. CCUS Capital Cost as Reported for Coal-Fired Demonstrations, FEED Studies

Figure 4-2 displays the capital cost from one of EPA's "reference" units (Table 4 of the Steam EGU TSD) used to calculate levelized cost to avoid CO_2 ($/tonne). This calculation, using the S&L IPM model, is conducted for a 400 MW plant with a 10,000 Btu/kWh heat rate, approximating the average conditions of generating capacity and heat rate of units in Figure 4-2. The CCUS capital cost of $2,222/kW $_{\text{(net, with CCUS)}}$ for this reference unit is superimposed on the figure as a reference point for Figure 4-2 results.

[45] Carbon Capture Design and Costing: Phase 2 (C3DC2), Final Project Report, Final Scientific/Technical Report, DOE-FE0031840, March 2023.
[46] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816-MWe Capture Plant Using Mitsubishi Heavy Industries America Post-Combustion CO_2 Capture Technology, August 2, 2022. Hereafter 2022 Prairie State FEED Report.
[47] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL Report 2023-4320, October 14, 2022. Hereafter 2022 Bituminous/NGCC CCUS Retrofit.

Data in Figure 4-2 vary widely by site. Capital cost *per net generating capacity after CCUS* determined by the FEED studies for all but two units exceeds the \$2,222/kW $_{\text{(net, with CCUS)}}$ derived using the S&L IPM procedure for the reference 400 MW unit. The average capital cost from these FEED studies and demonstration tests – excluding the highest and lowest values – provides a more authentic estimate of CCUS capital cost.

Excluding both the highest (Boundary Dam) and lowest (NPPD) costs reported in Figure 4-2, the average capital cost of units in Figure 4-2 is \$3,198/kW $_{\text{(net, with CCUS);}}$ a 44% increase to S&L's reference unit. These FEED study results, even though not "benchmarked" to actual data, are transparent and can be reviewed – unlike costs generated by the S&L IPM model, which include "proprietary data".[48]

It is important to recognize capital cost data in Figure 4-2 reflects only CO_2 capture, compression, and preparation for transport from the fence line – but not for transport to the sequestration or EOR site, injection, and plume monitoring.

Sites requiring minimal pipeline length still incur significant costs for the sequestration step. Two example sites for which information is available are the Minnkota Power and Petra Nova projects.

Minnkota Power's Milton R. Young Station. This site requires only 0.5 mile of pipeline for CO_2 transport to the sequestration site. However, additional facilities are required for substations for CO_2 metering and pumps, monitoring for seismic activity, and plume migration. The injection of CO_2 requires four wells drilled – three for injection and one for subsurface monitoring – to as deep as 10,000 feet. Environmental monitoring instrumentation as required for Underground Injection Control (UIC) Class VI wells is included to assure successful sequestration, as well as financial assurance in accordance with the regulatory requirements of UIC Class VI wells. These ancillary support facilities and provisions are estimated to require an additional \$100M – or, \$289/kW $_{\text{(net, after CCUS)}}$.

Petra Nova. Section 3.3.2 reports of the \$1B for all activities, \$600 M was devoted to CO_2 capture at the plant site with the remaining \$400 million dedicated to, among other needs, the CO_2 transport and upgrade of the West Ranch site. This includes the cost for the 81-mile CO_2 pipeline and for upgrading the oilfield wells to accept more CO_2 for EOR. As a transparent accounting of projects costs has not been released, it is not known how much of the \$400 M is dedicated to these activities.

[48] S&L 2023 CO_2 IPM, page 3. "Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor."

4.3.2 NGCC Applications

Figure 4-3 presents capital cost estimated by FEED studies of NGCC assets that have been reported in the public domain. These FEED studies address the Panda Sherman,[49] Golden Spread Mustang,[50] Daniel 4,[51] and Elk Hills[52] generating units.

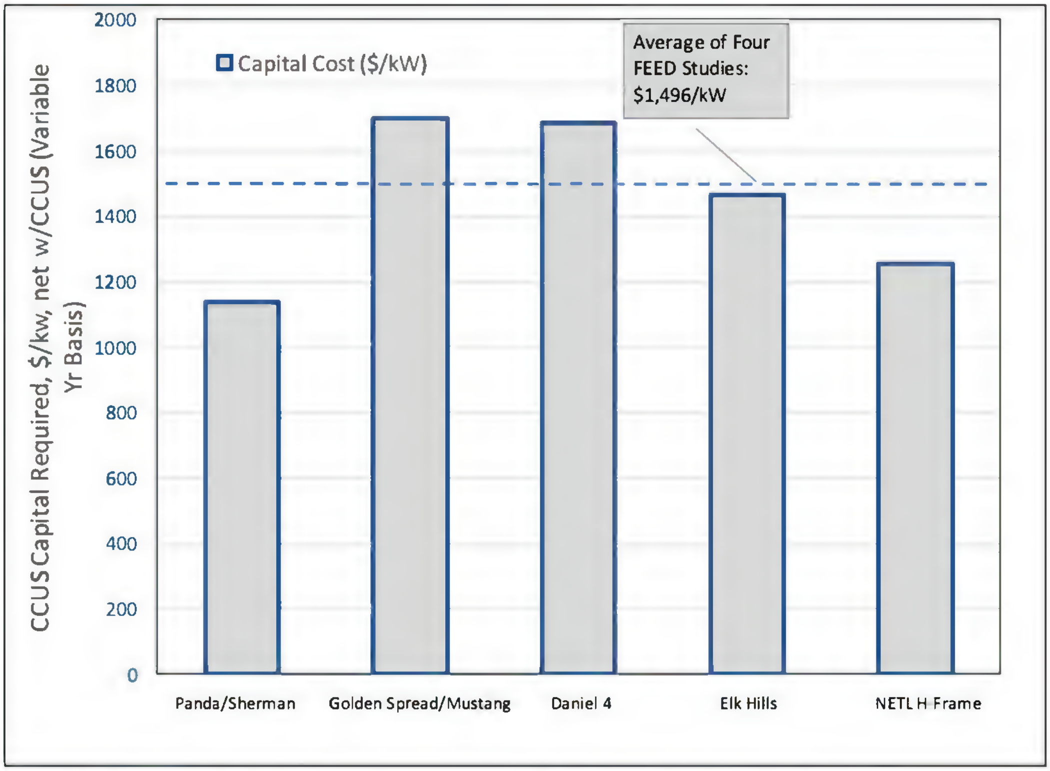

Figure 4-3. CCUS Capital Cost as Reported for NGCC FEED Studies

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[49] Panda Sherman 2022 Final Report.

[50] Rochelle, G., Piperazine Advanced Stripper (PZAS™) Front End Engineering Design (FEED) Study, DE-FE0031844, 2022 Carbon Management Research Project Review, August 17, 2022.

[51] Lunsford, L., et. al., *Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant,* Final Scientific/Technical Report, per DE FE0031847, September 30, 2022. Hereafter 2022 Daniel FEED Report.

[52] *Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant*, Agreement DE-FE0031842, for US DOE/NETL, January 2022. Hereafter 2022 Elk Hills FEED Report.

Figure 4-3 also includes CCUS capital for retrofit to hypothetical NGCC units, as evaluated by NETL.[53] The NETL study estimates capital cost F-Frame and H-Frame gas turbine designations. The H-Frame result is shown in Figure 4-3 for CCUS capital cost, reported as $/kW $_{\text{(net, with CCUS)}}$.

Capital costs reported in Figure 4-3 vary widely by site, driven by, among other factors, the steam source for CCUS. For example, CCUS capital cost projected for Panda Sherman ($1,135/$/kW $_{\text{(net, with CCUS)}}$ is the lowest as the existing HRSG provides steam CCUS duty – but at the cost of a capacity penalty. Conversely, the highest capital cost (~$1,700/$/kW $_{\text{(net, with CCUS)}}$) is estimated for two units (Mustang, Daniel 4) as project scope includes auxiliary boilers to provide steam, preserving generating capacity.

The average of the four FEED studies – albeit representing different concepts to provide CCUS steam –is $1,496/$/kW $_{\text{(net, with CCUS)}}$. This value represents a 20% premium to the cost developed by NETL.

4.4 Inadequate Basis for Levelized $/Tonne Calculation

EPA employs different methodologies to calculate the levelized cost to avoid CO_2 ($/tonne), including the impact of the IRA, for coal-fired and NGCC generating units. For coal, EPA's calculations are recorded in the docket[54] but NGCC calculations are inadequately explained or referenced.

EPA's calculation methodology is reviewed in this section to document shortcomings. However, as stated previously, CCUS is not BSER and cost are not confidently defined; thus, EPA's calculations are speculative and do not reflect present state-of-art in the proposed rulemaking docket.

4.4.1 Coal-fired Application

EPA calculations presented in Table 8 of the Steam EGU TSD, which defined levelized cost per (short) ton including the benefits of the IRA, are invalid for numerous reasons. First, as noted in Section 4.3.1., the capital cost used by EPA for this calculation is derived from the S&L IPM model, for "hypothetical" sites. As noted in Section 4.3.1, this source does not provide capital cost "referenced" to a specific site, nor based on fully transparent data. The example 400 MW unit with a 10,000 Btu/kWh heat rate is assigned a cost of $2,222/$/kW $_{\text{(net, with CCUS)}}$ 31% less than capital from FEED studies ($3,198/$/kW $_{\text{(net, with CCUS)}}$).

Second, calculations are based on the optimistic premise that the CCUS process will operate at 100% availability, thus always be available to accrue tax benefits and defray operating cost. As the bulk of CCUS costs are capital, incurred whether the unit is operating or not, periods of

[53] *Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 3*, DOE/NETL-2023/3848, May 31, 2023. Hereafter 2023 NGCC CCUS Retrofit.

[54] EPA-HQ-OAR-2023_0072-0061_attachment_3.

restricted duty will limit CO_2 delivered and tax benefits. A compromise in availability directly affects the calculated cost to avoid CO_2.

Table 4-1 compares the levelized cost per tonne ($/tonne) for EPA's optimistic case, and two sensitivity cases that explore the role of CCUS capital cost and process availability.[55] Table 4-1 presents EPA's results as calculated using Tables 8 and 9 Steam EGU assumptions, the "intermediate" capital cost ($2,222/kW $_{\text{(net, with CCUS)}}$, and perfect availability (100%). The costs are presented for 50% and 70% capacity factor, and include the benefit of the IRA.[56] Also shown are results to sensitivity analysis.

Table 4-1. Sensitivity Results: Role of Capital Cost, CCUS Reliability of Projected CO2 $/tonne

Capacity Factor (%)	EPA Assumption			FEED Study Average		
	Capital Cost ($/kW)	CCS Reliability	$/Tonne	Capital Cost ($/kW)	CCS Reliability	$/Tonne
50	2,222	100%	15	3,198	100	49
50	2,222	90	23	3,198	90	53
70	2,222	100	-9	3,198	100	15
70	2,222	90	-2	3,198	90	23

The sensitivity of the levelized cost (including IRA benefits) to avoided CO_2 ($/tonne) to changes in CCUS capital and reliability are described as follows:

<u>EPA Capital, Compromised CCUS Availability.</u> This case retains EPA's optimistic capital cost of $2,222/kW $_{\text{(net, with CCUS)}}$, but recognizes that – as witnessed at Sask Power and Petra Nova - CCS availability is typically less than 100%. Results for the two capacity factors are as follows:

- Perfect (100%) Availability. Estimated $/tonne cost is reported as $15 at 50% and -$9 at 70% capacity factor.
- Compromised (90%) Availability. Estimated $/tonne costs elevates to $23 at 50% and - $2 at 70% capacity factor.

<u>FEED Study Capital, Compromised CCUS Availability</u>. Applying the average of FEED study capital of $3,198/kW $_{\text{(net, with CCUS)}}$ for 100% and 90% CCUS reliability derives the following:

- Perfect (100%) Availability. Estimated $/tonne costs elevates to $49 for at 50% and $15 at 70% capacity factor.

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[55] It should be noted the author could not corroborate why Table 8 of the Steam EGU TSD specifies the variable O&M cost used in the calculation is $5/MWh, compared to $23/MWh reported by the S&L IPM source document for what appears to be comparable conditions. For the purpose of this report, calculations adopt EPA's $5/MWh to assure a valid comparison. However, the difference is noted and should be further explored.

[56] The "negative" costs presented in Table 4-1 for two cases reflect EPA's projection that CO_2 removal and sequestration will comprise a profitable venture.

- Compromised (90%) Availability. Estimated \$/tonne costs elevates to \$53 for at 50% and \$23 at 70% capacity factor.

It should be noted that –without the IRA subsidy – the cost to avoid CO_2 per tonne for some cases is a factor of 10 higher compared to 100% CCUS reliability. For capital cost of \$3,198/kW $_{\text{(net, with CCUS)}}$, the levelized cost to avoid CO_2 at 50% capacity factor is \$127 and at 70% capacity factor is \$93.

4.4.2 NGCC Application

As noted for coal-fired duty, CCUS for NGCC duty is not BSER. Both S&L and Bechtel have opined there is negligible experience with CCUS on NGCC conditions. EPA project CCUS capital cost for NGCC using an unconventional metric that biases costs low and extrapolate costs to a wide range of applications using both NGCC and coal-derived basis. These results are flawed, as described as follows.

<u>Capital Cost</u>. EPA projects CCUS capital cost using an incorrect metric. Table 7 of the Combustion Turbine TSD reports capital, fixed O&M, and variable O&M costs for hypothetical NGCC units employing the F-Frame and H-Frame technologies, as derived by NETL for "greenfield" application. Table 7 presents capital cost per net generating capacity (a) replicated from the NETL study[57] and (b) inferred by EPA.

The implied capital for CCUS depends on whether NETL's "conventional" method is chosen, or EPA's inexplicable variant. NETL's conventional method – taking the difference in capital cost with and without CCUS – implies a capital cost of \$1,199/kW $_{\text{(net, with CCUS)}}$ for F-Frame and of \$1,055/kW $_{\text{(net, with CCUS)}}$ for the H-Frame applications

EPA inexplicably changes the capital cost metric. The capital cost EPA attributes to CCUS in Table 7 –\$949/kW for the F-Frame and \$823/kW for the H-Frame – is lower than inferred from NETL's methodology, as EPA normalizes the inferred CCUS cost by net generating capacity prior to CCUS retrofit.[58] This approach is flawed as it does not account for 33 MW of net power consumed due to the CCUS process.

<u>Extrapolation to Different Applications</u>. EPA's Combustion Turbine GHG TSD employs a series of extrapolations to infer CCUS capital, fixed operating, and variable operating cost for a variety of combustion turbine applications.

EPA (a) misuses the power law relationships describing the change in equipment cost with generating capacity, and (b) fails to recognize the difference in CCUS process conditions

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[57] 2022 Bituminous/NGCC CCUS Retrofit. Exhibit 9-5 at 710.

[58] Personal Communication, Lisa Thompson to Liz Williamson, July 25, 2023. *The \$949/kW cost in Table 7 is calculated by dividing the absolute difference in the costs of the combined cycle EGU with CCS and without CCS divided by the net output of the combined cycle EGU without CCS. In this case, 688 million divided by 727,000 kW (rounded).*

between coal-fired vs NGCC duty. As a consequence, EPA projects CCUS cost for NGCC duty (3-4% CO_2) based on coal-fired duty (with 12% CO_2). Notably, a 2013 NETL report[59] cautions extrapolations such as these, which EPA follows to produce Figures 1-5 in the Combustion Turbine TSD.

In perspective, these EPA cost results are not of consequence as CCUS is not a demonstrated technology on NGCC (or coal-fired application), and a basis for cost extrapolations does not exist. The shortcomings in EPA's methodology are further discussed in Appendix A for reference.

In Summary:

- EPA estimates of CCUS capital cost for coal applications in Tables 6 and 7 of the Steam EGU TSD are low. The real-world source is the average capital cost derived from the two industrial demonstrations and FEED studies, eliminating the high (Boundary Dam 3) and lowest (NETL) cost units. These real-world projects define a cost of $3,198, a 43% premium to that generated by the IPM model. Revised estimates of $/tonne incurred – using FEED-study capital cost and accounting for a 10% compromise in CCS reliability - increases cost calculated for 50% capacity factor from $23 to $53/tonne with the IRA credit, and for 70% capacity factor from $2 to $23/tonne *if CCUS works as planned for at least 12 years*.

- EPA estimates of CCUS capital cost for NGCC application presented in the Combustion Turbine GHG Mitigation TSD are not transparent. EPA infers CCUS capital from a NGCC CCUS retrofit study issued May 28, 2023, in lieu of the more real-world approach of averaging cost from the four FEED studies. This latter approach derives capital cost exceeding that of the NETL-derived hypothetical site by 20%. Most notably, there are no applications of CCUS on NGCC units – thus no sources to verify the design from which cost is derived. Two EPA contractors agree. Specifically, both (a) S&L in reporting the projected CCUS schedule and IPM model and (b) Bechtel in the FEED study for Panda/Sherman both state limited experience with CCUS on NGCC brings uncertainties, which compromise the authenticity of any cost estimate.

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[59] *Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology*, DOE/NETL-341/013113, January 2013. Hereafter 2013 Scaling Quality Guidelines.

5 CO2 Pipeline Permitting Issues

Broad CCUS deployment will require a significant increase in CO_2 pipeline capacity. Securing new pipelines requires design, permitting, and construction tasks – all within a time frame that will not delay the entire project. Section 5 presents examples of ongoing permitting conflicts, demonstrating how delays can be incurred. The takeaway from this discussion is used in the critique of the CCUS implementation schedule presented in Section 6.

5.1 Background

Deploying CCUS to numerous generating units – such as the 39 units EPA estimates to deploy per the 2023 Integrated Baseline Analysis - requires expanding CO_2 pipelines capability. One limiting step to CCUS deployment is acquiring the necessary right-of-way for pipelines to transport the CO_2. EPA in their projected CCUS schedule estimate 130 weeks to be required for permitting a pipeline. The Global CCS Institute assumes that in acquiring pipeline access during their proposed almost 9-year schedule "…. there is no significant community opposition." [60]

A key factor determinate in the schedule is the pipeline length to access either EOR or terrestrial sequestration. Each additional mile of pipeline requires additional owners' land to access and acquire right-of-way. Pipeline permitting issues are addressed following a brief discussion of pipeline length.

5.1.1 Pipeline Length

The length of the pipeline to transport CO_2 from candidate CCUS sites can vary by an order of magnitude. This range is evidenced by several units that have completed CCUS FEED studies. The CO_2 pipeline length for projects located adjacent to the generating site – such as for Project Tundra at the coal-fired Dry Fork station, and the Elk Hills NGCC application – are less than a few miles. Conversely, and as shown in Figure 5-1, the pipeline length necessary to transport CO_2 to the ECO2S Regional Storage Complex from Mississippi Power's Daniel Unit 4 is 180 miles and from Plant Miller 150 miles.[61] Although it appears desirable to rely on CCUS installations on units located at or adjacent to a disposition site, such a strategy is unrealistic as host units may not have favorable characteristics (generating capacity, capacity factor, remaining lifetime).

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[60] CCS Institute report 20-22; p. 48.

[61] Riestenberg, D. et. al., Establishing an Early Carbon Dioxide Storage Complex in Kemper County, MI: Project EICO2S, 2020 DOE/NETL Integrated Review Webinar, August 17-19, 2020. Hereafter 2020 Kemper County Storage Complex.

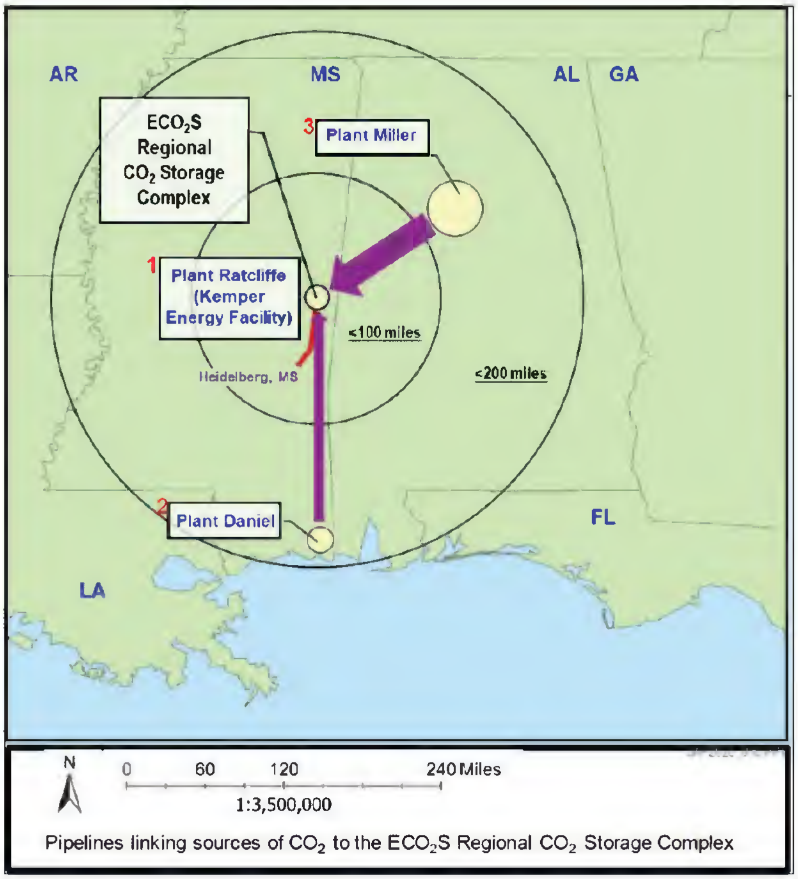

Figure 5-1. Candidate CO_2 Pipeline Routing, Length: Plants Daniel and Miller

Both the DOE and EPA adopt a typical pipeline length to be 100 km – 62 miles – for which there is no technical basis; EPA concedes this assumption as a means for "standardization".[62] The DOE applies this "default" 100 km pipeline length in their cost evaluation for "hypothetical" plant. EPA states ".... there are 43 States containing areas within 100 km from currently assessed onshore or offshore storage resources in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs";[63] this observation is inadequate to justify the 100-km length as a default.

Pipeline length will be driven by finding adequate storage volume to accept the CO_2 quantity from a large generating unit; it is unlikely the required storage will be located at the nearest boundary of any terrestrial basin. The NETL Atlas[64] - developed to provide "high-level" assessment and not a detailed assay of disposition sites - reveals significant heterogeneity of features that affect CO_2 injection rate and storage. The quantity of CO_2 to be stored for a coal-

[62] 88 Fed. Reg at 33,297, n 333.
[63] Ibid; 33,298.
[64] NETL Carbon Storage Atlas; Fifth Edition, DOE Office of Fossil Energy, August 2015. Hereafter 2015 DOE/NETL Storage Atlas.

fired or NGCC unit of generating capacity large enough for CCUS to be feasible (i.e., 400 MW or more) is far greater than demonstrated at all but a few sequestration sites permitted to date. The Global CCS Institute reports 22 projects either in operation or construction for 2024 or 2025 duty with only two sequestering 5 or more million tonnes of CO_2 per year (Mt/a).[65]

In summary, EPA's assumption of a 100-km average pipeline length to access an acceptable reservoir for power generation units is not substantiated.

Section 7 presents a graphic depicting arrangement of the 39 units projected by EPA to adopt CCUS, showing the "footprint" required for pipelines of 100 and 200 km.

5.1.2 Pipeline Projects: Select Description

The Midwest is the nexus for CO_2 pipeline permitting. Several entities are well into the process of developing pipelines to acquire CO_2 from ethanol facilities. The major actors are Summit/Midwest Carbon Solutions, Navigator, and Wolf Carbon. Key features of each project are summarized as follows:

- Navigator[66] proposes 900-mile pipeline bisecting Iowa from northwest to southeast and transporting CO_2 to Illinois. (~$3.2B). A total of 1,300 miles via South Dakota, Nebraska, Minnesota, in addition to Iowa, is proposed. The permit application was filed in July 2022.

- Wolf Carbon[67] propose 280 miles of pipeline to transport CO_2 from ADM ethanol producing facilities in eastern Iowa to Decatur, IL for terrestrial sequestration.

- Summit Carbon[68] will build 700 miles of pipeline in western and northern Iowa to transport CO_2 to North Dakota, for existing EOR application. In Iowa alone, the proposed pipeline will cross 30 counties.[69]

These entities are pursuing pipeline permits in several states: Iowa, Minnesota, North Dakota, Nebraska, and South Dakota. The permitting requirements vary significantly by state– Iowa presents perhaps the most structured "steps", and Nebraska the least. The lack of structured steps currently in Nebraska does not imply permitting requirements are less strict than Iowa; but that Nebraska's process for permitting CO_2 pipelines is evolving.

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[65] *Global Status of CCS 2022*, issued by the Global CCS Institute. Section 6.2. Available at https://www.globalccsinstitute.com/resources/global-status-of-ccs-2022/.
[66] https://heartlandgreenway.com/about-us/.
[67] https://wolfcarbonsolutions.com/mt-simon-hub/.
[68] https://summitcarbonsolutions.com/project-footprint/.
[69] *Proposed Iowa Pipeline Would Cross 30 Counties*, Radio Iowa, Aug 20, 2021. https://www.radioiowa.com/2021/08/30/proposed-carbon-dioxide-pipeline-would-cross-30-iowa-counties/.

Landowners cite several reasons for resisting access to their property. One frequent reason cited is concern that agricultural productivity is compromised within the pipeline easements – meaning productivity is reduced 15% for corn and 25% for soy.[70]

5.2 Permitting Experience

Both the EPA's and the Global CCS Institute's treatment of pipeline permitting is unrealistic. This section will report opposition encountered by "grass-roots" entities, with support from organizations such as the Eco-Justice Collaborative and the Sierra Club. These organizations, among others, promote campaigns to resist pipeline permits; in Illinois providing an on-line petition.[71]

Each state presents different barriers – and opportunities – to pipeline permitting and construction. Within each state, perhaps the most contentious issue is eminent domain – which a project developer can invoke if they argue the proposed pipeline is of "public use or public convenience and necessity." Success in this argument enables acquisition accompanied by fair compensation.

5.2.1 Iowa

CO_2 pipelines could be of paramount importance in Iowa, as ethanol production asserts significant financial impact on the state and is the major CO_2 source. A total of 57% of corn farmed in Iowa is processed for ethanol. Iowa is noteworthy in that pipeline permitting, design, and construction decisions are controlled by a governing body – the Iowa Utilities Board (IUB).[72] The permitting process consists of (a) sponsoring public information meetings in each county, (b) allowing developers 30 days after the public meetings to file a petition for a permit, and (c) establishing a schedule for public hearings, including pre-hearing filing dates for testimonies and exhibits. Upon completing these events, IUB can render a decision.

All three developers propose pipelines in Iowa – 830 miles by Navigator; 95 miles (eastern Iowa) by Wolf Carbon, and 2,000 miles (northern and western Iowa) by Summit. A total of 48% of pipeline length proposed by the Navigator and Summit project are in Iowa.

The numerous barriers to the pipeline pre-feasibility work and permitting in Iowa are summarized as follows:

Survey Access. Iowa law – as presently enacted - allows pipeline companies access to proposed easements for survey, with the requirement that informational meetings are sponsored, and

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[70] Pipeline study shows soil compaction and crop yield impacts in construction right-of-way, Iowa state university College of Agricultural and Life sciences, November 11, 2021. Available at https://www.cals.iastate.edu/news/releases/pipeline-study-shows-soil-compaction-and-crop-yield-impacts-construction-right-way.

[71] https://noillinoisco2pipelines.org/.

[72] https://www.agriculture.com/news/business/landowner-battles-against-pipelines-vary-by-state.

landowners notified. The constitutionality of this law is being challenged by four property owners that refuse access the property.[73]

Denial of Right-of-Way. A total of 430 landowners are rejecting offers to sell right-of-way to CO_2 pipeline owners.

Eminent Domain. Pipeline developers can use eminent domain – at the discretion of the IUB – to build pipelines on the property of owners who refuse to voluntarily comply. Eminent domain decisions are made on an individual case-by-case basis. Resistance to eminent domain is strong - 78% of Iowans oppose it's use.[74]

A legal challenge to eminent domain is being considered in Iowa, as follow-on to earlier challenges introduced in 2015.[75] Iowa proposed a bill requiring pipeline developers to acquire right-of-way voluntarily from 90% of landowners prior to invoking eminent domain.[76] An additional challenge to eminent domain is based on rejecting the "public use" argument, despite the claimed CO_2 pipeline benefit of supporting ethanol production.

Approximately 30% of Summit's proposed pipeline route crosses 1,000 parcels of land – for which they have obtained 40% of the required voluntary easements[77] for the 680-mile segment in Iowa. The prospect for eminent domain is of great concern; media cite eminent domain "…." has the potential to elongate the final permit hearing, when eminent domain requests are individually considered.

Finally, some owners are adamant they will not participate:[78]

"When is 'no' accepted as 'no'? How many times do we have to say no? My answer in 2021 for an easement was 'no.' My answer today is 'no.' My answer tomorrow and any days forward will be a resounding 'no.' Our land is not for sale."

5.2.2 Nebraska

Nebraska is reported – at present –to not have established CO_2 permitting requirements; the lack of such requirements is not to be interpreted that Nebraska is – or will be – lenient. For example, in contrast to Iowa where pipeline developers can access sites (under preconditions) for survey, Nebraska has no such rule. Further, proposed legislation in Nebraska will require owners to remove CO_2 pipelines, once the project and CO_2 removal duty is complete. Finally, unlike other states, there is no option of eminent domain.

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[73] https://www.agriculture.com/news/business/judge-says-pipeline-survey-lawsuit-should-go-to-trial.
[74] https://www.agriculture.com/news/business/wolf-carbon-pipeline-plans-might-be-delayed.
[75] https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end.
[76] https://www.agriculture.com/news/business/house-passes-bill-to-restrict-eminent-domain-for-pipeline
[77] https://www.agriculture.com/carbon-pipeline-opponents-decry-sham-process.
[78] https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end.

5.2.3 Illinois

Illinois presently hosts numerous studies of geologic sequestration to support the state's concentration of ethanol production sites. At present, there is a sole – and short – pipeline confined to the ADM ethanol facility in Decatur, routing CO_2 captured for on-site sequestration. However, some observers project Illinois could be a superhighway for CO_2 pipelines.[79] The responsibility for permitting pipelines is within the Illinois Commerce Commission (ICC).

Local resistance exists. McDonough County issued a two-year moratorium on pipeline approval and permitting actions, primarily to allow for improved federal safety design standards. Separately, a representative of the ICC noted that 14 separate permits for federal, state, and local permits are required for a pipeline, of which none had been acquired as of September 2022.[80]

5.3 Timeline Summary

The currently available timelines for the Summit and Navigator project are summarized as follows:

Navigator. This developer initiated public hearing in 4Q 2021, and as of early 2022 planned to start construction in 2024.

Wolf Carbon. Wolf files a pipeline permit in February of 2023 with the IUB and it is uncertain if construction could start in the second quarter of 2024.[81] Wolf reports the permit applications does not – at least to date – include a request to use eminent domain.

Summit. Summit filed an initial permit in August 2021 and – upon encountering delays - asked for a decision by the end-of-year of 2024. This timeline represents almost a 3.5-year duration.[82] The Sierra Club – who oppose the pipeline along with select landowners – propose the hearing be delayed to 2024. Summit is reported as of late May 2022 to have signed easements with approximately 30% of the landowners required to complete the pipeline within Iowa.[83]

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[79] Advocates urge Illinois landowners to prepare for risks from CO2 pipelines, March 15, 2022, Energy New Network. Available at https://energynews.us/2022/03/15/advocates-urge-illinois-landowners-to-prepare-for-risks-from-co2-pipelines/.

[80] Illinois County Offered Payments to Back Navigator Carbon Dioxide Pipeline, February 3, 2023, Energy New Network. Available at https://energynews.us/2023/02/03/illinois-county-offered-payments-to-back-navigator-carbon-dioxide-pipeline/.

[81] https://www.agriculture.com/news/business/wolf-carbon-pipeline-plans-might-be-delayed.

[82] https://www.agriculture.com/news/business/pipeline-company-wants-permit-decision-in-iowa-by-year-s-end.

[83] *Strange Bedfellows: Farmers and Big Green Square Off Against Biden and the GOP*, Politico, May 29, 2022. https://www.politico.com/news/2022/05/29/iowa-manchin-carbon-capture-pipeline-00030361.

One observer thinks at least 3 years will be required to resolve permit issues; dozens of lawsuits have been filed in Iowa, and North and South Dakota – most initiated by pipeline companies to secure access.[84]

Takeaway: The most evolved reference case for CO_2 pipeline permitting – activities for Summit within Iowa – at present project a 3.5-year timeframe from proposal to final hearing. Abiding by this schedule assumes the final hearing is conducted at end-of-year 2024. This projected timeframe exceeds all schedules project by EPA.

[84] https://www.agriculture.com/news/business/landowner-battles-against-pipelines-vary-by-state.

6 CRITIQUE OF CCUS SCHEDULE

The EPA has proposed a five-year schedule to execute a CCUS project from concept through delivery of CO_2 for sequestration or EOR. Section 6 critiques EPA's proposal and demonstrates a 5-year duration is inadequate.

Eight demonstration projects or FEED studies represented in Figure 4-2, four delivered at least partial schedules. In addition, two FEED studies of CCUS to NGCC units illustrated in Figure 4-3 delivered partial schedules.

None of the proposed schedules support a five-year timeline for the complete scope to deploy CCUS, or seriously address permitting for sequestration or CO_2 pipelines, much less consider the timelines necessary to finance a CCUS project.

6.1 S&L Proposed Schedule

The EPA sponsored S&L to develop a CCUS schedule, from concept to delivering commercial quantities of CO_2 for disposition. Figure 6-1 presents the image of the schedule in the docket[85] describing a "baseline" duration of 6.25 years and an "extended" duration of seven years.

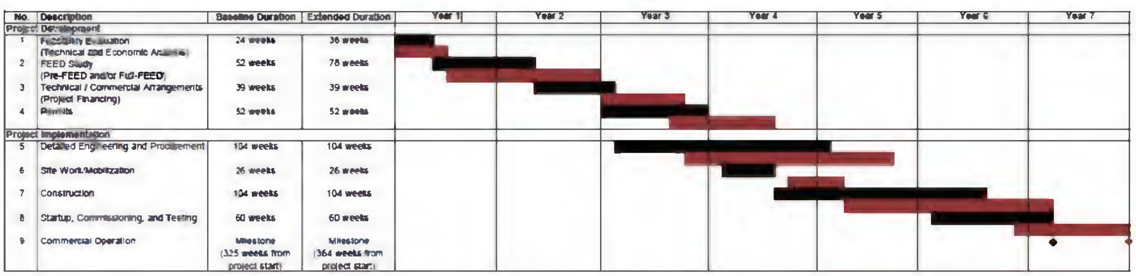

Figure 6-1. S&L CCS Deployment Schedule

S&L describes the scope of duties addressed in the schedule to include project development (feasibility assessment, FEED studies, developing commercial agreement and technical specifications, permitting, award of contracts) and implementation (detailed engineering, fabrication, construction, startup, commissioning, and testing).

S&L in their supporting material describe two barriers to this schedule, which EPA ignores in the Steam EGU TSD. These barriers are:

Potential Impacts, Road Blocks. S&L list seven potential "schedule impacts" than can impose a delay: equipment fabrication or delivery; weather, underground interferences; challenging site for retrofit; contract negotiations and financing; and – perhaps the largest – public comment

[85] S&L_CCS_Schedule_EPA-HQ-OAR-2023-0072-0061_attachment_16.pdf.

periods. Example "roadblocks" or "bottlenecks" are a limited number of vendors and constructors for work of this scale; infrastructure of steel availability and heavy construction equipment; engineering due to large project volumes.

Incomplete Scope. S&L present a disclaimer stating the schedule addresses on-site activities, excluding those external to the site but critical for project execution.

This schedule is for the on-site CCS system only and does not include the scope associated with the development of the CO2 off-take / storage (including transportation, sequestration, enhanced oil recovery utilization, and/or utilization).

In summary, the S&L schedule does not reflect all activities required for a complete CCS project, and thus does not represent a realistic timeline.

6.2 Global CCS Institute Schedule

A CCUS schedule proposed by the Global CCS Institute - an organization funded by government entities, and suppliers of process equipment and engineering services - projects an almost 9-year timeline.[86] Figure 6-2 presents this schedule as extracted from the referenced Global Status of CCUS 2022 report.

The Global CCS Institute offers the following context – actually disclaimers – regarding their schedule:

- a large complex CCUS project may take a decade to progress from concept to operation;
- the necessary tenements and approvals for geological storage of CO_2 from regulators, generally requires years to complete; and
- The identification and appraisal of geological resources for the storage of CO_2 is a costly and time-consuming process. These activities typically take a few years to complete and are subject to the availability of geoscientists with appropriate experience and the critical equipment required to collect data and drill wells.[87]

The Global CCS Institute report does identify conditions where a shorter timeline is feasible; and such sites may exist. It is noteworthy EPA's assumption of five years for broad deployment is almost half of that projected by an organization whose objective is to promote CCUS.

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[86] *Global Status of CCS 2022*, issued by the Global CCS Institute. P. 47. Available at https://www.globalccsinstitute.com/resources/global-status-of-ccs-2022/.

[87] Ibid. at pgs. 47-48.

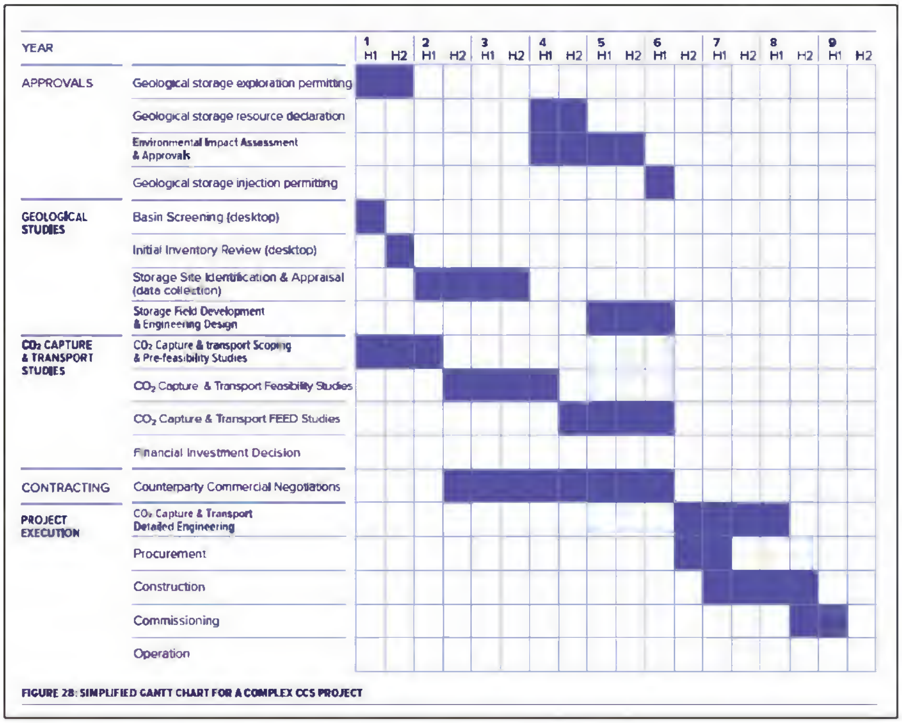

Figure 6-2. Global CCS Institute Deployment Schedule

6.3 EPA's Compressed Schedule

The schedule EPA presents in the Steam EGU TSD is a compressed version of the schedule developed by S&L. S&L does not consider the transport and disposition of CO_2 off-site within their timeline scope; EPA proposes a schedule for this task. EPA advises between one to two years are required for a sequestration site feasibility study, characterization, and permitting.[88] EPA cite as evidence source material that is not convincing or supportive: (a) site characterization and permitting for a 10 MW pilot plant – generating a small fraction of the CO_2 produced by a commercial plant, and that will operate for five years;[89] a management overview of the four phases of the CarbonSafe program (that total more than 5 years).[90] EPA's third example is experience of a project in North Dakota, a state with primacy, in securing a sequestration permit, but absent documentation of a final schedule certifying permits-in-hand (although cautioning "Pore space acquisition takes more time than you think".)[91] These citations do not support EPA's 104 week duration for site characterization and permitting that is included

[88] Steam EGU TSD. at 36.

[89] Large Pilot Testing of Linde-BASF Advanced Post-Combustion Carbon Dioxide Capture Technology at a Coal-Fired Power Plant. Available at https://www.netl.doe.gov/projects/project-information.aspx?k=FE0031581

[90] CarbonSafe Storage Assurance Facility Enterprise: Available at: https://netl.doe.gov/sites/default/files/2022-05/IG-CarbonSAFE_20220512.pdf

[91] Peck, W., North Dakota CarbonSafe Phase III: Site Characterization and Permitting, August 2, 2021, available at https://netl.doe.gov/sites/default/files/netl-file/21CMOG_CCUS_Peck.pdf

in their five-year schedule. Similarly, no evidence is offered to support their 130-week estimate for pipeline design, feasibility, permitting.

EPA – quite arbitrarily – elects to compress the schedule proposed by S&L. Specifically, EPA states:

> *"EPA believes that a five-year project timeline for deploying CCS, and related infrastructure and equipment, is reasonable. There are opportunities to compress schedules, expedite certain portions of the project schedule that are amenable to faster timetables, and conduct various components of the schedule concurrently.*
>
> EPA cites no basis for the compression – but describe that "*...sources expedite (where feasible) the scheduled deployment of CCS technology in a reasonable manner in order to meet the timing requirements of this action."* Regarding CO_2 capture design and development actions, EPA opine *"Each of these individual steps need not be in a sequential, and many of these actions can be planned well in advance, such that there can be significant time savings across these project planning steps."*[92]

Finally, EPA ignores risks inherent in emerging technologies, which given uncertainty in hardware design and performance – complicates parallel execution of engineering and procurement. EPA does not consider the risks in procuring components before all design work is complete – which can lead to cost overruns and schedule delay when it becomes necessary to modify the final design, perhaps altering early phases.

The achievable reduction in schedule in most cases is negligible – most schedules (i.e., Elk Hills) already include "parallel" steps such as final design and construction.

6.4 Real World CCUS Project Schedules

There are 13 CCUS projects for which schedules have been developed through at least the CO_2 capture. Few CCUS projects completely address the scope from process conception through CO_2 delivery and site injection (for sequestration or EOR). Two of these activities – Sask Power Boundary Dam 3 and Petra Nova – are discussed in Section 3. No other projects can offer real world experience with a complete project execution, accounting for all uncertainties in design, construction, and permitting.

This subsection reviews available schedule data from projects to compare to the EPA's proposed schedule. Schedules for both NGCC and coal-fired CCUS projects are considered. This high-level summary provides for each project site, as available, the following: the total project duration, the FEED design (including developing procurement specification) duration, and the period for construction. Comments on each project are offered for additional consideration.

[92] Steam EGU TSD at 36.

6.4.1 NGCC Schedule

Table 6-1 overviews schedule information for two NGCC applications- Elk Hills and Mississippi Power Plant Daniel Unit 4 - for which information is publicly available concerning schedule.

Table 6-1. Summary Schedule Information: NGCC CCUS Projects

Project/Site	Actions Addressed	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Elk Hills[93]	-CO_2 Site Prep: N/A -pre-FEED -FEED -Design/Const.	12 mos. (pre-FEED) 29 mos. FEED[94] Design/Spec 24 mos. (p.44)	55 mos.	96 mos. for FEED, other activities. Total ~8 yrs
Plant Daniel	-CO_2 Site prep: ECO_2S (start 2017) -FEED -Design/Const.	20 mos. (FEED: 1/29/20 to 9/30/21[95]	60 mos. including final design[96]	80 mos. w/o permitting for pipeline, sequestration

Elk Hills. This 550 MW (net) unit is regarded by the California Energy Commission as highly advantageous for CCUS, and describe it as "…one of the most suitable locations for the extraction of hydrocarbons and the sequestration of CO_2 in North America."[97] Even with these ideal conditions – the generating unit located directly above the sequestration fields that are already characterized - a minimum of eight years is required. After a presumed 12-month pre-FEED evaluation of CCS feasibility, the Elk Hills final report describes a 29-month FEED study, followed by 55 months for remaining activities. The activities per the project schedule (Appendix A, Figure A-1) following the 29-month FEED study are (a) 10 months of post-FEED events developing requests for proposals (RFPs), regulatory documentation and approval, and bids for select equipment, and (b) detailed engineering and procurement are (parallel activities).

Construction is authorized to start once 60% of detail engineering is complete and requires 24 months. Figure A-1 shows several major tasks are conducted in parallel.

Summary: The Elk Hills CCUS project benefits from near-ideal site conditions, with access to a well-characterized sequestration site. Despite the absence of delays due to pipeline permitting, this project experience demonstrates a project timeline between eight and nine years.

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93 2022 Elk Hills FEED Report. Page 1220.

94 Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant, Graphics Deck per DE-FE00311842, February, 2022. Page 6.

95 Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Plant, Virtual Meeting Graphics deck, Aug 2, 2021. P.21.

96 2022 Daniel FEED Report.

97 Appendix F, URS Report on CO_2 Sequestration for California Energy Commission, 2010.

Mississippi Power Plant Daniel Unit 4. This 525 MW (net) unit was evaluated in FEED study to retrofit the Linde-BASF amine-absorption process. A potential schedule describing activities from concept evaluation to CO_2 delivery – exclusive of permitting – can be considered, recognizing work began in 2017 to characterize the likely CO_2 sequestration site (Kemper County Storage Complex).[98] Consequently, considering the FEED study (20 months) and Final Design/Construction (60 mos) totals almost seven years; but this does not account for the work initiated in 2017 to evaluate sequestration options at the Kemper County Storage Complex. In addition, pipeline issues are not addressed – which as shown by experience in Iowa, could induce delays in the permitting, design, and construction of the 181-mile pipeline segment.

Summary. A realistic timeline for CCUS as represented for Daniel Unit 4 is best described by Southern Company in previous comments addressing CO_2 control options NGCC units.[99] This timeline – including technology evaluation, site permitting, process installation, and ramp-up for sustained operation – projects 10 years as necessary.

6.4.2 Coal-Fired CCUS Applications

Table 6-2 overviews schedule information for coal-fired applications, including Sask Power Boundary Dam 3 and Petra Nova. The implementation schedule for these projects is presented in Section 3.3.

Table 6-2. Summary Schedule Information: Coal-fired CCUS Projects

Project/Site	Actions Addressed in Schedule	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Sask Power	Per Sask Power: Commitment to completion[100]		3 yrs	6 yrs: Concept to completion. Existing EOR site, limited pipeline
Petra Nova[101]	6/10 to 12/16	Not specified	2014-2016[102]	80-mile pipeline to existing pipeline to EOR site.

[98] 2020 Kemper County Storage Complex.

[99] Comments of Southern Company to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, Docket ID No. EPA-HQ-OAR-2022-0723, December 21, 2022.

[100] SaskPower's Boundary Dam Carbon Capture Project Wins Powers Highest Award, Power, https://www.powermag.com/saskpowers-boundary-dam-carbon-capture-project-wins-powers-highest-award/.

[101] WA Parish Post-Combustion CO2 Capture and Sequestration Project, Topical Report: Final Public Design Report, Award No. DE-FE0003311. Pages 7, 8.

[102] https://www.businesswire.com/news/home/20170109006496/en/NRG-Energy-JX-Nippon-Complete-World%E2%80%99s-Largest.

Table 6-2. Summary Schedule Information: Coal-fired CCUS Projects (Cont'd)

Project/Site	Actions Addressed	Pre-FEED FEED Design, Specifications	Post-FEED Design, Construction	Comment
Basin Electric/Dry Fork[103]	Storage feasibility (March 2017)[104] to Oct 2029 CO_2 injection.	FEED. Oct 2019 to June 2022 (32 mos.)[105] Pilot study: 2022-2025	July 2025 – Oct 2029 for 1st CO_2 capture [106]	Detailed design start July 2025 to assure operation by Jan 2032[107]
Minnkota Power/Milton R Young[108]	-Storage feasibility (2015+), pilot plant -pre-FEED -FEED -Final Design/Con.	FEED: 2019 thru 2021 (24 mos.) Detailed Engineering and 6-12 mos. for vendor review, selection	Q1 2024-2028	Total duration: 2015-2028 Permitting duration atypical per state "primacy", adjacent sequestration site.
Prairie State[109]	-Illinois Corridor -FEED -Final Design/Con.	2/3/20 - 11/30/21 (22 months)[110]	EPC: 8/23 thru 4/27 (3.75 yrs)[111]	Sequestration study in Illinois Corridor started in 2007
San Juan[112]	-pre-FEED -FEED	5/22/2020-10/29/2021[113]	2/12/24 thru 6/04/26	21-mile pipeline not addressed
Shand	-pre-FEED -FEED/Final design	-pre-FEED complete -FEED 18 months[114]	Detailed Design/Constr 36 months[115]	

[103] 2022 MTR FEED Report.

[104] Wyoming CarbonSAFE Phase II: Storage Complex Feasibility (Commercial-Scale Carbon Storage Complex Feasibility Study at Dry Fork Station, Wyoming. DE-FE0031624, April 30, 2021.

[105] Commercial-Scale Front End Engineering Design (FEED) Study for MTR's Membrane CO2 Capture Process, Project Closeout Meeting, June 24, 2022. See graphic 3.

[106] Ibid.

[107] DE-FE0031846 page 38.

[108] Project Tundra: Postcombustion Carbon Capture on the Milton R Young Station, NRECA Update, October, 2022.

[109] 2022 Prairie State FEED Report. Page 145.

[110] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816 MWe Capture Plant using Mitsubishi Heavy Industries Post-Combustion CO2 Capture Technology, DOE/NETL Project Closeout Meeting, June 14, 2022. See Graphic 12. Hereafter 2022 Prairie State Close Out.

[111] Ibid. See graphic 41.

[112] Enchant Energy City of Farmington: San Juan Generating Station Carbon Capture – Final FEED Presentation, FE0031843. Graphic 42.

[113] Selch, J. et. al., *Large-Scale Commercial Capture Retrofit of the San Juan Generating Station*, FOA-0002058, Carbon Capture Front End Engineering Studies and CarbonSafe 2020 Webinar, August, 2020.

[114] The Shand SSC Feasibility Study: Public Report, International CCS Knowledge Center, November 2018, P. 115.

[115] Ibid.

Basin Electric/Dry Fork. This 440 MW (net) unit is the subject of a FEED study of the MTR Polaris membrane CO_2 separation technology. Activities at this site initiated in 2017, as part of the Wyoming CarbonSAFE studies, to determine the feasibility of nearby saline reservoirs (within 10 miles) for sequestration. A FEED study was completed in 32 months, ending June 2022. Per recommendation by S&L, MTR is constructing a 10 MW pilot plant to refine the process design. Pending these pilot plant results and project commitment decisions, detailed design is projected to start July 1, 2025, with construction completed to enable CO_2 delivery and injection by December 2029.

Summary: As site characterization for sequestration initiated in March 2017, a 12-year project duration is projected for this activity, *pending success with pilot plant results*.

Minnkota Power/Milton R. Young. Figure A-2 in Appendix A presents a timeline for activities from process feasibility to CO_2 injection, for retrofit of Fluor's Econamine FG Plus[SM] process to flue gas generated from 477 MW(net) Unit 2 and 230 MW (net) Unit 1, with sequestration at the plant site. Activities initiated in 2015, consisting of evaluating terrestrial characteristics affecting CO_2 sequestration, and pilot plant tests in the host unit flue gas to determine the longevity of amine sorbents. Subsequent work was a pre-FEED study in 2017, followed by a full FEED initiating in 2018 and completed in mid-2022.

Pending an affirmative financial investment decision in early 2024, process engineering will initiate, consisting of vendor solicitation, review, and contract award. A 42-month period is reserved for construction, shakedown testing, and CO_2 injection by year-end of 2028.[116] Permits for CO_2 injection wells in North Dakota is enabled by the states authority to permit geologic carbon sequestration facilities as Class VI injection wells under the Safe Drinking Water Act's (SDWA) Underground Injection Control (UIC) program.

Summary: This 12-year timeline reflects work directed for CCUS technology demonstration; there are limited opportunities to compress this schedule.

Prairie State Generating Station. Prairie State Generating Company was host site for a FEED study of CCUS on one of the 816 MW (gross) units, Unit 2. The analysis has produced a conceptual design and construction plan for the MHI KM-CDR process, as tested by the Petra Nova project. The Prairie State FEED study application was distinguished from previous application due to the type of coal being utilized and the size of the unit.

This project timeline is defined by both CO_2 capture studies, final design, and construction/commissioning, as well as evaluation of sequestration options in the Illinois Storage Corridor.[117] Also, as addressed in Section 5, CO_2 pipeline permitting issues are likely to be encountered, based on early observations of Illinois experience.

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[116] As described in comments to this rulemaking docket by Otter Tail Power, work to characterize the Milton R. Young site built upon work by the University of North Dakota Energy and Environmental Research Center.
[117] Greenburg, S., *Illinois Basin Decatur Project, Assessment of Geologic Carbon Sequestration Options in the Illinois Basin: Phase III*, DOE DE-FC26-05NT42588, July 7, 2021.

The Illinois Basin-Decatur Project – conducted by the Midwest Geological Sequestration Consortium[118] – explored sequestration options that could be utilized by source in Illinois, including Prairie State. These activities, conducted independently of Prairie State, initiated in 2007 as an early element of the Illinois Storage Corridor project. The results identified potential sequestration options for up to the 6 million tonnes /year of CO_2 generated by Prairie State.[119] The original scope of the FEED study of the MHI KM-CDR CO_2 capture process required 23 months (February 2020 through December 2021). The FEED study was then extended by six months, to June 30, 2022. The final phase of detailed engineering, procurement, and construction, described in Figure A-3 of Appendix A, was originally estimated to require 3.75 years. This work has not commenced.

Summary: The timeline for sequestration options and acquiring CO_2 pipeline permits within the Illinois Storage Corridor will require further evaluation and analysis. As reported in their comments submitted as part of this rulemaking, a timeline representing Prairie State project conception to CO_2 injection for sequestration is anticipated to require as much as eight to ten years.

San Juan Generating Station. Enchant Energy proposed to acquire the San Juan Generation Station in 2022, and deploy CCUS to Units 1 and 4, totaling 877 MW(net) capacity. A preliminary FEED study was completed evaluating retrofit of the MHI process to these western bituminous coal-fired units. This study was conducted from 5/22/2020 through 10/29/2021. Subsequently, a FEED study addressing engineering, procurement, and a preliminary evaluation of construction requirements was initiated in October 2022. The resulting schedule describes construction initiating in early 2024 and being completed in mid-2026, followed by commissioning and testing, enabling commercial duty in September 2027.

This work included an early permit for CO_2 pipeline to access to Cortez EOR pipeline; permitting activity was not completed.

Summary: This project – absent final permitting for a 21-mile pipeline – as planned would require 7.25 years without pipeline construction supporting access to EOR, or CO_2 sequestration site injection.

Shand. A general discussion of Shand states a project investment decision for 2029 CCS duty should be made in 2024/2025; presumably this investment decision is predicated upon a satisfactory FEED-type study to "de-risk" the decision. This FEED study is projected by Sask Power to require 18 months; accelerating the "start" of activities to 2022/2023. No discussion of CO_2 disposition actions is addressed; a pipeline of approximately 20 miles is required for Shand to deliver CO_2 to the Boundary Dam site for forwarding to the Weyburn fields for EOR.

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[118] Illinois Basin Decatur Project: An Assessment of Geologic Carbon Sequestration Options in the Illinois Basin: Phase III, DE-FC26-05NT42588, July 7, 2021.
[119] Whitaker, S., Illinois Storage Corridor: Phase 3 CarbonSafe, Update Meeting, November 9, 2021.

Summary. The projected schedule for FEED study through CO_2 delivery per Shand owners appears to be 6-7 years. The final timeline would be determined by any additional work to assure the Weyburn oilfield can effectively utilize the additional CO_2 for EOR, or to open new EOR activities in other nearby regional oil fields and construction and permitting of the pipelines.

7 EPA-PROJECTED CCUS INSTALLATIONS

EPA in the 2023 Integrated Baseline Analysis projects that 39 coal-fired units will adopt CCUS by 2030.[120] The basis for the projection is limited to the IPM model selection of units – based on approximate operating characteristics assigned to each unit – to match the required generation. Table 7-1 identifies these units, which are exemplary only and assigned no significance.

Table 7-1. Units Projected by EPA IPM to Adopt CCUS by 2030

State	Unit ID	Plant Name	Capacity (MW)
Alabama	4	James H Miller Jr	477
Arizona	3,4	Springerville	2 x 281
Colorado	3	Comanche (CO)	501
Colorado	1	Pawnee	0
Florida	BB04	Big Bend	292
Illinois	41	Dallman	135
Illinois	1, 2	Prairie State	2 x 851
Indiana	1, 2	Gibson	2 x 427
Kentucky	2	East Bend	399
Kentucky	1, 2	H L Spurlock	207, 353
Kentucky	4	Mill Creek (KY)	324
Michigan	3, 4	Monroe (MI)	2 x 528
Montana	PC1	Hardin Project	65
North Dakota	1, 2	Antelope Valley	2 x 289
Ohio	2	Cardinal	2 x 407
Texas	BLR2	J K Spruce	538
Texas	1, 2	Oak Grove (TX)	2 x 573
Utah	1, 2, 3	Hunter	320, 292, 314
West Virginia	3	John E Amos	515
West Virginia	1, 2	Mitchell (WV)	2 x 538
Wyoming	1	Dry Fork Station	253
Wyoming	BW73, 74	Jim Bridger	2 x 354
Wyoming	1, 2, 3	Laramie River	3 x 385
Wyoming	3, 1	Wygen 1, 2	53, 56
Wyoming	1	Wygen III	63

[120] EPA 2023 Integrated Baseline Analysis

A detailed critique of EPA's analysis is submitted to this rulemaking docket as part of comments by the Power Generators Air Coalition and the American Public Power Association.[121]

Figures 7-1 and 7-2 depict the location of each of these generating units – "hypothetically" assigned CCUS by the EPA IPM model - on a continental map. Also shown are boundaries for four categories of geologic sequestration (active EOR, deep saline formations, oil and gas reservoirs, and unmineable coal seams), and existing CO_2 pipelines. Each plant is encircled showing a radius of proximity to the sequestration sites or existing pipelines for EOR. Figure 7-1 shows the radius of 100 km and Figure 7-2 shows the radius of 200 km. The cited range of 100 km and 200 km are examples only, and do not represent a recommended or "default" distance for sequestration or EOR access.

[121] Technical Comments on the U.S. Environmental Protection Agency's Integrated Planning Model's Evaluation of the Greenhouse Gas Standards and Guidelines for Fossil Fuel-fired Power Plants – Proposed Rule, prepared by James Marchetti, August 7, 2023.

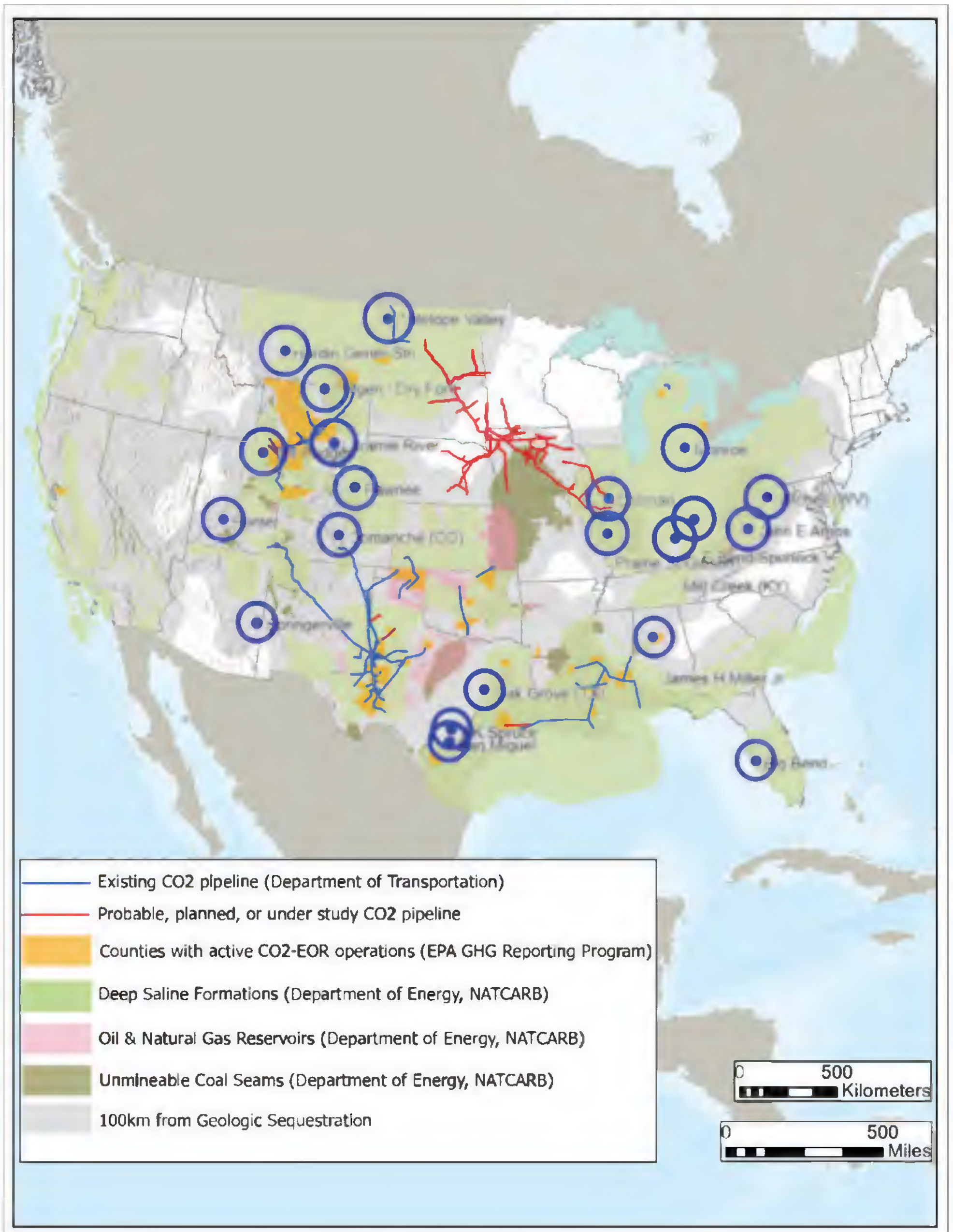


Figure 7-1. Geographic Location of Coal-Fired Generating Units EPA Projects to Retrofit CCUS: 100 km Proximity

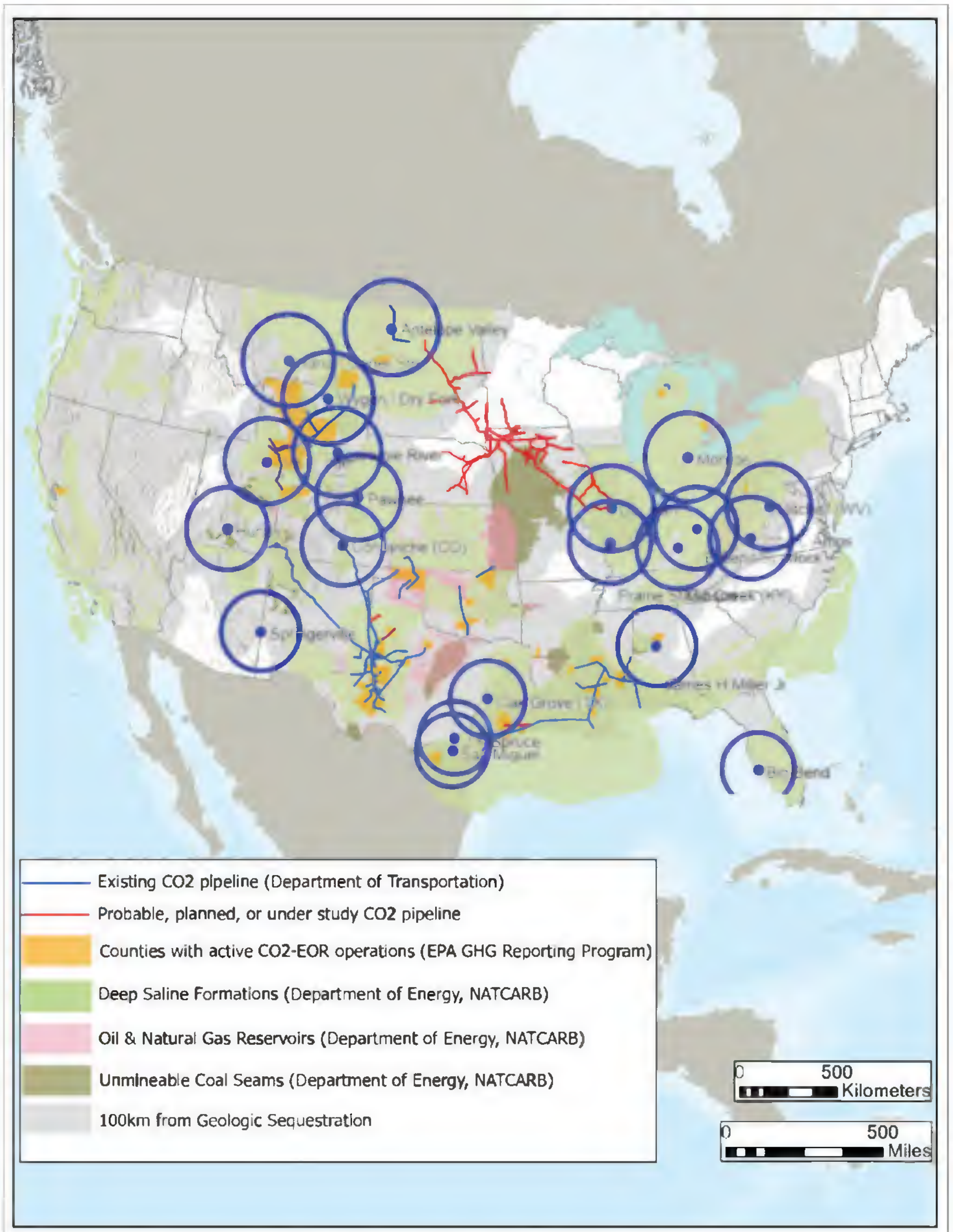


Figure 7-2. Geographic Location of Coal-Fired Generating Units EPA Projects to Retrofit CCUS: 200 km Proximity

Appendix A. Flawed Cost Extrapolations for NGCC Application

EPA projects capital, fixed operating, and variable operating costs for small combustion turbines by extrapolating results from three NETL reports. These reports define CCUS cost for coal,[122] combustion turbines,[123] and describe a methodology for scaling costs.[124] Each step in the extrapolation removed from a specific design and cost estimate compounds the uncertainties of each singular estimate. Consequently, confidence in these costs is low. The shortcomings to this approach are attributable to EPA's misuse of the power-law relationship and selection of scaling exponents, described below.

The general approach employed by NETL and accepted by EPA – use of a power scaling law to project cost to conditions other than the reference case – is valid when used within the range recommended, and the scaling "exponents" are appropriate. The NETL guidelines are not observed, as EPA employs the power-law relationship to extrapolate costs over a range of CO_2 mass and gas processing rates that vary by up to a factor of 6.

NETL issued Scaling Quality Guidelines[125] in 2013, which describes the conventional power law equation follows:

$$SC = RC * \left(\frac{SP}{RP}\right)^{Exp} \qquad \text{(Equation A-1)}$$

Where:
Exp: Exponent
RC: Reference Cost
RP: Reference Parameter
SC: Scaled Cost
SP: Scaling Parameter

Notably, NETL warn in the 2013 *Scaling Quality Guidelines* that generalizing results to process conditions significantly different from the reference design case can significantly alter the result. EPA's range of partial treatment and different CO_2 gas content between coal and NGCC CCUS represent a significant departure from reference case conditions.

---

[122] 2020 Baseline CCUS Costs.
[123] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,* DOE/NETL - 2023/4320, October 14, 2022.
[124] *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO2 Capture Rate in Coal-Fired Power Plants,* DOE/NETL-2019, December 23, 2020.
[125] 2013 Scaling Quality Guidelines.

NETL in their 2013 *Scaling Quality Guidelines* advise caution in the use of power law relationship to scale costs. Specifically, NETL cite:

There are limitations on the ranges that can accurately be addressed by the scaling approach. There can be step changes in pricing at certain equipment sizes that may not be captured by the scaling exponents. Care should be taken in applying the scaling factors when there is a large percentage difference between the scaling parameters. This is particularly true for the major equipment items. For example, it is known that the combustion turbine is an incremental cost and is specific to one level of performance.[126]

NETL advise exponents for use in scaling CO_2 flue gas treatment technology. The specific methodology EPA elected in this rulemaking differ from the NETL approach, thus scaling exponents differ. However, what does not differ is a limit in the range of flue gas processed beyond which errors are introduced. NETL advise in Exhibit 2-17 the range of the lb/hr of CO_2 removed for which the power-law methodology to scale a "CO_2 Removal System" is valid – specifically citing 445,000-689,000 lb/hr. Notably, this is less than a factor of two variance. EPA's extrapolations violate this recommended range.

[126] Ibid. page 14

Appendix B. Example CCUS Project Schedules

Figure B-1. Elk Hills Project Schedule: Post-FEED Study Activities [127]

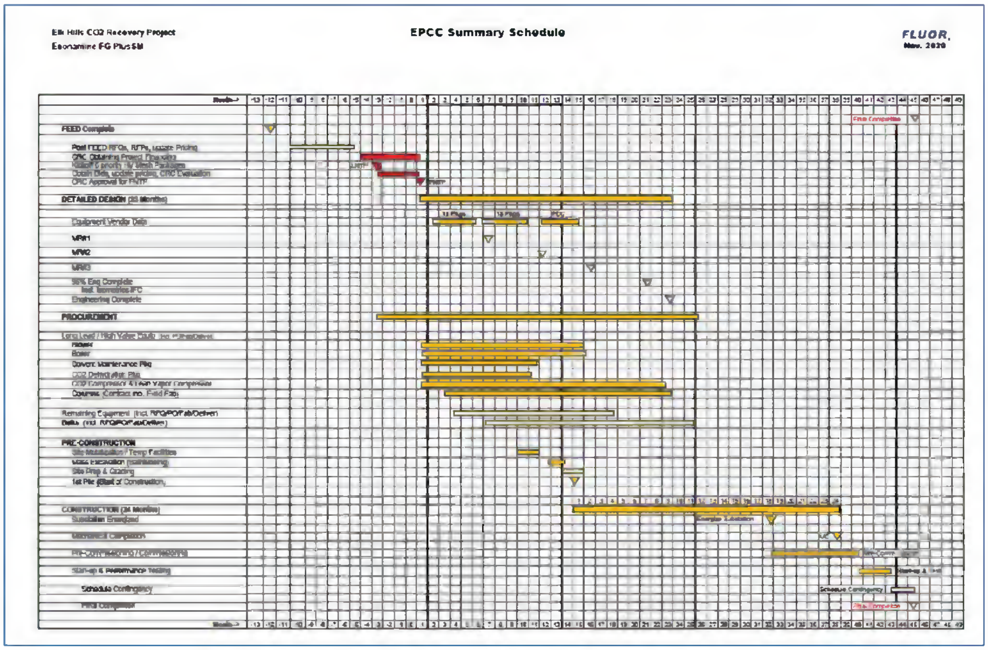
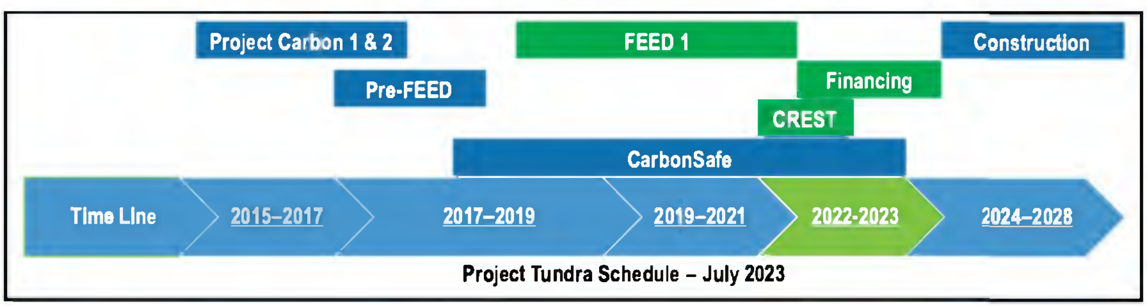


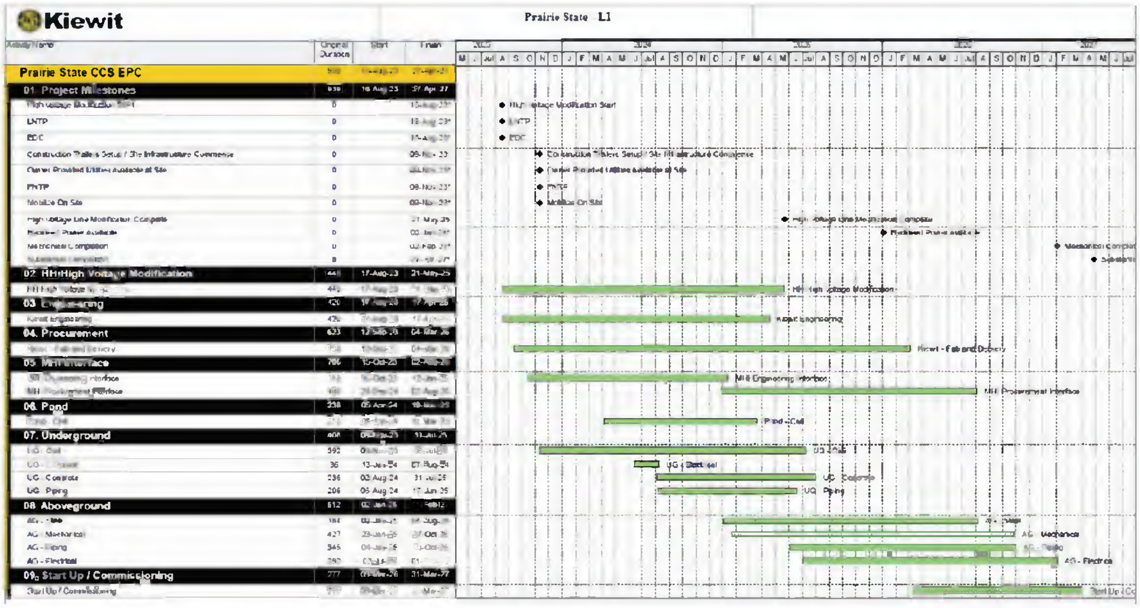
Figure B-2. Minnkota Power Milton R Young Station: Complete Schedule [128]



[127] 2022 Elk Hills FEED Report.

[128] Mikula, S, Personal Communication, July 25, 2023.

Figure B-3. Prairie State Final Engineering, Procurement, Construction Schedule [129]



[129] 2022 Prairie State Close Out. At 41.

Appendix 20

EXAMINATION OF EPA'S PROPOSED EMISSION GUIDELINES UNDER 40 CFR PART 60

Final Report

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August 2023

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EXAMINATION OF EPA'S PROPOSED EMISSION GUIDELINES UNDER 40 CFR PART 60

EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) is proposing new emission guidelines for CO_2 at existing fossil fuel-fired electric generating units. The guidelines propose that the best system for emission reduction for coal-fired electric generating units is carbon capture and storage (CCS). Carbon capture rates must meet a minimum of 90%. EPA believes that CCS is a mature technology that can be implemented to meet a 2030 deadline.

Examples are given in the guidelines to show the maturity of CCS; however, these examples spotlight facilities that are small in size, and all but two examples, Saskpower's Boundary Dam Unit 3 and the Petra Nova project, perform no subsurface injection at all. The examples are of slipstream systems and production facilities. No example is given of a facility larger than Petra Nova's 240-MW facility capturing CO_2 and injecting it into the subsurface because one does not exist.

With respect to the transport and storage of CO_2, sufficient demonstration of CCS with all the appropriate regulatory frameworks in place has not occurred. Documentation is not present to support EPA's geographic analysis, and the information the Agency does possess is out of date.

The timeline for implementation of CCS is expected to take much longer than anticipated by EPA. One example is EPA review of UIC (underground injection control) Class VI permits. In the last year, the number of permits under review has risen from 9 to 98, and historically, it appears the process can take more than 6 years per permit. Overall, from evaluation to commercial operation, an optimistic timeline indicates it can take at least 7 years to complete. Any disruptions to permitting, design, or construction can extend this for many additional years, which will be incompatible with meeting compliance in 2030.

Costs related to CCS can vary widely depending on conditions at the location and the permitting required. Based on experience, the costs to design and construct the carbon capture facility can exceed $1 billion. The pipeline for transportation of the CO_2 to the injection site can cost $600,000–$2,500,000 per mile or more, with development of the injection site costing $30 million or more, depending upon the number of injection and monitoring wells required. As a result of these substantial costs, final investment decisions on the construction and commissioning of carbon capture and transportation systems are often contingent upon an associated geologic storage facility permit being available and approved. This further extends the time to implement new carbon capture and storage well beyond the proposed compliance date.

Although CCS technology is progressing, it is too early to label it as commercially mature technology, and more projects need to be completed to substantiate the performance levels suggested by EPA. Based on the supported conclusions and the current status of carbon capture technology, EGUs cannot meet the CO_2 capture rates or the timeline that EPA proposes.

EXAMINATION OF EPA'S PROPOSED EMISSION GUIDELINES UNDER 40 CFR PART 60

INTRODUCTION

The proposed change to the U.S. Environmental Protection Agency's (EPA's) rules within 40 CFR Part 60 details proposed carbon emission standards for both fossil fuel-fired steam generating units and fossil fuel-fired stationary combustion turbines. In this document, EPA outlines climate change and its impacts; recent developments in emissions; proposed requirements for both new and reconstructed stationary combustion turbine electric generation units (EGUs); requirements for new, modified, and reconstructed fossil fuel-fired steam generating units; the proposed regulatory approach for existing fossil fuel-fired steam generating units; the proposed regulatory approach for emission guidelines for existing fossil fuel-fired stationary combustion turbines; and impacts of the proposed actions. Within the document, EPA discusses the best system of emission reduction (BSER) for various subcategories of fossil fuel-fired steam generating units and subcategories of fossil fuel-fired stationary combustion turbines. The primary focus of this review is to examine the application of carbon capture and storage (CCS) technologies to these EGUs through their present state of readiness and adequacy of demonstration. CCS includes the carbon capture process itself, transportation of the CO_2, and storage or sequestration.

SUBCATEGORIZATION OF ELECTRIC GENERATION UNITS

The EPA categorizes EGU's into two primary groups: fossil fuel-fired steam generating units and fossil fuel-fired stationary combustion turbines. Various subcategories exist under the umbrella of these two categories, which are further discussed below.

Of the eleven subcategories for fossil fuel-fired steam generating units, EPA is proposing the application of CCS to one: long-term existing coal-fired steam generating units. These units are coal-fired steam generating units that have not elected to commit to permanently cease operations by January 1 of 2040. This CCS system is required to have a CO_2 capture rate of 90%, with the associated degree of emission limitation a CO_2 reduction of 88.4% lb CO_2/MWh-gross (proposed rule pages 33359 and 33360).

EPA is proposing to regulate existing fossil fuel-fired stationary combustion turbines in two segments, with only the first outlined in this proposed EPA regulation, the second to be released in a separate regulation document later. In this first segment, EPA proposes regulation for baseload turbines over 300 MW. EPA defines baseload as having a capacity factor greater than 50% (proposed rule page 33362).

EPA believes that two technologies are possible BSERs for fossil fuel-fired stationary combustion turbines over 300 MW operating at a capacity factor of greater than 50% coupled with heat-rate improvements: i) cofiring with low greenhouse gas (GHG) hydrogen and ii) CCS. EPA believes that the 300-MW threshold for applicability is appropriate because it focuses on the units with the highest emissions where CCS is likely to be the most cost-effective.

ADEQUACY AND APPLICABILITY OF CARBON CAPTURE

Several technologies are included under the umbrella of carbon capture: postcombustion, precombustion, oxyfuel combustion, and direct air capture. Direct air capture does not capture CO_2 directly from a GHG point source prior to its emission but after. Therefore, direct air capture is not further discussed, as it is not applicable to being integrated into fossil fuel-fired steam generating EGUs or fossil fuel-fired turbines.

Oxyfuel combustion involves combining a fuel, such as coal or natural gas, with pure oxygen. Since the oxidant stream is pure oxygen instead of air, such as in a conventional combustor, the combustion reaction does not create other combustion by-products such as NO_x. CO_2 and H_2O steam are produced from the reaction, which is then used to power a turbine. Since this combustion reaction creates a stream of pure CO_2, the CO_2 can be captured without the need for additional systems that are required in pre- or postcombustion CO_2 capture. However, these systems do require a constant and sizable supply of pure oxygen, often necessitating an air separator to be included in the process (1). Additional challenges of oxyfuel combustion systems are the high capital costs, energy consumption, and operational challenges of oxygen separation (2). Research of oxyfuel combustion is still ongoing, with projects focusing on lab-, bench-, and pilot-scale testing to understand the combustion mechanics of oxyfuel combustion at high temperatures and pressures, verify system design and operation concepts, and improve the performance of ancillary system components (3). Some demonstrations of oxyfuel combustion systems have been conducted, the largest being a retrofitted 100-MWth PC boiler in Central Queensland, Australia, which operated from December 2012 to March 2015. In that time, the unit achieved 10,000 hours of oxyfuel combustion and 5500 hours of carbon capture (4).

Precombustion CO_2 capture constitutes the removal of CO_2 from a fuel source prior to its combustion. This is commonly achieved through fuel gasification, in which the feedstock, such as coal, is partially oxidized with steam and oxygen-rich air under high temperature and pressure to form syngas, which is a mixture of hydrogen, carbon monoxide, CO_2, and smaller elements of other gases, such as methane. The syngas can then undergo the water-gas shift reaction, which converts the carbon monoxide and water in the gas to hydrogen and CO_2. The CO_2 can then be captured, and the H_2-rich fuel combusted. Since the precombustion fuel stream is rich in CO_2 and at a higher pressure, extraction of the CO_2 from the stream is easier than in postcombustion systems. However, the cost of a gasification system is often greater than a traditional coal-fired power plant (5). Therefore, precombustion CO_2 capture is not considered a leading technology for CO_2 emissions reduction in the electrical generation industry. But it has been shown to be effective in the chemical processing industry, with Great Plains Synfuels Plant in Beulah, North Dakota, having been in operation for the past 25 years and remaining the only coal-to-synthetic natural gas facility in the United States. Great Plains Synfuels Plant produces synthetic natural gas from lignite coal and captures its CO_2 for utilization in enhanced oil recovery (EOR) in Canada. The plant is capable of capturing up to 3 million tons of CO_2 per year. Since 2000, CO_2 emissions at the Synfuels Plant have been reduced by 45% (6).

Postcombustion CO_2 capture involves the removal of CO_2 from the flue gas of an EGU. After the fuel has been combusted, the exhaust gases are processed to filter out potential contaminants such as ash and SO_2, then the exhaust gases go to the postcombustion CO_2 capture system, which captures the CO_2 from the gas stream through a reaction with a chemical solvent (amine). This solvent captures the CO_2 gas, and the solvent and gas are later separated in the stripper column, where heat and pressure are used to regenerate the solvent and create a stream of pure CO_2, that can then be compressed, transported, and sequestered. The use of chemical solvents for carbon scrubbing is the most commonly acknowledged process for capturing CO_2 from gas mixtures (7) and has been used in the natural gas industry to separate CO_2 from other gases since the 1930s (8). Current federally funded work in solvent-based postcombustion capture is seeking to address key challenges to deployment, which include scale-up, parasitic load, process integration, water use, and capital costs (8). Additionally, solvent degradation can be a significant issue.

The large-scale carbon capture facilities that are in operation throughout the world are mostly focused on natural gas processing (9). Only two facilities are operating at coal-fired power plants: Saskpower's Boundary Dam Unit 3 (110 MW) and the Petra Nova Project (240 MW equivalent), which will be discussed later. Postcombustion CO_2 capture has yet to be demonstrated at a baseload facility larger than Boundary Dam Unit 3. Parasitic load requirements for the operation of the carbon capture system decrease the net power output of the EGU by roughly 20% (10).

With respect to carbon capture technology, the proposed rule states that:

> *"The EPA is proposing that the CO_2 capture component of CCS has been adequately demonstrated and is technically feasible based on the demonstration of the technology at existing coal-fired steam generating units..." [page 33291]*

The design and integration of CO_2 capture facilities can vary based on the configuration of the EGU and fuel source. Variations, such as the CO_2 purity of the emission stream, facility design, local energy costs, emission volumes, flue gas temperature and pressure, the presence of contaminants, transition from cold or warm (standby) condition to operation condition, and ramping due to load changes, all affect the applicability and cost of implementing CCS at fossil fuel-fired EGUs (11). For example, in Wyoming, most of the existing power generation fleet is not equipped with environmental control systems that remove enough NO_x, SO_x, and other air pollutants to prevent the accelerated degradation of the amine solvent inside of the CO_2 capture system. 87% of EGUs have flue gas desulfurization systems, and 56% of EGUs have postcombustion NO_x control systems, whereas nearly all Wyoming EGUs only have particulate and mercury control devices installed. Before a CCS system could be constructed and retrofitted, these facilities would need to be upgraded to meet these requirements (12). These upgrade requirements are not considered by EPA in the proposed capture requirements.

Typical solvents utilized in carbon capture systems are amine-based. The name amine refers to a chemical function group that includes compounds with a nitrogen atom and a lone pair. A common amine in CCS systems is monoethanolamine (MEA), colloquially referred to in industry as amine. Amines are susceptible to degradation, and solvent management can be a significant challenge. Amine degradation can reduce solvent efficiency or cause an unintentional release into the atmosphere. This degradation can happen because of several factors: thermal or oxidative degradation or reaction with impurities in the flue gas stream. Advanced amines are being developed, which reduce thermal or oxidative degradation of the amine and improve its capture efficiency; however, impurities still have a significant impact on the life of amine.

Thermal Degradation

The heat involved in the regeneration process, where CO_2 is stripped from the amines, can cause these molecules to break down, leading to loss of capture efficiency and the need for frequent solvent replacement. This aspect is poorly addressed in literature due to the sensitive nature of sharing specific information from vendors. This quickly increases operating costs and results in large quantities of liquid waste. The EPA does not recognize or address this issue.

Oxidative Degradation

The solubility of oxygen in amine solutions is a key issue in dealing with problems like degradation and corrosion (13). An increased level of oxygen in the amine solvent changes the solvent chemistry, increasing its tendency to cause oxidation and corrosion. The Technology Centre Mongstad (TCM) studied amine degradation in a combined heat and power plant (CHP) and noted significant corrosion. Significant material thickness reduction and leakage on the CHP reboiler heat exchanger plates were observed. The CHP stripper packing surface was coated by a layer of corrosion products. This layer was "leaching" out in the solvent upon restart of the CHP stripper, resulting in rapidly increasing iron content in the fresh solvent (14). The application of an oxygen scavenger, a chemical additive to the amine solvent, could be used as a preventive measure to keep solvent degradation low. This form of degradation of the amine solvent is correlated to the composition of the EGU's flue gas and not the capture rate of the CCS system; therefore, the effects of the flue gas on the solvent chemistry must be individually investigated at each facility.

Degradation by Reaction with Impurities

When TCM tested amines on a residue fluidized catalytic cracker (RFCC), they had not been able to operate the amine plant with RFCC flue gas because of very high amine emissions (>20 ppm) caused by sulfuric acid aerosol and dust particles present in the flue gas (15). With installation of a Brownian diffusion (BD) filter upstream from the absorber, more than 95% of the aerosols were removed, and together with optimization of plant process parameters and configuration, the amine emissions were reduced. It is known that both SO_2 and NO_x will give unwanted reactions with MEA (16).

Although the degradation mechanisms for MEA have been extensively studied in the literature (16–19), testing, understanding, and mitigating amine degradation on a plant-by-plant basis are crucial for the sustainable and efficient application of CCS technology. Research is ongoing to develop advanced amines and to improve the process design to minimize amine losses, such as optimizing operating conditions, implementing solvent purification processes, and better managing impurity variability in the flue gas.

The above discussion illustrates that additional investigation is required at the specific facility being considered for installation of a carbon capture system that may include significant construction and redesign to accommodate CCS implementation.

CARBON CAPTURE EXAMPLES

EPA cites several examples of successful plant operation within its proposed guidelines, and a few of them will be briefly discussed. These examples do show that CCS is possible and promising and present a promising solution for the future; however, they 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%.

AES Corporation's Warrior Run Generating Station

The Warrior Run Station is a 180-MW bituminous coal-fired power plant located in Maryland. The installed CO_2 capture system captures a small slipstream of the facility's flue gas to produce 330 t CO_2/day of food-grade CO_2 for use in food processing. The process used is an ABB Lummus unit with MEA as its solvent (20). The installed CO_2 capture system captures anywhere between 4% to 6% of the CO_2 emissions of the plant (21). The important highlights are that the system is a slipstream of a small power plant which produces a product and does not inject CO_2 into the subsurface. Therefore, the small capacity, slipstream system employed here demonstrates a small portion of the required CO_2 capture rate and has little correlation to the levels EPA would mandate under their proposed guidelines.

AES Corporation's Shady Point Generating Station

Shady Point Power Plant is a 320-MW circulating fluidized-bed subbituminous coal-fired power plant located in Oklahoma. A slipstream of the power plant's flue gas is captured to produce 200 t CO_2/day of food-grade CO_2 for use in food processing. With the plant emitting 1.24 million t CO_2/year, the yearly capture rate approximates to 6%. This process uses an ABB Lummus scrubber system with MEA as its solvent (20). Like the Warrior Run Generating Station, this is a small slipstream which produces a product and does not inject CO_2 into the subsurface. This example has little correlation to the levels EPA would mandate under their proposed guidelines.

Searles Valley Minerals Soda Ash Plant

The Searles Valley Minerals Soda Ash Plant, located in California, captures approximately 800 t CO_2/day from the flue gas of the 62.5-MW Argus Cogeneration Plant, a subbituminous coal-fired power plant that generates electricity and steam. The CO_2 is captured with an ABB Lummus MEA capture unit, and the captured CO_2 is used for the carbonation of brine in the production of soda ash (20). With the plant emitting 1.63 million t CO_2/year, the capture rate approximates to 18%. Like the previously discussed facilities, the small capacity system employed here demonstrates a small portion of the required CO_2 capture rate and has little correlation to the levels EPA would mandate under their proposed guidelines. The correlation between this facility and what is expected under the proposed guidelines is minimal.

Quest CO_2 Capture Facility

The Quest Carbon Capture and Storage Project is a CCS facility in Alberta, Canada, that began operation in 2015. Quest removes CO_2 from the process gas streams of three hydrogen manufacturing units (HMUs), equating to 1 million t CO_2/year, within the Scotford upgrader facility, which emits 3 million t CO_2/year. Between the years of 2015 and 2021, Quest has been able to capture between 77.4% and 83% of CO_2 emissions from the HMUs, with the average CO_2 capture rate of 79.4% (22). Although the facility has demonstrated the ability to store CO_2, the overall capture rate of the facility falls short of EPA's proposed 90% minimum capture rate.

Saskpower's Boundary Dam Unit 3

Saskpower's Boundary Dam Unit 3 (BD3) is a 110-MW lignite-fired unit in Saskatchewan, Canada. Development of the CCS facility began in 2007, with the decision to move forward with construction in 2010, and provides CO_2 for both EOR and sequestration. Saskpower selected the CANSOLV process, an amine solvent system, for its CO_2 capture process. During its first year of operation, BD3 achieved a CO_2 capture rate of 50% of its designed volume. This capture rate has been improved through design and operations optimizations, although the capture rate is still below its designed CO_2 production levels. Significant issues included operational difficulties from construction and design deficiencies, issues with fly ash carryover, a lack of redundancy and isolation capabilities, and amine degradation and foaming (23). Lessons learned from this CCS facility are slow to be released, and there may be other operational challenges that industry and EPA do not know about. This facility exemplifies the site-specific challenges that are to be expected with CCS implementation and is only one-third the scale of plants that would be addressed in EPA's proposed emission guidelines.

NRG Energy's Petra Nova Facility

The Petra Nova facility, located in Texas, is a 240-MW equivalent slipstream of flue gas from the W.A. Parish coal-fired facility. This postcombustion capture facility started operation in 2017 and fulfilled its objectives of demonstrating carbon capture at this scale coupled with compression and transportation of CO_2 to an oil field for EOR only. The facility was shut down because of low oil prices in May 2020 due to no alternate method of sequestration. Market-driven EOR alone does not adequately demonstrate CCS that will meet EPA's proposed continuous emission reduction. During its 3-year operation, it suffered frequent outages and missed its carbon capture targets by ~17% (24).

AVAILABILITY FACTOR

The availability factor is a measure of the amount of time a system is in operation and not undergoing maintenance, repair, and unexpected down time and is given as a percentage. The most relevant example given by EPA for an EGU utilizing a fully integrated carbon capture system is Boundary Dam Unit 3, as mentioned above. Since its start-up in 2014, the unit has experienced operational issues that have led to more frequent capture facility outages than originally anticipated. The primary issues experienced have been with fly ash and fly ash component buildup in the CCS facility. Heat-transfer surfaces, such as the reboilers, fouled over time. The packing in the absorbers and the strippers also experienced fly ash buildup and the development of organic deposits. These issues affected the capture capacity of the facility as the heat-transfer efficiency decreased and the gas flow rate became limited because of deposits. The implementation of advanced demister wash systems has extended the facility's operational time between maintenance outages, and wash systems for the booster fan and redundant heat exchangers, with isolations, have enabled the facility to conduct online maintenance. The capture facility has also experienced compressor failures that increased its unplanned outage time for the years of 2021 and 2022. Figure 1 shows the yearly percent availability of the Boundary Dam Unit 3 capture facility's availability, planned maintenance outages, and unplanned outages for the years of 2014 through 2022 relative to the operation of the power plant (25).

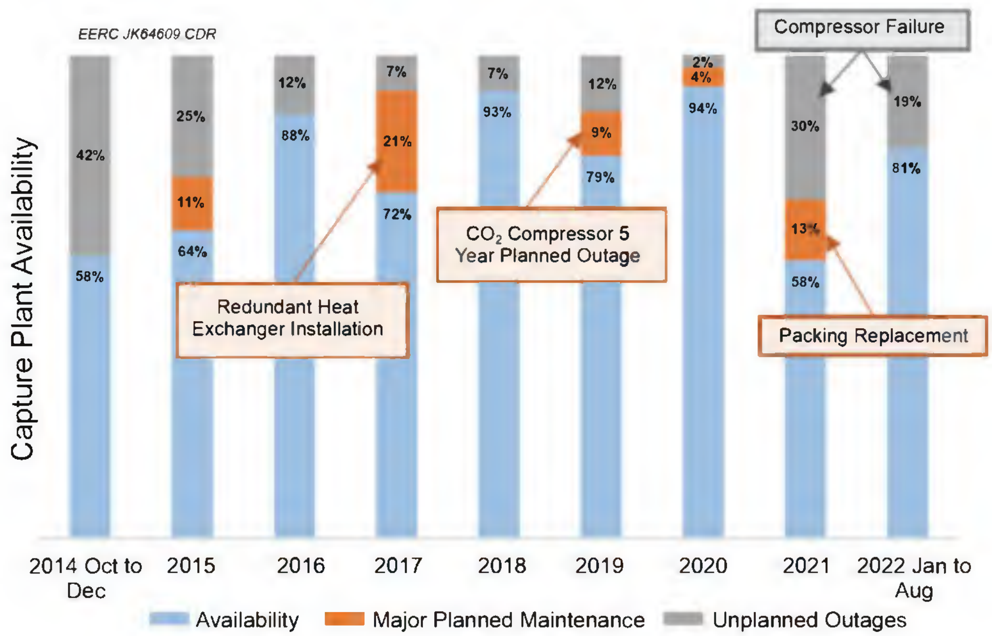

Figure 1. Availability of Boundary Dam Unit 3 capture facility and CO_2 compressor relative to the Unit 3 power plant (25).

The figure shows that annually the capture facility was not able to operate the full time the power plant was in operation and for only 2 years was the facility operating above 90% of the available time. Based on this information, even with the capability to capture greater than 90% of the CO_2 emissions, it is premature to expect that a capture facility will be able to operate with an availability factor sufficient to comply with the annual emission requirements of the proposed rule.

NATURAL GAS CARBON CAPTURE

Many of the demonstrations studied by EPA are coal-fired power plants with small slip stream CO_2 capture systems. EPA proposes CCS as the BSER for stationary combustion turbines for greater than 300 MW and over 50% capacity factor; however, CCS has been studied less at natural gas EGUs than coal-fired EGUs. Among coal-fired EGUs, each facility has different CCS retrofitting and integration needs, due to the operational parameters, facility differences, and the composition of flue gas. One of the primary challenges with natural gas is its lower carbon load. Natural gas-fired generation produces less CO_2 per MWh than coal-fired facilities, meaning that the capture plant design has to be adjusted for a lower concentration of CO_2 in the flue gas (26). Additionally, gas turbine EGUs are more likely to be throttled for load-following applications than coal-fired EGUs, adding significant demands and stresses on the attached CCS system to ramp with the power plant (27).

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

Currently, no commercial-scale IGCC plants are in operation or under development. The Kemper County, Mississippi, IGCC project struggled, with major problems stemming from overly complex technology, complex supply chain, and equipment reliability issues (28). After significant cost overruns, the original plan for a gasification plant was abandoned, and the plant was converted to natural gas operation (29).

TRANSPORTATION AND GEOLOGIC STORAGE

Several fundamental assertions are made by EPA in its proposed guidelines in relation to CO_2 transportation and geologic storage. In the following sections, those assertions will be directly addressed.

With respect to the geologic storage of CO_2, the proposed rule states that:

> *"The EPA proposes that CCS at a capture rate of 90 percent is the BSER for long-term coal-fired steam generating units because CCS is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources and that there are vast sequestration opportunities across the continental U.S." [page 33346]*

The issue is with the assertion that "CCS is adequately demonstrated" and "has been operated at scale." EPA describes in the May 23, 2023, technical support document (TSD) titled *GHG Mitigation Measures for Steam Generating Units TSD* on page 22 that there are only two large-scale CCS facilities in North America on existing coal steam EGUs. One of which was Petra Nova which only operated from 2017 to May 2020 and involved CO_2 EOR. The other is Boundary Dam in Canada, which is not subject to EPA's underground injection control Class VI rules for the storage of CO_2. To date, no commercially operated CCS project capturing CO_2 from a coal steam EGU in the United States has operated under EPA Class VI regulations. The only CCS projects that are in operation in the United States under EPA Class VI regulations are Archer Daniels Midland processing plant (capturing approximately1 million tonnes/year) in Decatur, Illinois, and the Red Trail Energy ethanol facility (capturing approximately 180,000 tonnes/year) near Richardton, North Dakota. For comparison, a 300-MW coal-fired facility would capture approximately 2.5 million tonnes/year. These two projects are not enough to demonstrate that the appropriate regulatory frameworks are in place for the operational phase of projects that will require flexibility and likely regular updates to permitted operational parameters.

Another issue is with the assertion of "vast sequestration opportunities." This assertation is seemingly founded on a geographic analysis performed by EPA:

"The EPA performed a geographic availability analysis in which the Agency examined areas of the country with sequestration potential in deep saline formations, unmineable coal seams, and oil and gas reservoirs; information on existing and probable, planned or under study CO_2 pipelines; and areas within a 100-kilometer (km) (62-mile) area of locations with sequestration potential." [page 33298]

However, no documentation of this geographic analysis is provided. The May 23, 2023, TSD titled *GHG Mitigation Measures for Steam Generating Units TSD* also referenced this geographic analysis. Figure 1 of the TSD showing geologic storage potential from the NATCARB website includes an antiquated map layer for unminable coal seams. The U.S. Geological Survey (USGS) has a more accurate map of unminable coal seams that could be used for CCS (30). The USGS map accounts for EPA Class VI regulations, 40 CFR 144.3, and 40 CFR 144.6 (31), which prohibit CO_2 storage in formations with salinity lower than 10,000 mg/L (30, 32). Figure 1 of the TSD also shows an erroneous map layer for deep saline formations. Using the correct deep saline formation map layer (showing the proper extent of assessed formations based on minimum depth requirements), the USGS coal layer, and the pertinent stationary CO_2 sources will show that the spatial relationship of CO_2 capture to geologic storage is not as opportune as suggested by EPA. The result is that more and longer pipelines will be needed to transport captured CO_2 to feasible storage locations. This implication cascades into additional time (and money) needed to construct a fully integrated CO_2 capture, transport, and storage project. Other aspects of EPA's geographic analysis that contribute to the overstatement of "vast and nearby" geologic storage opportunities are:

- Proximity does not factor into the feasibility/suitability of geologic storage.

- The EPA geographic availability analysis is based on a generation unit being within 100 km of a state with geologic storage potential, rather than from the storage location itself, which erroneously oversells the spatial relationship between CO_2 source and geologic sink.

- The analysis does not integrate evolving local (state, county, parish) CO_2 transportation and storage laws, some of which are looking to ban the geologic storage of CO_2.

In the TSD, EPA states:

"DOE's assessment focuses on the potential physical constraints for sequestering CO_2; it does not include economic or other constraints."

And

"While the NETL and USGS characterize potential storage, site-specific technical, regulatory, and economic considerations will ultimately factor into the attractiveness of a given storage resource for a particular project."

These are nontrivial comments that have a strong impact on project timelines and budgets when a geologic storage option is pursued for captured CO_2. A major consideration from a regulatory perspective is access to federally owned pore space, a topic that has yet to be fully addressed by any federal agency.

TIMING

In the May 23, 2023, TSD titled *GHG Mitigation Measures for Steam Generating Units TSD,* EPA denotes that deployment of CCS is economically reasonable and can be done within 5 years:

> *"Deployment of CCS technology at EGUs involves a project schedule that can be completed in roughly five years. For affected sources who choose to implement CCS, the project will involve several phases, many of which can occur concurrently and simultaneously." [page 35 TSD]*

> *"There are many site-specific considerations to individual sources that influence the project timeline and schedule. Nonetheless, EPA believes that a five-year project timeline for deploying CCS, and related infrastructure and equipment, is reasonable." [page 36TSD].*

This 5-year period, as depicted in the example timeline shown in Figure 2, which was also presented in the TSD, is not realistic and is completely unachievable. The timeline has several issues related to the sequencing of events, as discussed below.

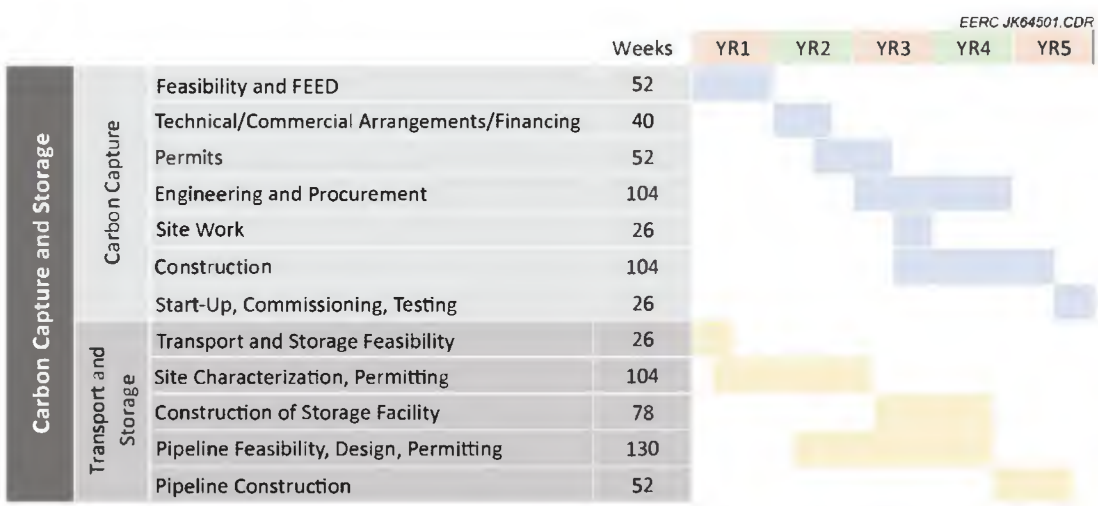

Figure 2. Timeline to storage as presented by EPA in the TSD.

Carbon Capture Timing Issues

This timeline assumes that procurement of capture equipment will be started prior to the storage site being permitted. Most facilities looking to develop CCS will be reliant on third-party financing or loans. These financing avenues have historically required permits for the storage site to be in place to increase regulatory certainty and reduce investment risks. Based on that experience, even on EPA's inaccurately short and overlapping time frames for each step, the carbon capture timelines would be delayed by at least an additional 1.5 years.

The timing of the site work and construction at the carbon capture site are shown to commence approximately 6 months after the start of engineering and procurement. Without detailed information concerning the constructability of the site such as soil analysis, location parameters (temperature changes, wind loading, etc.), the footprint of the capture facility, etc., that requires measurement and testing to provide detailed information for the construction of the capture facility, the present timeline is likely compressed and would be expected to require additional time (3–6 months) to complete the requisite evaluations prior to initiation of work.

Transport and Storage Timing Issues

The timeline shown in Figure 2 depicts 2.5 years for storage feasibility, site characterization, and permitting. This is an extremely optimistic and aggressive timeline. For example, the U.S. Department of Energy's CarbonSAFE Program assumes a 5-year timeline to address feasibility, characterization, and permitting. Even for states with Class VI primacy such as North Dakota, storage feasibility, site characterization, and permitting could take up to 4.5 years (33). One of the only ways to accelerate this timeline would be if there were existing site-specific data that were sufficient to address UIC Class VI requirements. For states without primacy, storage feasibility, site characterization, and permitting could take up to 6.5 years based on historical EPA permitting timelines from the two approved EPA UIC Class VI permits (34). In June of 2022, nine projects were waiting for Class VI permit approvals (35). EPA now has 98 UIC Class VI permits (in 35 projects) to review (36).

Another issue with the proposed 5-year timeline is that it does not adequately factor in the time needed to lease pore space. Much of the prime geologic storage opportunity lies beneath federally owned lands. As such, any storage operation that will emplace captured CO_2 in pore space managed by the federal government will need to work through federal permitting and NEPA (National Environmental Policy Act) review. This process alone can add years to a project's development timeline. In addition to the federal land issue, many states have yet to address pore space ownership. Challenges to amalgamation authority on nonfederal land, achieving 100% consent of private pore space owners where amalgamation rules do not exist, and states lacking established pore space rules result in significant uncertainty regarding how much of the nation's geologic CO_2 storage resources can be developed and permitted, particularly within the time frame of the proposed rules.

Pipeline feasibility, design, and permitting stage is listed at 2.5 years. Depending on the route of the pipeline, permits for water body crossings, federal lands, and the Army Corps of Engineers can take a year or more to acquire, if the permit is allowed at all. In addition, agreements with landowners for rights of way (ROWs) for the pipeline can take a year or longer, depending on the length of the pipeline. In all, the listed time of 2.5 years for pipeline feasibility, design, and permitting appears to be overly optimistic. In addition, with the current supply chain issues, the ability to secure the required piping and equipment may take up to 1 year to acquire. With multiple major projects planned to be undertaken, supply chain issues would be expected to worsen. Finally, as the number of projects grow, the demand for labor will increase, adding to the expected cost.

A subsidiary supporting attachment provided by EPA to augment the *GHG Mitigation Measures for Steam Generating Units TSD* entitled "CCS Schedule Sargent and Lundy" contains the development timeline in Figure 3. As stated in the supporting document, "This schedule is for the on-site CCS system only and does not include the scope associated with the development of the CO_2 off-take/storage (including transportation, sequestration, EOR, utilization, and/or utilization)." Although the 7-year schedule shown in Figure 3 is quite aggressive, it is more realistic than the EPA's schedule shown in the upper part of Figure 2. There is no explanation as to why EPA chose to arbitrarily dismiss this timeline in favor of one that seemingly fits its regulatory goals better.

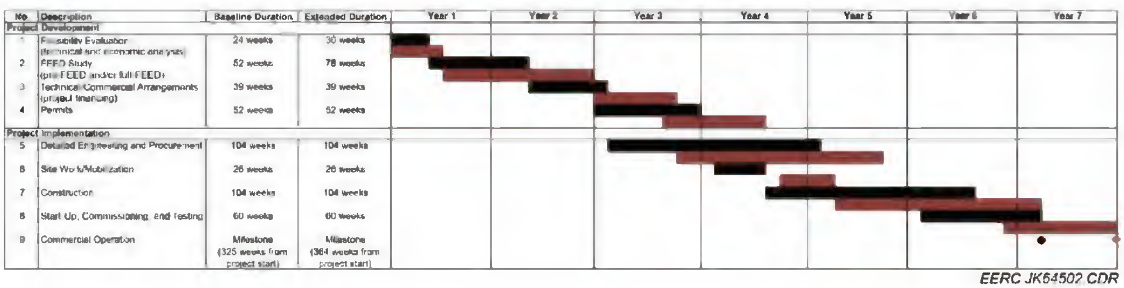

Figure 3. More realistic development timeline for the capture portion of a CCS project.

COSTS

It is difficult to give precise costs for a CCS project because of the factors outlined above and the specific needs of a specific facility to achieve a minimum of 90% CO_2 capture. It has been our experience that the general range for the capture facility at EGUs alone is \$0.8–\$1.3 billion. In determining the needs for CO_2 transportation, a "rule-of-thumb" (ROT) estimate for the installed cost of a pipeline can be calculated with the following expression:

Installed Cost = Pipe O.D. (inches) × Pipeline Length (miles) × \$100,000

This ROT estimate is a based on the FECM/NETL CO_2 Transport Cost Model (2022) (Model), where the installed cost reflects 2019 dollars and is based on the Parker equation within the central U.S. region, referenced within the Model. Pipelines in other areas as well as any pipeline specific needs (environmental impacts, water body crossings, large elevation changes, etc.) would need to be addressed in addition to the estimated costs provided by the Model. The Model reflects costs for new pipeline installations and reflects the steel pricing used within the model. If the pricing of steel for the pipeline under consideration is different than the pricing included in the Model, the Model would need to be adjusted to reflect the current pricing or additional cost included to reflect the anticipated pricing.

EPA references $280K per inch-mile for pipeline installations and states that is the cost "to construct new natural gas pipelines ("laterals") and is an average for lateral development within the contiguous U.S." (page 33353). The term "lateral" typically refers to a line that delivers product from a main line to a customer. As such, the installation of a lateral will normally include costs such as hot tapping of the main line to install the lateral offtake, potentially shutting down the main line to install the lateral offtake, etc. These are high-cost projects and are not typically included in new pipeline construction.

From our experience in CCS field development, using an example of one injection well with one monitoring well, assuming the CO_2 is at pressure and not requiring additional pressurization at the injection pad, and injecting 1 million metric tons of CO_2 per year, the cost of injection field development surpasses $30 million. Additional injection and monitoring will cause this value to quickly increase. Also, the need for premium casing such as corrosion-resistant alloys (CRAs) can add substantial cost to the drilling costs associated with the injection and monitoring wells necessary for the project. In addition, the lead time for the CRA material can be 1 year or longer. If material testing is required to determine which CRA would best serve the system, the time to design, perform, and evaluate the material tests can require 6 to 12 months (depending on the number and types of materials for testing) before the CRA material can be purchased. Given the wide range of CO_2 streams from the EGU and other facilities, different targeted injection horizons, and very little information available on CRA testing in saline environments with CO_2 streams with multiple impurities, it is anticipated that material testing would be required to determine which CRA material would be required. The effects that the material testing needs and the availability of CRAs would have on a project are not evident in EPA's consideration.

SUMMARY

Although CCS technology is progressing, it is too early to label it as commercially mature technology, and more projects need to be completed to substantiate the performance levels suggested by EPA. No large-scale (greater than 240-MW) CCS systems on EGUs are in operation in the United States by which to determine the feasibility of CCS as a BSER option. Each facility's design considerations are unique and can vary widely due to variables such as the CO_2 purity of the emission stream, facility design, local energy costs, emission volumes, flue gas temperature and pressure, the presence of contaminants, transition from cold or warm (standby) condition to operation condition, ramping due to load changes, and the required purity of the CO_2 emission stream. When examining the case of Boundary Dam Unit 3 capture facility's availability factor, since the start of operation, the expectation of a capture facility to operate long enough through the year to meet EPA's proposed annual emission requirements has fallen short, and there is no expectation that facilities in the United States will not see similar issues. The EPA storage assumptions are not adequately documented, and the complexity of the permitting required will greatly affect timelines for facilities to implement CCS. Based on the supported conclusions and the current status of carbon capture technology, EGUs cannot meet the CO_2 capture rates or the timeline that EPA proposes.

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Appendix 21

August 8, 2023

Via Federal eRulemaking Portal www.regulations.gov

Docket ID No. EPA-HQ-OAR-2023-0072-0001

The Honorable Joseph Goffman
Principal Deputy Assistant Administrator
Office of Air and Radiation
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Subject: NET Power's Comments on EPA'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"

Dear Principal Deputy Assistant Administrator Goffman:

NET Power appreciates the opportunity to submit the following comments in response to the U.S. Environmental Protection Agency's ("EPA") 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" ("Proposed Rule").[1] NET Power's comments provide information related to the scalability of the NET Power Cycle technology within the time frame for Best System for Emissions Reductions ("BSER") for new gas-fired electric generating units.

The NET Power Cycle could play a significant role in reducing emissions from the electric power system by providing reliable, affordable, and clean baseload power generation from natural gas while avoiding carbon dioxide ("CO_2") emissions. EPA recognized as much when it acknowledged the NET Power Cycle in its proposal and, previously, in its draft White Paper on reducing GHG emissions from gas EGUs.[2]

[1] 88 Fed. Reg. 33240 (May 23, 2023) [hereinafter Proposed Rule].
[2] Proposed Rule at 33292 ("Potential advantages of this cycle are that it emits no NO_X and produces a stream of high-purity CO_2 that can be delivered by pipeline to a storage or sequestration site without extensive processing."); EPA, White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units 41 (Apr. 21, 2022) (similar).

NET Power submits these comments to provide regulators and the public with additional information about NET Power and the NET Power Cycle. These comments also provide information and data regarding the timeline of the NET Power Cycle's availability. In particular, these comments provide data supporting EPA's acknowledgement that the NET Power Cycle should be available over the compliance period and in keeping with the target dates EPA set forth for meeting the emission reductions targets on the schedule proposed for new baseload gas-fired power plants in 2032 and 2035.

Our comments are organized into four sections:

- Section I provides an overview of NET Power, including a description of NET Power's mission, its approach to avoiding greenhouse gas ("GHG") emissions as well as the prevention or avoidance of criteria pollutants.[3]

- In Section II, we provide a detailed description and status of the overall technology and each of the components.

- Section III offers evidence to support NET Power's capabilities and availability per the timeline and emission reduction targets proposed by EPA for new baseload gas-fired power generating units.

- Finally, Section IV encourages EPA to identify the NET Power Cycle as a likely available compliance option for new sources covered by the proposed regulations, suggests the Agency provide clear metrics assessing the NET Power Cycle's qualification as a compliance pathway, and, given the importance of the NET Power cycle as an economic and environmentally protective compliance pathway, incorporate the NET Power Cycle in government planning scenarios assessing emissions reduction in the power sector. This includes EPA's analyses using the Integrated Planning Model. EPA should coordinate with other government agencies' modeling efforts to ensure uniformity and a consistent approach.

I. NET Power Overview

NET Power is a clean energy technology company commercializing a unique and practical solution to produce dispatchable baseload electricity from natural gas through an efficient power generation process that avoids the release of CO_2. NET Power's technology meets net emissions neutrality via a patented oxy-combustion process known as the "NET Power Cycle" – the commercial application of the natural gas-fired Allam Cycle.[4] NET Power believes the NET Power Cycle can help the United States meet increasing societal energy demands, satisfy

[3] There are six criteria air pollutants: ground-level ozone, particulate matter, carbon monoxide, lead, sulfur dioxide, and nitrogen dioxide. EPA, *Criteria Air Pollutants*, https://www.epa.gov/criteria-air-pollutants (last visited Aug. 8, 2023).

[4] *See* Rodney Allam et al., *Demonstration of the Allam Cycle: An Update on the Development Status of a High Efficiency Supercritical Carbon Dioxide Power Process Employing Full Carbon Capture*, 114 Energy Procedia 5948 (2017).

dispatchability and reliability requirements, and achieve GHG emission reduction goals – all at reasonable costs and without sacrificing energy security.

NET Power's power generation solution was developed recognizing the need to use the United States' plentiful natural gas resources in a climate responsible way. NET Power's patented technology uses natural gas to produce low-cost, dispatchable power while avoiding the release of CO_2.[5]

The NET Power Cycle produces power and avoids emissions by combining oxy combustion with a CO_2 power cycle. In the NET Power Cycle, high purity oxygen is combusted with natural gas in a stream of supercritical CO_2. Oxy combustion produces CO_2 and water. The water can be easily separated and removed, leaving supercritical CO_2 to recirculate and drive the power cycle. To maintain system pressure, CO_2 is continuously drawn off the cycle for carbon management activities such as CO_2 utilization or sequestration.[6]

NET Power is commercializing its technology following more than a decade of research, development, and operational demonstration. Over the course of several key investments, construction and testing campaigns were conducted at NET Power's 50MWth Demonstration facility in La Porte, Texas. Recently NET Power announced a slate of strategic engagements, as well as its first commercial-scale 300MWe-class facility. NET Power is steadily driving its technology from concept to full-scale commercialization.

Other recent announcements have further positioned the company for success. In February of 2022, NET Power formed a joint development agreement with Baker Hughes to advance the design of key turbomachinery and equipment used in the NET Power Cycle. In December of 2022 NET Power announced and on June 8, 2023, closed its initial public offering on NYSE (NYSE: NPWR). The transaction provided gross proceeds of upwards of $670M USD to support and fund NET Power through commercialization. As part of the transaction, Danny Rice, former CEO of Rice Energy and an accomplished energy entrepreneur, joined NET Power as CEO, providing his vision and experience to the company at this critical growth phase.

NET Power's progress has been underpinned by the tireless work NET Power and its partners have undertaken to demonstrate the NET Power Cycle at a suitable scale. NET Power had previously raised over $200 million to design, build, and operate its one-of-a-kind demonstration facility in La Porte, Texas, while further progressing the design of commercial products. The demonstration facility, commissioned in 2018, covers five acres and has over 1,500 operational hours as of August 2023.

From its inception, NET Power sought to create a clean natural gas power generation solution that could economically compete against emitting alternatives. The NET Power Cycle was developed before the establishment of incentives for driving carbon capture and sequestration

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[5] *See* NET Power, *Technology*, https://netpower.com/technology (last visited Aug. 5, 2023).

[6] Carbon dioxide utilization is the process of using captured CO_2 "in industrial processes or as feedstock for useful commercial products," while CO_2 sequestration is the process of injecting captured CO_2 underground for long-term storage. Carbon Capture, Utilization, and Sequestration Guidance, 87 Fed. Reg. 8808, 8809 (Feb. 16, 2022).

("CCS") as an emission control solution.[7] In the absence of strong policy incentives, NET Power recognized that GHG emissions control from natural gas power generation required redesigning the combustion cycle from the ground up. Doing so allows the NET Power Cycle to achieve thermal efficiencies on par with average gas-fired power plants while avoiding CO_2 emissions, among other benefits.

In the proposed rules EPA also recognized the expected advantages of the NET Power Cycle, including:

- Unlike other natural gas- or hydrogen-fired generating units, the NET Power Cycle avoids emissions of criteria pollutants, including emissions of nitrogen oxides ("NO_X"), in addition to avoiding CO_2 emissions.

- The NET Power Cycle generates a stream of high-pressure and high-purity CO_2, thereby negating the need for extensive pre-processing of the CO_2 before transmission and storage.

- The NET Power Cycle can inherently capture CO_2 at high capture rates and can do so across the NET Power Cycle's operational profile, from full load power to net zero power to the grid.

These capabilities constitute further important and distinguishing advantages of the NET Power Cycle over alternatives.

It is expected that the NET Power Cycle will play a significant role in reducing emissions from the electric power system by providing reliable, dispatchable, and clean baseload power generation. NET Power plans to initially commercialize and license 300MWe-class versions of the NET Power Cycle, suitable for utility-scale power generation. Using this product, the NET Power Cycle can be broadly deployed as an effective system of emission reduction for compliance with an aggressive emissions performance standard. Because of these capabilities and as discussed in greater detail below, we encourage EPA to include the NET Power Cycle in the modeling tools and processes on which it bases the determination of emission reductions targets as an alternative compliance pathway, which we discuss further in Section IV.

II. Components and Advantages of the NET Power Cycle

A. Description of the NET Power Cycle

The NET Power Cycle is described in steps 1 through 7 in Figure 1, below. Each step includes associated components. These include (1) the air separation unit which separates the oxygen from the air, (2) the combustor where natural gas and oxygen are combined to produce CO_2 and water vapor, (3) the turboexpander which is turned by expanding the CO_2 mixture to generate electricity, (4) the heat exchanger where the CO_2 mixture is routed for cooling, (5) the water separator which removes water from the CO_2 stream, (6) the compression and pumping steps which pressurize the clean, captured CO_2 delivered by the water separator and pumps CO_2 back to the cycle and as well as captured CO_2 to the pipeline for sequestration. The recirculated CO_2 is then (7) reheated to be sent to the combustor and the closed loop cycle begins again.

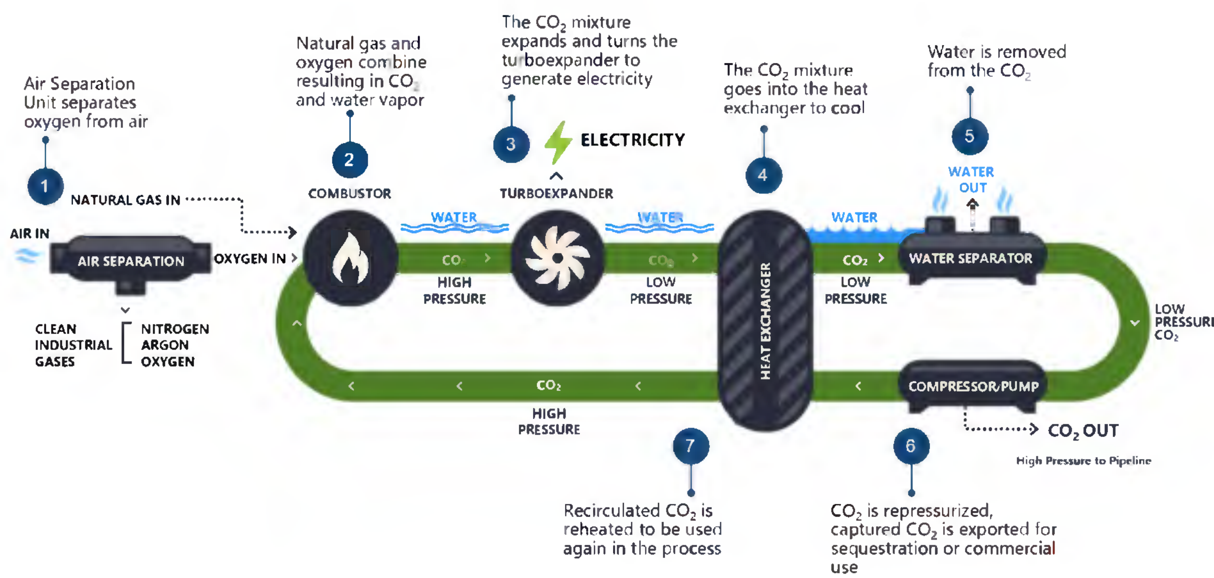

Figure 1: Stepwise Diagram of the NET Power Cycle and Associated Components.

Dispatchability and flexibility lie at the core of NET Power's technology and commercialization strategy. NET Power plants can run on a range of natural gas fuel types, including those blended with hydrogen, and can be configured to produce more water than they consume. NET Power's 300MWe-class plant can be dispatched as both a baseload and load-peaking plant. Moreover, with 8,000 gigatons of potential carbon sequestration capacity in 36 basins across the country, the U.S offers substantial carbon sequestration capacity to support the sequestration of CO_2 at the levels of CO_2 that the NET Power system can capture.

Technical viability and reliability are also key. While novel in its approach, the majority of the components of the NET Power Cycle are either commercially available or have been previously demonstrated. Of the seven steps depicted in Figure 1, above, five of the steps utilize broadly demonstrated and commercially available products. Specifically, air separation units, heat exchangers, water scrubbers/separators, compressors, and pumps are all broadly available.

Step (2), the oxy combustor, and step (3), the turboexpander (together, the NET Power oxy combustor turboexpander ("OCT")), of the NET Power Cycle require the deployment of new equipment. This new equipment is advancing in partnership with shareholder and turbomachinery expert Baker Hughes and will be delivered commercially as a single unit. The OCT utilizes engineered approaches that have already been well demonstrated but must be proven over time and at sufficient scale to function in the high heat and pressure environment of the NET Power plant. Prototypes of these sub-components have been tested at NET Power's La Porte demonstration facility, with a commercial-scale prototype oxy combustor operating for nearly 900 hours. A prototype turboexpander has operated in cold-flow and fired-operation at the test facility for over 1500 hours as of August 2023. The prototype OCT was synchronized to the ERCOT grid in fall of 2021.

NET Power and Baker Hughes formed a strategic partnership in February 2022. Working closely with NET Power, Baker Hughes will move the OCT from prototype to commercial delivery while supporting the technical and commercial deployment of the entire NET Power Cycle. Through the joint development agreement, Baker Hughes has invested cash equity into NET Power while contributing its advanced technology capabilities to deploy the OCT and provide other key process equipment for NET Power facilities. The structure of the partnership facilitates the sharing of best practices and lessons learned, while also aligning commercial efforts globally through joint marketing of the technology. By the proposed regulatory deadlines of 2032 and 2035, Baker Hughes and NET Power expect to have scaled production of key components and widely deployed the NET Power Cycle.

B. Advantages of the NET Power Cycle

The NET Power Cycle can address the gaps that currently exist in planning and creating the clean grid of the future. By employing the NET Power Cycle and its unique benefits, we expect to meet growing energy demands, satisfy dispatchability and reliability requirements, and achieve GHG emission reduction goals – all at reasonable costs and without sacrificing energy security. These benefits include[8]:

Clean: the NET Power Cycle deployed at scale can deliver greater emissions reductions, avoiding emissions of both CO_2 and criteria pollutants;

Affordable: NET Power can provide necessary emissions control and power generation at reasonable costs; and

Reliable and Flexible: NET Power expects its facilities to provide dispatchable baseload power, firming the energy supply, while offering greenfield and brownfield siting flexibility.

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[8] Form S-4 for Rice Acquisition Corp. II as filed with the Securities and Exchange Commission at 203 (May 8, 2023), available at https://www.sec.gov/ix?doc=/Archives/edgar/data/0001845437/000121390023037428/fs42023a5_riceacqcorp2.htm#T15.

Clean: Regarding the delivery of higher emissions reductions, the NET Power Cycle delivers power generation on a life cycle assessment basis that is 70 percent cleaner than post-combustion carbon capture from traditional natural gas power generation plants[9]. NET Power estimates emission reductions of up to 66% (~ 2 gigatons per year) if NET Power plants were to replace all coal and gas plants in the United States.

Affordable: With respect to the economics of the NET Power Cycle, NET Power has been designed to be cost competitive when compared to conventional, emitting baseload natural gas power generation options. This begins with the configuration of the cycle, which captures CO_2 as a design requirement of the underlying power production process while still optimizing the facility design for power generation. This, coupled with the financial incentives provided by the Inflation Reduction Act of 2022 which provide a tax credit of $85/tonne for geological carbon sequestration and $60/tonne for CO_2 used for enhanced oil recovery and other processes which apply to the CO_2 captured by the NET Power System, make the NET Power technology economical as compared to power generation alternatives.

Reliable and Flexible: Regarding NET Power's superior CO_2 capture and criteria emissions capture capability, the NET Power Cycle requires no additional resources (i.e., does not require power to be diverted or added to the system to operate carbon capture equipment) to employ emissions capture. This not only protects against the emission of CO_2 since NET Power does not need to rely on separate post-combustion carbon capture equipment to capture CO_2 emissions, but it ensures that emissions are captured continuously across a NET Power facility's operational profile (from 0% to 100% load) at NET Power's high CO_2 capture rates and that the CO_2 stream is in a form that is immediately ready for delivery to a CO_2 pipeline, making it much easier to transport the captured CO_2. Meanwhile, because NET Power Cycle facilities inherently capture criteria pollutants, siting and permitting flexibility is also improved.

NET Power's footprint is smaller than peer technologies such as combined cycle with post combustion carbon capture. This is possible because of the high pressures at which the NET Power cycle operates, resulting in a physical plant footprint 50% smaller than traditional coal, and smaller than a similarly sized natural gas combined cycle facility with carbon capture. NET Power's ability to fit into a smaller footprint means that it is much more feasible to select NET Power plants as repowering options at retiring plant sites versus new-build post-combustion carbon capture projects. Multiple NET Power facilities can also be arranged on new or existing sites to provide larger power generation capacity.

Finally, because NET Power's mission-oriented approach centers on the large-scale reduction of GHGs from fossil fuel use, NET Power plans to undertake a business approach focused on the speedy deployment of NET Power plants. NET Power plans to license the technology to accelerate the adoption of the NET Power Cycle as broadly as possible. NET Power will also establish and deploy a "standard plant" to accelerate cost reductions through standardization and modularization and allowing for ongoing improvement of the comprehensive NET Power Cycle and NET Power product package.

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[9] NET Power PIPE Presentation at 19 (December 2022), available at https://ir.netpower.com/resources/presentations.

III. Readiness of the NET Power Cycle

EPA's proposal correctly noted that many of the demonstrated turbine technologies require some "lead time" which is "the time in which the technology will have to be available."[10] This observation also applies to NET Power.

While the NET Power Cycle has been operated at demonstration scale, NET Power's commercial plant will validate and deploy the technology at the 300MWe-class commercial scale. NET Power has begun its Front-End Engineering and Design ("FEED") study for this plant, expects to complete the FEED study in 2024, and is targeting to complete construction in 2026. Following completion of construction, NET Power will operate and validate the 300MWe-class commercial product.

NET Power is focused on delivering a project that will quickly catalyze future adoption for utility-scale customers. After the anticipated operation of the first commercial plant, NET Power intends to widely offer and deliver its plants to the market in keeping with the timing of the EPA proposal. By the 2035 date by which baseload plants would need to demonstrate 90 percent carbon capture at units constructed today, NET Power would be fully available to meet those reduction levels.

NET Power's projected market availability is corroborated by recent modeling runs produced by DeSolve, a consulting firm led by Dr. Jesse Jenkins, an associate professor at Princeton University who leads Princeton's Zero-Carbon Energy Systems Research and Optimization Laboratory. The DeSolve analysis, which was recently filed with the SEC and is attached as Appendix A to our comments, found that:

1. The potential deployment of the NET Power cycle technology could achieve capacity buildout of ~15 GW by 2030 and ~580 GW by 2050 under targeted cost and performance.

2. In the medium-term, the limiting constraint for the deployment of the NET Power cycle will be the scaling of the supply-chain and the project development capacity, not project economics since the modeling hits the maximum deployment bounds every year until 2030.

3. By 2050, the NET Power Cycle technology could contribute ~25% of U.S. total electricity generation, playing a crucial role in complementing and firming variable renewables.

In addition, the long and established record of NET Power's shareholders provides further assurance that the technology will scale quickly enough to be available for the latter stages of EPA's proposed standard. NET Power has multiple notable strategic shareholders, including Rice Investment Group (which has consistently scaled energy products in the natural gas supply

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[10] Proposed Rule at 33272.

chain), Baker Hughes (which brings engineered equipment and CO_2 management experience), Constellation Energy Group (which brings operational and power generation expertise), Occidental Petroleum (which brings expertise in CO_2 management), and SK Group (which constitutes a collection of global companies driving innovations in sustainable energy). Together, these partners each have a proven track record in the power sector, including the construction and implementation of facilities and technologies of similar scale and complexity to the NET Power Cycle's 300MWe-class deployment.

NET Power is well capitalized, something the Agency should consider as it evaluates the availability of the NET Power Cycle as a compliance option during the timeframe of the proposed regulation. On top of NET Power's prior investments of over $200 million, NET Power recently completed a public offering which garnered a further $670 million in gross proceeds to support NET Power through commercialization. NET Power's combination of sophisticated partnerships and new financing sources will make it possible to achieve NET Power's broad deployment vision.

In addition to the capital already raised, NET Power's public offering ensures ongoing access to the scale of financing required to ensure broad adoption of the NET Power Cycle. NET Power's new public status further cements NET Power's commitment to our shareholders to deliver on this vision. Perhaps most importantly, NET Power believes that our technology should be shared with the world, open to the feedback, discourse, and opportunity that can only be achieved by subjecting the firm to the scrutiny of the public eye.

IV. Recommendations for EPA

Given the expectations for commercialization of the NET Power Cycle described above, NET Power requests that EPA do the following:

(1) Explicitly consider the NET Power Cycle as a means of complying with the final regulation and indicate the NET Power Cycle as a likely compliance option for new natural gas-fired EGUs covered by the proposed regulations.

(2) EPA should create clear metrics by which to assess the NET Power Cycle's qualification as a compliance pathway. EPA should provide these metrics to state and federal regulators to help assure that the NET Power technology satisfies the standards in the final regulation for new natural gas-fired EGUs.

(3) Given the importance of the NET Power Cycle as an economic and environmentally protective compliance pathway for new gas-fired turbines, NET Power also requests that EPA incorporate it in government planning scenarios assessing emissions reduction in the power sector. This includes EPA's analyses using the Integrated Planning Model ("IPM"), used by the EPA to evaluate the impacts of the regulation. NET Power is prepared to provide the data and cost projections necessary for incorporation into the IPM or other relevant models.

(4) EPA should ensure consistency by engaging with other federal agencies also conducting such analyses, such as the Department of Energy and DOE-affiliated national laboratories, the Energy Information Administration, and the Tennessee Valley Authority, to encourage a consistent governmental approach to future planning inclusive of the NET Power Cycle.

NET Power is ready and willing to support the EPA in implementing these recommendations.

V. Conclusion

The NET Power Cycle is projected to be commercially available at sufficient CO_2 capture rate performance (>90% as required by the proposed rules), suitable scale (300MWe-class), and able to be deployed widely in time (i.e., by 2032-2035) to meet the performance standards proposed by EPA. While NET Power's technology is not yet widely available, EPA observed that carbon capture technologies require some lead time prior to widespread deployment and must be supported by infrastructure in a manner that would allow them to be the basis of an emissions standard. NET Power agrees with EPA's conclusion. However, NET Power projects that the lead time provided by EPA will be sufficient to allow NET Power's technology to mature so that it would be available as a means of compliance for the proposed rule.

In sum, NET Power recommends that EPA observe its projected availability as a compliant approach to these regulations with the added benefits of complete reductions in other criteria pollutants, the provision of reliable baseload power to support intermittent renewables, and minimal land usage with the plant's small footprint.

Should you have any questions regarding these comments, please contact Scott Martin, Chief Technology Officer, at Scott.Martin@netpower.com or by telephone at 303-912-4355.

Sincerely,

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