ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2023–0072; FRL–8536–02–OAR]

RIN 2060–AV09

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this document, the Environmental Protection Agency (EPA) is proposing five separate actions under section 111 of the Clean Air Act (CAA) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs). 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.

DATES: *Comments.* Comments must be received on or before July 24, 2023. Comments on the information collection provisions submitted to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA) are best assured of consideration by OMB if OMB receives a copy of your comments on or before June 22, 2023.

Public Hearing. The EPA will hold a virtual public hearing on June 13, 2023 and June 14, 2023. See **SUPPLEMENTARY INFORMATION** for information on registering for a public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2023–0072, by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2023–0072 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2023–0072.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2023–0072, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For questions about these proposed actions, contact Mr. Christian Fellner, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–4003; and email address: *fellner.christian@epa.gov* or Ms. Lisa Thompson, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–9775; and email address: *thompson.lisa@epa.gov.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. The public hearing will be held via virtual platform on June 13, 2023 and June 14, 2023 and will convene at 11:00 a.m. Eastern Time (ET) and conclude at 7:00 p.m. ET each day. If the EPA receives a high volume of registrations for the public hearing, the EPA may continue the public hearing on June 15, 2023. On each hearing day, the EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

The EPA will begin pre-registering speakers for the hearing no later than 1 business day following the publication of this document in the **Federal Register**. The EPA will accept registrations on an individual basis. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power* or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* The last day to pre-register to speak at the hearing will be June 6, 2023. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony by submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.* While the EPA expects the hearing to go forward as described in this section, please monitor our website or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of an interpreter or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by May 30, 2023. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for these rulemakings under Docket ID No. EPA–HQ–OAR–2023–0072. All documents in the docket are listed in the *Regulations.gov* index. Although listed in the index, 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.

Written Comments. Direct your comments to Docket ID No. EPA–HQ–OAR–2023–0072 at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

Multimedia submissions (audio, video, *etc.*) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI or multimedia submissions; and general guidance on making effective comments.

The *https://www.regulations.gov* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and should be free of any defects or viruses.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Written Comments* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). 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 note the docket ID. 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. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2023–0072. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

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
BACT best available control technology
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
CFR Code of Federal Regulations
CHP combined heat and power
CO_2 carbon dioxide
CO2e carbon dioxide equivalent
CPP Clean Power Plan
CSAPR Cross-State Air Pollution Rule
DOE Department of Energy
DOI Department of the Interior
DOT Department of Transportation
EGU electric generating unit
EIA Energy Information Administration
EJ environmental justice
E.O. Executive Order
EOR enhanced oil recovery
EPA Environmental Protection Agency
FEED front-end engineering and design
FGD flue gas desulfurization
FR Federal Register
FrEDI Framework for Evaluating Damages and Impacts
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GW gigawatt
HHV higher heating value
HRSG heat recovery steam generator
IBR incorporate by reference
ICR information collection request
IGCC integrated gasification combined cycle
IIJA Infrastructure Investment and Jobs Act
IPCC Intergovernmental Panel on Climate Change
IRC Internal Revenue Code
IRP integrated resource plan
kg kilogram
kWh kilowatt-hour
LCOE levelized cost of electricity
LHV lower heating value
LNG liquefied natural gas
MMBtu/hr million British thermal units per hour
MMst million short tons
MMT CO_2e million metric tons of carbon dioxide equivalent
MW megawatt
MWh megawatt-hour

NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NCA4 2017–2018 Fourth National Climate Assessment
NETL National Energy Technology Laboratory
NGCC natural gas combined cycle
NO_X nitrogen oxides
NREL National Renewable Energy Laboratory
NSPS new source performance standards
NSR New Source Review
OMB Office of Management and Budget
PM particulate matter
PSD Prevention of Significant Deterioration
PUC public utilities commission
RIA regulatory impact analysis
RPS renewable portfolio standard
RTO Regional Transmission Organization
SCR selective catalytic reduction
SIP State Implementation Plan
U.S. United States
U.S.C. United States Code

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

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. 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 2020. 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—including carbon capture and sequestration/storage (CCS) and co-firing with lower-GHG fuels. Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to

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

achieve reductions in GHG emissions from the power sector.

In this document, the EPA is proposing several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from new and existing fossil fuel-fired EGUs by establishing new source performance standards (NSPS) and emission guidelines that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of section 111, the proposed 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 proposing to update and establish more protective NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs that are based on highly efficient generating practices, hydrogen co-firing, and CCS. The EPA is also proposing to establish new emission guidelines for existing fossil fuel-fired steam generating EGUs that reflect the application of CCS and the availability of natural gas co-firing. The EPA is simultaneously proposing to repeal the Affordable Clean Energy (ACE) rule because the emission guidelines established in ACE do not reflect the BSER for steam generating EGUs and are inconsistent with section 111 of the CAA in other respects. To address GHG emissions from existing fossil fuel-fired stationary combustion turbines, the EPA is proposing emission guidelines for large and frequently used existing stationary combustion turbines. Further, the EPA is soliciting comment on how the Agency should approach its legal obligation to establish emission guidelines for the remaining existing fossil fuel-fired combustion turbines not covered by this proposal, including smaller frequently used, and less frequently used, combustion turbines.

Each of the NSPS and emission guidelines proposed here would ensure that EGUs 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 proposed standards and emission guidelines, if finalized, would significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA has designed these proposed standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

A. Climate Change and the Power Sector

These proposals focus on reducing the emissions of GHGs from the power sector. 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 threatens human welfare.

The power sector in the United States (U.S.) is both a key contributor to the cause of climate change and a key component of the solution to the climate challenge. In 2020, the power sector was the largest stationary source of GHGs, emitting 25 percent of the overall domestic emissions.[2] These emissions are almost entirely the result of the combustion of fossil fuels in the EGUs that are the subjects of these proposals.

The power sector possesses many opportunities to contribute to solutions to the climate challenge. Particularly relevant to these proposals are several key technologies (co-firing of low-GHG fuels and CCS) that can allow steam generating EGUs and stationary combustion turbines (the focus of these proposals) 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, a power sector with lower GHG emissions can also help reduce pollution coming from other sectors of the economy.

B. Overview of the Proposals

As noted above, these actions include proposed BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines, proposed repeal of the ACE Rule, proposed BSER determinations and emission guidelines for existing fossil fuel-fired steam generating units, proposed BSER determinations and emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines, and solicitation for comment on potential BSER options and emission guidelines for existing fossil fuel-fired stationary combustion turbines not otherwise covered by the proposal.

The EPA is taking these actions consistent with the process that CAA section 111 establishes. Under CAA section 111, once the EPA has identified a source category that emits dangerous air pollutants, 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. CAA section 111(a)(1). The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER and may subcategorize sources accordingly.

Once it determines the BSER, the EPA must determine the ''degree of emission limitation'' achievable by application of the BSER. For new sources, the EPA determines 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 into 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 section 111 for more than 60 source categories, which has established a robust regulatory history. 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 section 111. As the Supreme Court has recognized, in these CAA section 111 actions, the EPA has determined the BSER to be ''measures that improve the pollution performance of individual sources,'' including add-on controls and clean fuels. *West Virginia* v. *EPA,* 142 S. Ct. 2587, 2614 (2022). For present purposes, several of a BSER's key features include that costs of controls must be reasonable, that 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. The actions that the EPA is proposing are consistent with the requirements of CAA section 111 and its regulatory history and caselaw.

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

1. New and Reconstructed Fossil Fuel-Fired Combustion Turbines

For new and reconstructed fossil fuel-fired combustion turbines, the EPA is proposing to create three subcategories based on the function the combustion turbine serves: a low load (''peaking units'') subcategory that consists of combustion turbines with a capacity factor of less than 20 percent; an intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine; and a base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines. This subcategorization approach is similar to the current NSPS for these sources, which includes separate subcategories for base load and non-base load units; however, the EPA is now proposing to subdivide the non-base load subcategory into a low load subcategory and a separate intermediate load subcategory. This revised approach to subcategories is consistent with the fact that utilities and power plant operators are building new combustion turbines with plans to operate them at varying levels of capacity, in coordination with existing and expected energy sources. These patterns of operation are important for the type of controls that the EPA is proposing as the BSER for these turbines, in terms of the feasibility of, emissions reductions that would be achieved by, and cost-reasonableness of, those controls.

For the low load subcategory, the EPA is proposing that the BSER is the use of lower emitting fuels (*e.g.,* natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted.[3] For the intermediate load and base load subcategories, the EPA is proposing an approach in which the BSER has multiple components: (1) Highly efficient generation; and (2) depending on the subcategory, use of CCS or co-firing low-GHG hydrogen.

These components of the BSER for the intermediate and base load subcategories form the basis of a standard of performance that applies in multiple phases. That is, affected facilities—which are facilities that commence construction or reconstruction after the date of publication in the **Federal Register** of this proposed rulemaking—must meet the first phase of the standard of performance, which is based exclusively on application of the first component of the BSER (highly efficient generation), by the date the rule is promulgated. Affected sources in the intermediate load and base load subcategories must also meet the second and in some cases third and more stringent phases of the standard of performance, which are based on the continued application of the first component of the BSER and the application of the second and in some cases third component of the BSER. For base load units, the EPA is proposing two pathways as potential BSER—(1) the use of CCS to achieve a 90 percent capture of GHG emissions by 2035 and (2) the co-firing of 30 percent (by volume) low-GHG hydrogen by 2032, and ramping up to 96 percent by volume low-GHG hydrogen by 2038. These two BSER pathways both offer significant opportunities to reduce GHG emissions but, may be available on slightly different timescales. Depending upon the phase in periods for both CCS and hydrogen, the CCS pathway could provide greater cumulative emission reductions than the low GHG hydrogen pathway. The EPA seeks comment specifically upon the percentages of hydrogen co-firing and CO_2 capture as well as the dates that meet the statutory BSER criteria for each pathway. The EPA solicits comment on the differences in emissions reductions in both scale and time that would result from the two standards and BSER pathways, including how to calculate the different amounts of emission reductions, how to compare them, and what conclusions to draw from those differences. The EPA also seeks comment on whether the Agency should finalize both pathways as separate subcategories with separate standards of performance, or whether it should finalize one pathway with the option of meeting the standard of performance using either system of emission reduction, *e.g.,* a single standard based on application of CCS with 90 percent capture, which could also be met by co-firing 96 percent (by volume) low-GHG hydrogen.

It should be noted that utilization of highly efficient generation is a logical complement to both CCS and co-firing of low-GHG hydrogen because, from both an economic and emissions perspective, that configuration will provide the greatest reductions at the lowest cost. This approach reflects the EPA's view that the BSER for the intermediate load and base load subcategories should reflect the deeper reductions in GHG emissions that can be achieved by implementing CCS and co-firing low-GHG hydrogen with the most efficient stationary combustion turbine configuration available. However, in proposing that compliance begins in 2032 (for co-firing with low-GHG hydrogen) and 2035 (for use of CCS), the EPA recognizes that building the infrastructure required to support wider use of CCS and qualified low-GHG hydrogen in the power sector will take place on a multi-year time scale.

More specifically, with respect to the first phase of the standards of performance, the EPA is proposing that the BSER for both the intermediate load and base load subcategories includes highly efficient generating technology (*i.e.,* the most efficient available turbines). For the intermediate load subcategory, the EPA is proposing that the BSER includes highly efficient simple cycle combustion turbine technology with an associated first phase standard of 1,150 lb CO_2/MWh-gross. For the base load subcategory, the EPA is proposing that the BSER includes highly efficient combined cycle technology with an associated first phase standard of 770 lb CO_2/MWh-gross for larger combustion turbine EGUs with a base load rating of 2,000 MMBtu/h or more. For smaller base load combustion turbines (with a base load rating of less than 2,000 MMBtu/h), the proposed associated standard would range from 770 to 900 lb CO_2/MWh-gross depending on the specific base load rating of the combustion turbine. These standards would apply immediately upon the effective date of the final rule.

With respect to the second phase of the standards of performance, for the intermediate load subcategory, the EPA is proposing that the BSER includes co-firing 30 percent by volume low-GHG hydrogen (unless otherwise noted, all co-firing hydrogen percentages are on a volume basis) with an associated standard of 1,000 lb CO_2/MWh-gross, compliance with which would be required starting in 2032. For the base load subcategory, to elicit comment on both pathways, the EPA is proposing to subcategorize further into base load units that are adopting the CCS pathway and base load units that are adopting the low-GHG hydrogen co-firing pathway. For the subcategory of base load units that are adopting the CCS pathway, the EPA is proposing that the BSER includes the use of CCS with 90 percent capture of CO_2 with an associated standard of 90 lb CO_2/MWh-gross, compliance with which would be

[3] In the 2015 NSPS, the EPA referred to clean fuels as 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). Fuels in this category include natural gas and distillate oil. In this rulemaking, the EPA refers to these fuels as both lower emitting fuels or uniform fuels.

required starting in 2035. For the subcategory of base load units that are adopting the low-GHG hydrogen co-firing pathway, the EPA is proposing that the BSER includes co-firing 30 percent (by volume) low-GHG hydrogen with an associated standard of 680 lb CO_2/MWh-gross, compliance with which would be required starting in 2032, and co-firing 96 percent (by volume) low-GHG hydrogen by 2038, which corresponds to a standard of performance of 90 lb CO_2/MWh-gross. In both cases, the second (and sometimes third) phase standard of performance would be applicable to all combustion turbines that were subject to the first phase standards of performance.

Existing and Modified Fossil Fuel-Fired Steam Generating Units and ACE Repeal

With respect to existing coal-fired steam generating units, the EPA is proposing to repeal and replace the existing ACE Rule emission guidelines. 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); and the costs of natural gas co-firing have decreased as well, due in large part to a decrease in the difference between coal and natural gas prices. As a result, the EPA considered both CCS and natural gas co-firing as candidates for BSER for existing coal-fired steam EGUs.

Based on the latest information available to the Agency on cost, emission reductions, and other statutory criteria, the EPA is proposing that the BSER for existing coal-fired steam EGUs that expect to operate in the long-term is CCS with 90 percent capture of CO_2. The EPA has determined that CCS satisfies the BSER criteria for these sources because it is adequately demonstrated, achieves significant reductions in GHG emissions, and is highly cost-effective.

Although the EPA considers CCS to be a broadly applicable BSER, the Agency also recognizes that CCS will be most cost-effective for existing steam EGUs that are in a position to recover the capital costs associated with CCS over a sufficiently long period of time. During the early engagement process (see Docket ID No. EPA–HQ–OAR–2022–0723–0024), 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 (see Docket ID No. EPA–HQ–OAR–2022–0723–0029).

In response to this industry stakeholder input and recognizing that the cost effectiveness of controls depends on the unit's expected operating time horizon, which dictates the amortization period for the capital costs of the controls, the EPA believes it is appropriate to establish subcategories of existing steam EGUs that are based on the operating horizon of the units. The EPA is proposing that for units that expect to operate in the long-term (*i.e.,* those that plan to operate past December 31, 2039), the BSER is the use of CCS with 90 percent capture of CO_2 with an associated degree of emission limitation of an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis). As explained in detail in this proposal, CCS with 90 percent capture of CO_2 is adequately demonstrated, cost reasonable, and achieves substantial emissions reductions from these units.

The EPA is proposing to define coal-fired steam generating units with medium-term operating horizons as those that (1) Operate after December 31, 2031, (2) have elected to commit to permanently cease operations before January 1, 2040, (3) elect to make that commitment federally enforceable and continuing by including it in the State plan, and (4) do not meet the definition of near-term operating horizon units. For these medium-term operating horizon units, the EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis with an associated degree of emission limitation of a 16 percent reduction in emission rate (lb CO_2/MWh-gross basis). While this subcategory is based on a 10-year operating horizon (*i.e.,* January 1, 2040), the EPA is specifically soliciting comment on the potential for a different operating horizon between 8 and 10 years to define the threshold date between the definition of medium-term and long-term coal-fired steam generating units (*i.e.,* January 1, 2038 to January 1, 2040), given that the costs for CCS may be reasonable for units with amortization periods as short as 8 years. For units with operating horizons that are imminent-term, *i.e.,* those that (1) Have elected to commit to permanently cease operations before January 1, 2032, and (2) elect to make that commitment federally enforceable and continuing by including it in the State plan, the EPA is proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross basis). The EPA is proposing the same BSER determination for units in the near-term operating horizon subcategory, *i.e.,* units that (1) Have elected to commit to permanently cease operations by December 31, 2034, as well as to adopt an annual capacity factor limit of 20 percent, and (2) elect to make both of these conditions federally enforceable by including them in the State plan. The EPA is also soliciting comment on a potential BSER based on low levels of natural gas co-firing for units in these last two subcategories.

The EPA is not proposing to revise the NSPS for newly constructed or reconstructed fossil fuel-fired steam generating units, which it promulgated in 2015 (80 FR 64510; October 23, 2015). This is because the EPA does not anticipate that any such units will construct or reconstruct and is unaware of plans by any companies to construct or reconstruct a new coal-fired EGU. The EPA is proposing to revise the standards of performance that it promulgated in the same 2015 action for coal-fired steam generators that undertake a large modification (*i.e.,* a modification that increases its hourly emission rate by more than 10 percent) to mirror the emissions guidelines, discussed below, for existing coal-fired steam generators. This will ensure that all existing fossil fuel-fired steam generating sources are subject to the emission controls whether they modify or not.

The EPA is also proposing emission guidelines for existing natural gas-fired and oil-fired steam generating units. Recognizing that virtually all of these units have limited operation, the EPA is, in general, proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross).

3. Existing Fossil Fuel-Fired Stationary Combustion Turbines

The EPA is also proposing emission guidelines for large (*i.e.,* greater than 300 MW), frequently operated (*i.e.,* with a capacity factor of greater than 50 percent), existing fossil fuel-fired stationary combustion turbines. Because these existing combustion turbines are similar to new stationary combustion turbines, the EPA is proposing a BSER that is similar to the BSER for new base load combustion turbines. The EPA is not proposing a first phase efficiency-based standard of performance; but the EPA is proposing that BSER for these units is based on either the use of CCS by 2035 or co-firing of 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent low-GHG hydrogen by 2038.

For the emission guidelines for existing fossil fuel-fired steam generating units and large, frequently operated fossil fuel-fired combustion turbines, the EPA is also proposing State plan requirements, including submittal timelines for State plans and methodologies for determining presumptively approvable standards of performance consistent with BSER. This proposal also addresses how states can implement the remaining useful life and other factors (RULOF) provision of CAA section 111(d) and how states can conduct meaningful engagement with impacted stakeholders. Finally, the EPA is proposing to allow states to include trading or averaging in State plans so long as they demonstrate equivalent emissions reductions, and this proposal discusses considerations related to the appropriateness of including such compliance flexibilities.

Finally, the EPA is soliciting comment on a number of variations to the subcategories and BSER determinations, as well as the associated degrees of emission limitation and standards of performance, summarized above. The EPA is soliciting comment on the capacity and capacity factor threshold for inclusion in the subcategory of large, frequently operated turbines (*e.g.,* capacities between 100 MW and 300 MW for the capacity threshold and a lower capacity factor threshold (*e.g.,* 40 percent). The EPA is also soliciting comment on BSER options and associated degrees of emission limitation for existing fossil fuel-fired stationary combustion turbines for which no BSER is being proposed (*i.e.,* fossil fuel-fired stationary combustion turbines that are not large, frequently operated turbines).

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

Several recent developments concerning emissions controls and the state of the electric power sector are relevant for the EPA's determination of the BSER for existing coal-fired steam generating EGUs and natural gas-fired combustion turbines. These include developments that have led to significant reductions in the cost of CCS; expected increases in the availability and expected reductions in the cost of low-GHG hydrogen; and announced and planned retirements of coal-fired power plants.

In recent years, the cost of CCS has declined in part because of process improvements learned from earlier deployments of CCS and other advances. In addition, the IRA, enacted in 2022, extended and significantly increased the tax credit for CCS under Internal Revenue Code (IRC) section 45Q. As explained in detail in the BSER discussions later in this preamble, these changes support the EPA's proposed conclusion that CCS is the BSER for a number of subcategories in these proposals.

In addition, in both the Infrastructure Investment and Jobs Act (IIJA), enacted in 2021, and the IRA, Congress provided extensive support for the development of hydrogen produced through low-GHG methods. This support includes investment in infrastructure through the IIJA and the provision of tax credits in the IRA to incentivize the manufacture of hydrogen through low GHG-emitting methods. These changes also support the EPA's proposal that co-firing low-GHG hydrogen is BSER for certain subcategories of stationary combustion turbines.

The IIJA and IRA have also been part of the reason why many utilities and power generating companies have recently announced plans to change the mix of their generating assets. State legislation, technology advancements, market forces, consumer demand, and the fact that the existing fossil fuel-fired fleet is aging are also leading to, in most cases, decreased use of the fossil fuel-fired units that are the subjects of these proposals. Between 2010 and 2021, fossil fuel-fired generation declined from approximately 70 percent of total net generation to approximately 60 percent, with coal generation dropping from 46 percent to 23 percent of net generation during the period.

Many utilities and power generating companies have announced GHG reduction commitments as they further analyze and consider the incentives of the IRA. These utilities and companies have also announced their intention to permanently cease operating many of their remaining coal-fired EGUs. Some companies are planning to install combustion turbines with advanced technologies to limit GHG emissions, including CCS and hydrogen co-firing [4] (with some companies having announced plans to ultimately move to 100 percent hydrogen firing) and advanced energy storage technologies. As more renewables come online and as these technologies become more widely deployed, the utilization of natural gas-fired combustion turbine EGUs will be impacted. The EPA's post-IRA 2022 reference case modeling projects lower utilization relative to current levels of stationary combustion turbines.

The power sector has also been influenced by the actions of State governments to reduce GHG emissions. More than two-thirds of states have enacted policies to require utilities to increase the amount of electricity generated from sources that emit no GHGs. Other states have recently enacted significant legislation requiring the decarbonization of their utility fleets, using devices such as carbon markets, low-GHG emission standards, carbon capture and storage mandates, utility planning, or mandatory retirement schedules.

Additionally, Congress has recently enacted investments in GHG reductions. As noted earlier, Congress enacted IRC section 45Q by section 115 of the Energy Improvement and Extension Act of 2008, to provide a credit for the sequestration of CO_2; IRC section 45Q was amended significantly by the Bipartisan Budget Act of 2018 and most recently by the IRA. The IIJA provided more than $65 billion for infrastructure investments and upgrades for transmission capacity, pipelines, and low-carbon fuels (including low-GHG hydrogen, as noted above). In addition, 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 will provide additional low-cost options for power companies to reduce overall GHG emissions.[5]

Finally, the EPA has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals and is confident that these proposed NSPS and emission guidelines—with the extensive lead time and compliance flexibilities they provide—can be successfully implemented in a manner that preserves the ability of power companies and grid operators to maintain the reliability of the nation's electric power system. The EPA has evaluated the reliability implications of the proposal in the *Resource Adequacy Analysis* TSD; conducted dispatch modeling of the proposed NSPS and

[4] See section VII.F.3.b of this preamble for discussion of CCS demonstrations and section VII.F.3.c for discussion of hydrogen co-firing demonstrations. Also see the *GHG Mitigation Measures for Steam Generating Units* TSD included in the rulemaking docket for this proposal.

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

proposed emission guidelines in a manner that takes into account resource adequacy needs; and consulted with the DOE and the Federal Energy Regulatory Commission (FERC) in the development of these proposals. Moreover, the EPA has included in these proposals the flexibility that power companies and grid operators need to plan for achieving feasible and necessary reductions of GHGs from these sources consistent with the EPA's statutory charge while ensuring grid reliability. Furthermore, the EPA is soliciting comment on localized impacts of these proposals on resource adequacy and reliability, and on opportunities to enhance reliable integration of the proposals into the power system.

D. How the EPA Considered Environmental Justice in the Development of These Proposals

Consistent with E.O. 12898, E.O. 13985 and the EPA's commitment to upholding environmental justice across its policies and programs, the EPA carefully considered the impacts of these proposals on communities with potential environmental justice concerns. As part of its pre-proposal outreach to stakeholders, the EPA engaged on multiple occasions with environmental justice organizations and representatives of communities that are affected by various forms of pollution from the power sector. The EPA took this feedback and analysis into account in its development of these proposals. The EPA's consideration of environmental justice in these proposals is briefly summarized here and discussed in further detail in sections XIV.E and XV.J of the preamble and section 6 of the RIA.

These proposals are focused on establishing NSPS and emission guidelines for GHGs, and these proposed actions will, in conjunction with other policies such as the IRA, play a significant role in reducing GHGs and move us a step closer to avoiding the worst impacts of climate change, which is already having a disproportionate impact on EJ communities. Beyond the GHG reductions, the EPA also has conducted a thorough evaluation of the impacts that these proposals would have on emissions of other health-harming air pollutants from EGUs, as well as how these changes in emissions would affect air quality and public health, particularly for historically overburdened populations including people of color, indigenous peoples, and people with low incomes.

The EPA's national-level analysis of emission reduction and public health impacts, which is documented in sections 3 and 4 of the RIA and summarized in greater detail in section XIV.A and XIV.D of this preamble, finds that these proposals would 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 ($PM_{2.5}$). These reductions in health-harming pollution would result in significant public health benefits including avoided premature deaths, reductions in new asthma cases and incidences of asthma symptoms, reductions in hospital admissions and emergency department visits, and reductions in lost work and school days.

The EPA has also evaluated how the air quality impacts associated with these proposals would be distributed, with particular focus on potentially vulnerable populations. As discussed in section 6 of the RIA, these proposals are anticipated to lead to modest but widespread reductions in ambient levels of $PM_{2.5}$ for a large majority of the nation's population, as well as reductions in ambient $PM_{2.5}$ exposures that are similar in magnitude across all racial, ethnic, income and linguistic groups. Similarly, the EPA found that the proposed standards are anticipated to lead to modest but widespread reductions in ambient levels of ground-level ozone for the majority of the nation's population, and that in all but one of the years evaluated the proposed standards would lead to reductions in ambient ozone exposures across all demographic groups. Although these reductions in $PM_{2.5}$ and ozone exposures are small relative to baseline levels, and although disparities in $PM_{2.5}$ and ozone exposure would continue to persist following these proposals, the EPA's analysis indicates that the air quality benefits of these proposals would be broadly distributed.

Where authorized under section 111 of the Clean Air Act, the EPA has also incorporated provisions in these proposals to better address the needs and concerns of communities with environmental justice concerns. Specifically, the EPA's proposed emission guidelines for existing steam EGUs as well as existing fossil fuel-fired stationary combustion turbines would require states to undertake meaningful engagement with affected stakeholders, including communities that are most affected by and vulnerable to emissions from these EGUs. These meaningful engagement requirements are intended to ensure that the perspectives, priorities, and concerns of affected communities 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.

In the Agency's pre-proposal outreach, some environmental justice organizations and community representatives raised strongly held concerns about the potential health, environmental, and safety impacts of CCS. The EPA believes that deployment of CCS can take place in a manner that is protective of public health, safety, and the environment, and should include early and meaningful engagement with affected communities and the public. As stated in the Council on Environmental Quality's (CEQ) February 2022 Carbon Capture, Utilization, and Sequestration Guidance, ''the successful widespread deployment of responsible CCUS will require strong and effective permitting, efficient regulatory regimes, meaningful public engagement early in the review and deployment process, and measures to safeguard public health and the environment.'' See 87 FR 8808 (February 16, 2022).

The EPA gave close consideration to these concerns as it developed its proposed determinations on the BSER for these proposed NSPS and emission guidelines, and addresses certain of the substantive issues that were raised in pre-proposal discussions in sections VII.F.3.b.iii(C) and X.D.1.a.iii of this preamble. As explained in these sections, the EPA is proposing to determine 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. In evaluating concerns raised by stakeholders in connection with CCS, the EPA is mindful that Federal agencies have ''taken actions in the past decade to develop a robust CCUS regulatory framework to protect the environment and public health across multiple statutes.'' [6]

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

[6] Carbon Capture, Utilization, and Sequestration Guidance, 87 FR 8808, 8809 (February 16, 2022), *https://www.govinfo.gov/content/pkg/FR-2022-02-16/pdf/2022-03205.pdf.*

EPA's Greenhouse Gas Reporting Program; and safety regulations for CO_2 pipelines administered by the Pipeline and Hazardous Materials and Safety Administration (PHMSA). With respect to air emissions, some CCS projects may also require pre-construction permitting under the Clean Air Act's New Source Review (NSR) program and the adoption of additional emission limitations for non-GHG air pollutants based on applicable control technology requirements. The EPA invites public comment and feedback from stakeholders on all aspects of its proposed determination that CCS represents the BSER for certain new and existing fossil fuel-fired EGUs, including its evaluation of the various regulatory frameworks that apply to CCS.

CEQ's guidance, and the EPA's evaluation of BSER, recognizes that multiple Federal agencies have responsibility for regulating and permitting CCS projects, along with State and Tribal governments. The EPA is committed to working with Federal, State, and Tribal partners to ensure the responsible deployment of CCS, to protect communities from pollution, and to foster meaningful engagement with communities. 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 project development process. Furthermore, the EPA is requesting comment on what assistance states and pertinent stakeholders may need in conducting meaningful engagement with affected communities to ensure that there are adequate opportunities for public input on decisions to implement emissions control technology (including but not limited to CCS or low-GHG hydrogen).

II. General Information

A. Action Applicability

The source category that is the subject of these actions is comprised of the fossil fuel-fired electric utility generating units regulated under CAA section 111. 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 proposed actions are likely to affect.

The proposed amendments to 40 CFR part 60, subpart TTTT, once promulgated, will be directly applicable to affected facilities that began construction after January 8, 2014, and affected facilities that began reconstruction or modification after June 18, 2014. The proposed NSPS, proposed to be codified in 40 CFR part 60, subpart TTTTa, once promulgated, will be directly applicable to affected facilities that begin construction or reconstruction after the date of publication of the proposed standards in the **Federal Register**. Federal, State, local, and Tribal government entities that own and/or operate EGUs subject to 40 CFR part 60, subparts TTTT or TTTTa would be affected by these proposed amendments and standards.

The proposed emission guidelines for GHG emissions from fossil fuel-fired EGUs proposed to be codified in 40 CFR part 60, subpart UUUUb, once promulgated, will be applicable to states in the development and submittal of State plans pursuant to CAA section 111(d). After the EPA promulgates a final emission guideline, each State that has one or more designated facilities must develop, adopt, and submit to the EPA a State plan under CAA section 111(d). 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). If a State fails to submit a plan or the EPA determines that a State plan is not satisfactory, the EPA has the authority to establish a Federal CAA section 111(d) plan in such instances.

Under the Tribal Authority Rule adopted by the EPA, Tribes may seek authority 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 an emission guideline. 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. 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 this action is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposals and key technical documents at this same website.

Memoranda showing the edits that would be necessary to incorporate the changes to 40 CFR part 60, subpart TTTT and UUUUa and new 40 CFR part 60, subparts TTTTa and UUUUb proposed in these actions are available in the docket (Docket ID No. EPA–HQ–OAR–2023–0072). Following signature by the EPA Administrator, the EPA also will post a copy of the documents at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

C. Organization and Approach for These Proposed Rules

This rulemaking includes several proposed actions: (1) The EPA's proposed amendments to the Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (80 FR 64510; October 23, 2015) (2015 NSPS) and (2) proposed requirements for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. These actions also (3) propose to repeal the ACE Rule (84 FR 32523; July 8, 2019), (4) propose new emission guidelines for states in developing plans to reduce GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil- and natural gas-fired steam generating EGUs, and (5) propose new emission guidelines for states in developing plans to reduce GHG emissions from existing fossil fuel-fired stationary combustion turbines. The EPA proposes that each of these actions function independently and are therefore severable. The EPA invites comment on the question of which portions of these proposed rules, if any, should be severable.

Section III of this preamble provides updated information on the impacts of climate change. In section IV, the EPA provides a summary of recent developments in emissions controls and the electric power sector. Section V presents a summary of the statutory background and regulatory history. In section VI, the EPA summarizes stakeholder outreach efforts. In section VII, the EPA describes the proposed BSERs, standards of performance, and associated requirements for new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. In section

VIII, the EPA presents proposed amendments to requirements for new, reconstructed, and modified fossil fuel-fired steam generating units. In section IX, the EPA provides a summary of the ACE Rule and proposes its repeal. In section X, the EPA presents the proposed BSERs, degree of emission limitation, and related requirements for the proposed emission guidelines for existing fossil fuel-fired steam generating EGUs. In section XI, the EPA presents the proposed BSERs, degree of emission limitation, and related requirements for the proposed emission guidelines for existing natural gas-fired combustion turbines. Section XII presents the requirements for State plan development. In section XIII, the EPA describes the implications for these proposals on other EPA programs and rules. Section XIV describes the impacts of these proposals. Finally, in section XV, the EPA provides the statutory and executive order reviews.

III. Climate Change and Its Impacts

Elevated concentrations of GHGs are and have been warming the planet, leading to changes in the Earth's climate including changes in the frequency and intensity of heat waves, precipitation, and extreme weather events; rising seas; and retreating snow and ice. The changes taking place in the atmosphere as a result of the well-documented buildup of GHGs due to human activities are transforming the climate at a pace and scale that threatens human health, society, and the natural environment. Human-induced GHGs, largely derived from our reliance on fossil fuels, are causing serious and life-threatening environmental and health impacts.

Extensive additional 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 GHGs Under section 202(a) of the CAA (74 FR 66496; December 15, 2009).[7] In the 2009 Endangerment Findings, the Administrator found under section 202(a) of the CAA that elevated atmospheric concentrations of six key well-mixed GHGs—carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (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), and the science and observed changes have confirmed and strengthened the understanding and concerns regarding the climate risks considered in the Finding. The 2009 Endangerment Findings, 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 Findings further explained that compared to 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 Findings also documented, together with the extensive scientific and technical evidence in the supporting record, that climate change touches nearly every aspect of public welfare[8] in the U.S. including changes in water supply and quality due to increased frequency of 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; predominantly negative consequences for biodiversity and the provisioning of ecosystem goods and services; 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 similarly issued Endangerment and Cause or Contribute Findings for GHG emissions from aircraft under section 231(a)(2)(A) of the CAA (81 FR 54422; August 15, 2016).[9] In the 2016 Endangerment Findings, the Administrator found that the body of scientific evidence amassed in the record for the 2009 Endangerment Findings 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 the 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 Findings, the climate has continued to change, with new records being set for several climate indicators such as global average surface temperatures, GHG concentrations, and sea level rise. Moreover, heavy precipitation events have increased in the Eastern U.S. while agricultural and ecological drought has increased in the Western U.S. along with more intense and larger wildfires.[10] These and other trends are examples of the risks discussed in the 2009 and 2016 Endangerment Findings that have already been experienced. Additionally, major scientific assessments continue to demonstrate advances in our understanding of the climate system and the impacts that GHGs have on public health and welfare both for current and future generations. These updated observations and projections document the rapid rate of current and future climate change both

[7] In describing these 2009 Findings in these proposals, the EPA is neither reopening nor revisiting them.

[8] 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).

[9] In describing these 2016 Findings in these proposals, the EPA is neither reopening nor revisiting them.

[10] See later in this section for specific examples. An additional resource for indicators can be found at *https://www.epa.gov/climate-indicators.*

globally and in the U.S. These assessments include:

• U.S. Global Change Research Program's (USGCRP) 2016 Climate and Health Assessment [11] and 2017–2018 Fourth National Climate Assessment (NCA4).[12] [13]

• Intergovernmental Panel on Climate Change (IPCC) 2018 Global Warming of 1.5 °C,[14] 2019 Climate Change and Land,[15] and the 2019 Ocean and Cryosphere in a Changing Climate [16] assessments, as well as the 2021 IPCC Sixth Assessment Report (AR6).[17] [18]

• The National Academy of Sciences (NAS) 2016 Attribution of Extreme Weather Events in the Context of Climate Change,[19] 2017 Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide,[20] and 2019 Climate Change and Ecosystems [21] assessments.

• National Oceanic and Atmospheric Administration's (NOAA) annual State of the Climate reports published by the Bulletin of the American Meteorological Society,[22] most recently in August of 2022.

• EPA Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts (2021).[23]

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 as a result of both historic 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, the annual global average atmospheric concentrations of one of these GHGs, CO_2, measured at Mauna Loa in Hawaii and at other sites around the world reached 415 parts per million (ppm) in 2020 (nearly 50 percent higher than pre-industrial levels) [24] and has continued to rise at a rapid rate. Global average temperature has increased by about 1.1 degrees Celsius (°C) (2.0 degrees Fahrenheit (°F)) in the 2011–2020 decade relative to 1850–1900.[25] The years 2015–2021 were the warmest 7 years in the 1880–2020 record according to six different global surface temperature datasets.[26] The IPCC determined with medium confidence that this past decade was warmer than any multi-century period in at least the past 100,000 years.[27] 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.[28] The rate of sea level rise during the 20th Century was higher than in any other century in at least the last 2,800 years.[29] Higher CO_2 concentrations have led to acidification of the surface ocean in recent decades to an extent unusual in the past 2 million years, with negative impacts on marine organisms that use calcium carbonate to build shells or skeletons.[30] 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.[31] 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 [32] in many regions.[33]

The assessment literature demonstrates that modest additional amounts of warming may lead to a climate different from anything humans have ever experienced. The present-day CO_2 concentration of 415 ppm is already higher than at any time in the last 2 million years.[34] If concentrations exceed 450 ppm, they would likely be higher

[11] 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. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp.

[12] 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.

[13] 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.

[14] 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. Portner, 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.)].

[15] 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. Portner, 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.)].

[16] 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. Alegrı´a, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

[17] 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. Pe´an, 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.

[18] IPCC, 2022: Summary for Policymakers [H.-O. Pörtner, D.C. Roberts, E.S. Poloczanska, K. Mintenbeck, M. Tignor, A. Alegría, M. Craig, S. Langsdorf, S. Löschke, V. Möller, A. Okem (eds.)]. In: Climate Change 2022: Impacts, Adaptation and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [H.-O. Pörtner, D.C. Roberts, M. Tignor, E.S. Poloczanska, K. Mintenbeck, A. Alegría, M. Craig, S. Langsdorf, S. Löschke, V. Möller, A. Okem, B. Rama (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, New York, USA, pp. 3–33, doi:10.1017/9781009325844.001.

[19] 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.*

[20] 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.*

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

[22] 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.*

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

[24] 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.*

[25] IPCC, 2021.

[26] Blunden, J. and T. Boyer, Eds., 2022.

[27] IPCC, 2021.

[28] IPCC, 2021.

[29] 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.

[30] IPCC, 2021.

[31] IPCC, 2021.

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

[33] IPCC, 2021.

[34] IPCC, 2021.

than at any time in the past 23 million years: [35] At the current rate of increase of more than 2 ppm per year, this will occur in about 15 years. While buildup of GHGs is not the only factor that controls climate, it is illustrative that 3 million years ago (the last time CO_2 concentrations were this high) 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.[36]

If the Greenland and Antarctic ice sheets were to melt substantially, for example, sea levels would rise dramatically, with potentially severe consequences for coastal cities and infrastructure. The IPCC estimated that during the next 2,000 years, sea level will rise by 7 to 10 feet even if warming is limited to 1.5 °C (2.7 °F), from 7 to 20 feet if limited to 2 °C (3.6 °F), and by 60 to 70 feet if warming is allowed to reach 5 °C (9 °F) above preindustrial levels.[37] For context, almost all of the city of Miami is less than 25 feet above sea level, and the NCA4 stated that 13 million Americans would be at risk of migration due to 6 feet of sea level rise. Moreover, the CO_2 being absorbed by the ocean has resulted in changes in ocean chemistry due to acidification of a magnitude not seen in 65 million years,[38] putting many marine species—particularly calcifying species—at risk.[39]

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.[40] 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.[41] 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.[42]

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 and 62 million more people to frequent exceptional heatwaves (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''). This half degree temperature increase has been projected to lead to an increase in the frequency of sea-ice-free Arctic summers from once in a hundred 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 is projected to thaw over several centuries. Risks to food security is projected to 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 is projected to 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).[43] 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 is projected to 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, while the movement speed has decreased, and elevated sea levels have increased coastal flooding, all of which make these tropical cyclones more damaging.[44]

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.[45] 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.[46] 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, leading to salt water intrusion into coastal aquifers and groundwater, flooding streets, increasing storm surge damages, and threatening coastal property and ecosystems, requiring costly adaptive measures such as installation of pump stations, beach nourishment, property elevation, and shoreline armoring. 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

[35] IPCC, 2013.

[36] Gulev, S.K., P.W. Thorne, J. Ahn, F.J. Dentener, C.M. Domingues, S. Gerland, D. Gong, D.S. Kaufman, H.C. Nnamchi, J. Quaas, J.A. Rivera, S. Sathyendranath, S.L. Smith, B. Trewin, K. von Schuckmann, and R.S. Vose, 2021: Changing State of the Climate System. 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, New York, USA, pp. 287–422, doi:10.1017/9781009157896.004.

[37] IPCC, 2021.

[38] IPCC, 2018.

[39] IPCC, 2021.

[40] USGCRP, 2018.

[41] IPCC, 2018.

[42] IPCC, 2022.

[43] IPCC, 2018.

[44] IPCC, 2021.

[45] USGCRP, 2018.

[46] NIFC (National Interagency Fire Center). 2022. Total wildland fires and acres (1983–2020). Accessed November 2022. *https://www.nifc.gov/sites/default/files/document-media/TotalFires.pdf.*

security, both through direct impacts on military infrastructure, but also 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.[47]

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)[48] and cause ocean acidification. Nitrous oxide depletes the levels of protective stratospheric ozone.[49] The tropospheric ozone produced by the reaction of methane in the atmosphere has harmful effects for human health and plant growth in addition to its climate effects.[50]

Ongoing EPA modeling efforts can shed further light on the distribution of climate change damages expected to occur within the U.S. Based on methods from over 30 peer-reviewed climate change impact studies, the EPA's Framework for Evaluating Damages and Impacts (FrEDI) model has developed estimates of the relationship between future temperature changes and physical and economic climate-driven damages occurring in specific U.S. regions across 20 impact categories, which span a large number of sectors of the U.S. economy.[51] Recent applications of FrEDI have advanced the collective understanding about how future climate change impacts in these 20 sectors are expected to be substantial and distributed unevenly across U.S. regions.[52] Using this framework, the EPA estimates that under a global emission scenario with no additional mitigation, relative to a world with no additional warming since the baseline period (1986–2005), damages accruing to these 20 sectors in the contiguous U.S. occur mainly through increased deaths due to increasing temperatures, as well as climate-driven changes in air quality, transportation impacts due to coastal flooding resulting from sea level rise, increased mortality from wildfire emission exposure and response costs for fire suppression, and reduced labor hours worked in outdoor settings and buildings without air conditioning. The relative damages from long-term climate driven changes in these sectors are also projected vary from region to region: for example, the Southeast is projected to see some of the largest damages from sea level rise, the West Coast will see higher damages from wildfire smoke than other parts of the country, and the Northern Plains states are projected to see a higher proportion of damages to rail and road infrastructure. While the FrEDI framework currently quantifies damages for 20 sectors within the U.S., it is important to note that it is still a preliminary and partial assessment of climate impacts relevant to U.S. interests in a number of ways. For example, FrEDI does 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 occuring abroad have spillover effects in different regions of the U.S. See the FrEDI Technical Documentation[53] for more details.

These scientific assessments, 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

A. Introduction

In this section, we discuss background information about the electric power sector and then discuss several recent developments that are relevant for many of the controls that the EPA is proposing to determine qualify as the BSER for the fossil fuel-fired power plants that are the subject of this proposed rulemaking. After giving some general background, we first discuss CCS and explain that its cost has fallen significantly. Lower CCS costs are central for the EPA's proposals that CCS is the BSER for certain existing coal-fired EGUs and certain existing and new natural gas-fired combustion turbines. Second, we discuss natural gas co-firing for coal-fired EGUs and explain recent reductions in cost for this approach as well as its widespread availability and current and potential deployment within this source category. Third, we discuss hydrogen produced through low-emitting manufacturing, the availability of which is expected to increase significantly and the cost of which is expected to decline significantly in the near future. This increase in availability and decrease in cost is central for the EPA's proposal that low-GHG hydrogen is the BSER for certain existing and new natural gas-fired combustion turbines. Finally, we discuss key developments in the electric power sector that underly the expected operational methods for existing coal-fired EGUs and new and existing natural gas-fired combustion turbines. These key developments, in turn, are relevant for the regulatory design.

B. Background

1. Electric Power Sector

Electricity in the U.S. is generated by a range of technologies, and while the sector is rapidly evolving, the stationary combustion turbines and steam generating EGUs that are the subject of these proposed regulations still provide more than half of the electricity generated in the U.S. These EGUs fill many roles that are important to maintaining a reliable supply of electricity. For example, certain EGUs generate base load power, which is the portion of electricity loads that are continually present and typically

[47] USGCRP, 2018.

[48] Ziska, L., A. Crimmins, A. Auclair, S. DeGrasse, J.F. Garofalo, A.S. Khan, I. Loladze, A.A. Perez de Leon, 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://dx.doi.org/10.7930/J0ZP4417.*

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

[50] Nolte, C.G., P.D. Dolwick, N. Fann, L.W. Horowitz, V. Naik, R.W. Pinder, T.L. Spero, D.A. Winner, and L.H. Ziska, 2018: Air Quality. In 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, pp. 512–538. doi: 10.7930/NCA4. 2018. CH13.

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

[52] (1) Sarofim, M.C., Martinich, J., Neumann, J.E., *et al.* (2021). *A temperature binning approach for multi-sector climate impact analysis.* Climatic Change 165. *https://doi.org/10.1007/s10584-021-03048-6,* (2) *Supplementary Material for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,''* Docket ID No. EPA–HQ–OAR–2021–0317, September 2022, (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.

[53] EPA. (2021). Technical Documentation on the Framework for Evaluating Damages and Impacts (FrEDI). U.S. Environmental Protection Agency, EPA 430–R–21–004, available at *https://www.epa.gov/cira/fredi.*

operate throughout all hours of the year. Other EGUs provide complementary generation to balance variable supply and demand resources. ''Peaking units'' provide capacity during hours of the highest daily, weekly, or seasonal net demand. Some 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 [54] 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 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.

Generated electricity must be transmitted over networks [55] 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; [56] in others, individual utilities [57] coordinate the operations of their generation and transmission to balance the system across their respective service territories.

2. Types of EGUs

In 2021, approximately 61 percent of net electricity was generated from the combustion of fossil fuels with natural gas providing 38 percent, coal providing 22 percent, and petroleum products such as fuel oil providing an additional 1 percent.[58] Fossil fuel-fired EGUs include the steam generating units and stationary combustion turbines that are the subject of these proposed regulations.

There are two forms of fossil fuel-fired electric utility steam generating units: utility boilers and 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 repowered as natural gas-fired units. 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 combustion 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 power. An EGU's capacity factor indicates a power plant's electricity output as a percentage of its total generation capacity. Simple cycle combustion 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.[59]

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 nearly 41 percent of the overall net electricity supply in 2022. Many projections show this share growing over time. For example, the EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model post-IRA 2022 reference case (*i.e.,* the EPA's projections of the power sector, which includes representation of the IRA absent further regulation) shows zero-emitting sources reaching 76 percent of electricity generation by 2040. (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

[54] 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 (kWh), megawatt-hours (MWh), or gigawatt-hours (1 GWh = 1 million kWh).

[55] The three network interconnections are the Western Interconnection, comprising the western parts of both the U.S. and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the U.S. and Canada (except those parts of Eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses 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.*

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

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

[58] U.S. Energy Information Administration (EIA). *Electric Power Monthly, Table 1.1 and Form EIA–860M,* July 2022. *https://www.eia.gov/electricity/data/php.*

[59] 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.

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.'' [60]

C. CCS

One of the key GHG reduction technologies upon which BSER determinations are founded in this proposal is CCS—a technology that can capture and permanently store CO_2 from EGUs. CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Generally, the capture processes most applicable to combustion turbines and utility boilers remove CO_2 from the exhaust gas after combustion. The exhaust gases from most combustion processes are at atmospheric pressure with relatively low concentrations of CO_2. Most post-combustion capture systems utilize liquid solvents (most commonly amine-based) in a scrubber column to absorb the CO_2 from the flue gas.[61] 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).[62] Process improvements learned from earlier deployments of CCS, the availability of better solvents, and other advances have resulted in a decrease in the cost of CCS in recent years. 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.[63] In addition, new policies such as the IRA, enacted in 2022, support the deployment of CCS technology and will further reduce the cost of implementing CCS by extending and increasing the tax credit for CCS under Internal Revenue Code section 45Q.

There are several examples of the application of CCS at EGUs, some of which are noted here with further detail provided in section VII.F.3.b.iii(A) of this preamble. These include SaskPower's Boundary Dam Unit 3, a 110–MW lignite-fired unit in Saskatchewan, Canada, which has achieved CO_2 capture rates of 90 percent using an amine-based post-combustion capture system retrofitted to the existing steam generating unit.[64] Amine-based carbon capture has also been demonstrated at AES's Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) coal-fired power plants.[65]

CCS has also been successfully applied to an existing combined cycle combustion turbine EGU at the Bellingham Energy Center in south central Massachusetts, and other projects are in different stages of deployment. The 40–MW slipstream capture facility at the Bellingham Energy Center operated from 1991 to 2005 and captured 85 to 95 percent of the CO_2 in the slipstream.[66] In Scotland, the proposed 900–MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of deployment and will have the potential to capture 90 percent of its CO_2 emissions.[67] Moreover, an 1,800–MW combined cycle EGU that will be constructed in West Virginia and will utilize CCS has been announced. The project is planned to begin operation later this decade, and its economic feasibility was partially credited to the expanded IRC section 45Q tax credit for sequestered CO_2 provided through the IRA.[68]

In developing these proposals, the EPA reviewed the current state of CCS technology and costs, including the use of CCS with both steam generating units and combustion turbines. This review is reflected in the BSER discussions later in this preamble and is further detailed in the accompanying RIA and technical support documents titled, *GHG Mitigation Measures for Steam Generating Units* and *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines.* The three documents are included in the rulemaking docket.

D. 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.'' Most 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 typically involves the installation of new gas burners and related boiler modifications as well as the construction of natural gas supply pipelines. In recent years, the cost of natural gas co-firing has declined because the expected difference between coal and gas prices has decreased to about $1/MMBtu and recent analyses support lower capital costs for modifying existing boilers to co-fire with natural gas, as discussed in section X.D.2 of this preamble.

In developing these proposals, 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 *GHG Mitigation Measures for Steam Generating Units* TSD. Both documents are included in the rulemaking docket.

E. Hydrogen Co-Firing

Industrial combustion turbines have been burning byproduct fuels containing large percentages of hydrogen for decades, and recently, utility combustion turbines in the power sector have begun to co-fire hydrogen as

[60] 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.* Pg. 5. Public comments submitted to the EPA's pre-proposal rulemaking, Docket ID No. EPA–HQ–OAR–2022–0723.

[61] Post-combustion CO_2 capture is most common, but as discussed later in this preamble, there are also pre-combustion CO_2 capture options available and applicable to the power sector.

[62] 40 CFR 261.4(h).

[63] 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.*

[64] 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.*

[65] 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.

[66] 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.*

[67] 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/.*

[68] 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-combinedcycle-natural-gas-power-station-with-carbon-capture-announced-in-west-virginia/.*

a fuel to generate electricity. Hydrogen contains no carbon, and when combusted in a turbine, produces zero direct CO_2 emissions. However, as discussed in section IV.F.3 of this preamble, the manufacture of hydrogen, depending on the method of production, can generate GHG emissions. As noted previously, there has been a growing interest in the use of hydrogen as a fuel for combustion turbines to generate electricity. Many models of new utility combustion turbines have demonstrated the ability to co-fire up to 30 percent hydrogen and developers are working toward models that will be ready to combust 100 percent hydrogen by 2030. Furthermore, several utilities are co-firing hydrogen in test burns; and some have announced plans to move to combusting 100 percent hydrogen in the 2035–2045 timeframe. Specifically, the Los Angeles Department of Water and Power's (LADWP) Scattergood Modernization project includes plans to have a hydrogen-ready combustion turbine in place when the 346–MW combined cycle plant (potential for up to 830 MW) begins initial operations in 2029. LADWP foresees the plant running on 100 percent electrolytic hydrogen by 2035.[69] In addition, LADWP also has an agreement in place to purchase electricity from the Intermountain Power Agency project (IPA) in Utah. IPA is replacing an existing 1.8–GW coal-fired EGU with an 840–MW combined cycle turbine that developers expect to initially co-fire 30 percent electrolytic hydrogen in 2025 and 100 percent hydrogen by 2045.[70] In Florida, NextEra Energy has announced plans to operate 16 GW of existing natural gas-fired combustion turbines with electrolytic hydrogen as part of the utility's Zero Carbon Blueprint to be carbon-free by 2045.[71] Duke Energy Corporation, which operates 33 gas-fired plants across the Midwest, the Carolinas, and Florida, has outlined plans for full hydrogen capabilities throughout its future turbine fleet: ''All natural gas units built after 2030 are assumed to be convertible to full hydrogen capability. After 2040, only peaking units that are fully hydrogen capable are assumed to be built.'' [72]

In addition to those three utility announcements, several merchant generators operating in wholesale markets are also signaling their intent to ramp up hydrogen co-firing levels after initial 30 percent co-firing phases. The Cricket Valley Energy Center (CVEC) in New York is retrofitting its combined cycle power plant starting in 2022 as a first step toward the conversion to a 100 percent hydrogen fuel capable plant. CVEC announcements did not have specific dates for 100 percent electrolytic hydrogen firing but indicated in its announcement that New York has mandated achieving a zero-emission electricity sector by 2040.[73] The Long Ridge Energy Terminal in Ohio, which is has successfully co-fired a 5 percent hydrogen blend at its 485–MW combined cycle plant, noted its technology has the capability to transition to 100 percent hydrogen over time as its low-GHG fuel supply becomes available.[74] Constellation Energy, which owns 23 natural gas-fired or dual fuel generators (8.6 GW), is exploring electrolytic hydrogen co-firing across its fleet. It estimated costs for blend levels in the range of 60–100 percent at approximately $100/kW for retrofits and noted that equipment manufacturers are planning 100 percent hydrogen combustion-ready turbines before 2030.[75]

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. These incentives are fueling interest in co-firing hydrogen and creating expectations that the availability of low-cost and low-GHG hydrogen will increase in the coming years. These projections are based on a combination of economies of scale as low-GHG production methods expand, the increasing availability of low-cost electricity—largely powered by renewable energy sources and potentially nuclear energy—and learning by doing as more turbine projects are developed.

In developing these proposals, the EPA reviewed in detail the current state of hydrogen 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 technical support document titled, *Hydrogen in Combustion Turbine Electric Generating Units.* Both documents are included in the rulemaking docket.

F. Recent Changes in the Power Sector

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 with more efficient and lower cost alternatives.

These developments have significant implications for the types of controls that the EPA proposes to determine qualify as the BSER for different types of fossil fuel-fired EGUs. For example, many utilities and power plant operators have announced plans to voluntarily cease operating coal-fired power plants in the near future, in some cases after operating them at low levels for a several-year period. Industry stakeholders have requested that the EPA structure this rule to avoid imposing costly control obligations on coal-fired power plants that have announced plans to voluntarily cease operations, and the EPA proposes to accommodate those requests. 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 proposing as the BSER for these turbines.

This section discusses the recent trends in the power sector. It also includes a summary of the provisions and incentives included in recent Federal legislation that will impact the power sector as well as State actions and commitments by power producers to reduce GHG emissions. The section

[69] *https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf.*

[70] *https://www.forbes.com/sites/mitsubishiheavyindustries/2021/07/30/eager-to-become-hydrogen-ready-power-plants-turn-to-dual-fuel-turbines/?sh=38ddea053476.*

[71] *https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/NextEraEnergyZeroCarbonBlueprint.pdf.*

[72] *https://www.duke-energy.com/_/media/PDFs/our-company/Climate-Report-2022.pdf.*

[73] *https://www.cricketvalley.com/news/cricket-valley-energy-center-and-ge-sign-agreement-to-help-reduce-carbon-emissions-in-new-york-with-green-hydrogen-fueled-power-plant/.*

[74] GE-powered gas-fired plant in Ohio now burning hydrogen (*power-eng.com*).

[75] Constellation Energy Corporation's Comments on EPA Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units Docket ID No. EPA–HQ–OAR–2022–0289–0022.

concludes with projections of future trends in power sector generation.

2. Broad Trends Within the Power Sector

For more than a decade, the power sector has experienced 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; changes in electricity demand across the broader economy; growth and regional changes in the U.S. population; 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, the existing fleet of coal-fired EGUs continues to age and become more costly to maintain and operate. At the same time, the supply and availability of natural gas has increased significantly, and its price has held relatively low. For the first time, in April 2015, natural gas surpassed coal in monthly net electricity generation and since that time has maintained its position as the primary fossil fuel for base load energy generation, for peaking applications, and for balancing renewable generation.[76] 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, carbon capture and storage and associated infrastructure, advanced geothermal systems, and advanced distributed energy resources (DER) as well as more traditional wind and solar resources. The IRA provides numerous tax and other incentives to directly spur deployment of clean energy technologies. Particularly relevant to these proposals, the incentives in the IRA,[77] which are discussed in detail later in this section of the preamble, support the expansion of technologies, such as CCS and hydrogen technologies, that reduce GHG emissions from fossil-fired units.

The ongoing transition of the power sector is illustrated by a comparison of data between 2010 and 2021. In 2010, approximately 70 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 2021, fossil fuel net generation was approximately 60 percent, less than the share in 2010 despite electricity demand remaining relatively flat over this same time period. Moreover, the share of fossil generation supplied by coal-fired EGUs fell from 46 percent in 2010 to 23 percent in 2021 while the share supplied by natural gas-fired EGUs rose from 23 to 37 percent during the same period. In absolute terms, coal-fired generation declined by 51 percent while natural gas-fired generation increased by 64 percent. This reflects both the increase in natural gas capacity as well as an increase in the utilization of new and existing gas-fired EGUs. The combination of wind and solar generation also grew from 2 percent of the electric power sector mix in 2010 to 12 percent in 2021.[78]

The broad trends throughout the power sector can also be seen in the number of commitments and announced plans of many EGU owners and operators across the industry to decarbonize—spanning all types of companies in all locations. Moreover, State governments, which traditionally regulate investment decisions regarding electricity generation, have implemented their own policies to reduce GHG emissions from power generation.

Additional analysis of the utility power sector, including projections of future power sector behavior and the impacts of these proposed rules, is discussed in more detail in section XV of this preamble, in the accompanying RIA, and in the *Power Sector Trends* technical support document (TSD). The latter two documents are available in the rulemaking docket. Consistent with analyses done by other energy modelers, the RIA and TSD demonstrate that the sector trend of moving away from coal-fired generation is likely to continue and that non-emitting technologies may eventually displace certain natural gas-fired combustion turbines.

3. 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.[79] 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.[80] 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 and/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.[81] And with no new coal-fired steam generating units commencing construction in more than a decade—and with the EPA unaware of any plans by any companies 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 2010, the power sector's total installed capacity[82] has increased by

[76] 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.*

[77] 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.*

[78] 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/.*

[79] 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.*

[80] 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/.*

[81] 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.*

[82] 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

144 GW (14 percent), while coal-fired steam generating unit capacity has declined by 107 GW. This reduction in coal-fired steam generating unit capacity was offset by an increase in total installed wind capacity of 93 GW, natural gas capacity of 84 GW, and an increase in utility-scale solar capacity of 60 GW during the same period. Additionally, significant amounts of DER solar (33 GW) were also added. Two-thirds or more of these changes were in the most recent 6 years of this period. From 2015–2021, coal capacity was reduced by 70 GW and this reduction in capacity was offset by a net increase of 60 GW of wind capacity, 52 GW of natural gas capacity, and 47 GW of utility-scale solar capacity. Additionally, 23 GW of DER solar were also added from 2015 to 2021.

At the end of 2021, there were more than 500 EGUs totaling 212 GW of coal-fired capacity remaining in the U.S. 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.[83] Moreover, average annual capacity factors for coal-fired steam generating units have declined from 67 to 49 percent since 2010,[84] indicating that a larger share of units are operating in non-base load fashion.

Older power plants also tend to become uneconomic over time as they become more costly to maintain and operate,[85] 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 2021 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.[86] To further illustrate this trend, the existing coal-fired steam generating units older than 40 years represent 71 percent (154 GW)[87] of the total remaining capacity. In fact, more than half (118 GW) of the coal-fired steam generating units still operating have already announced retirement dates prior to 2040.[88] As discussed further 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 1,200 million short tons (MMst) followed by sharp declines in 2015 and 2020.[89] In 2015, less than 900 MMst were produced, and in 2020, the total dropped to 535 MMst, the lowest output since 1965.

4. Trends in 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.

Natural gas consists primarily of methane, and after the raw gas is extracted from the ground, it is processed to remove impurities and to separate the methane from other gases and natural gas liquids to produce pipeline quality gas.[90] This gas is sent to intermediate storage facilities prior to being piped through transmission feeder lines to a distribution network on its path to storage facilities or end users. During 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.

According to the U.S. Energy Information Administration (EIA), annual natural gas marketed production in the U.S. remained consistent at approximately 20 trillion cubic feet (Tcf) from the 1970s to the early 2000s. However, since 2005, annual natural gas marketed production has steadily increased and approached 35 Tcf in 2021, which is an average of approximately 94.6 billion cubic feet per day.[91] Thirty-four states produce natural gas with Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7 percent) accounting for approximately 70 percent of total production. Natural gas production exceeded consumption in the U.S. for the first time in 2017.

As the production of natural gas has increased, the annual average price has declined during the same period.[92] In 2008, U.S. natural gas prices peaked at $13.39 per million British thermal units ($/MMBtu) for residential customers. By 2020, the price was $10.45/MMBtu. The decrease in average annual natural gas prices can also been seen in city gate prices (*i.e.,* a point or measuring station where natural gas is transferred from long-distance pipelines to a local distribution company), which peaked in 2008 at $8.85/MMBtu. By 2020, city gate prices were $3.30/MMBtu. An equivalent $/MMBtu basis is a common way to compare natural gas and coal fuel prices. For example, the price of Henry Hub natural gas in July 2022 was $7.39/MMBtu while the spot price of Central Appalachian coal was $7.25/MMBtu for the same month. However, this method of fuel price comparison based on equivalent energy content does not reflect differences in energy conversion efficiency (*i.e.,* heat rate) and other factors among different types of generators. Because natural gas-fired combustion turbines are more efficient than coal-fired steam units, any fuel cost comparison should include an efficiency basis (dollar per megawatt-hour) to the equivalent energy content. For illustrative purposes, an EIA comparison based on this method showed that the Henry Hub natural gas

fossil heat source unless otherwise stated. This includes combined cycle, simple cycle, steam, and miscellaneous (<1 percent).

[83] 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.*

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

[85] 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.*

[86] 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.

[87] 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/.*

[88] 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.*

[89] U.S. Energy Information Administration (EIA). Annual Coal Report. Table ES–1. October 2022. *https://eia.gov/coal/annual/pdf/tableES1.pdf.*

[90] U.S. Energy Information Administration (EIA). Natural Gas Explained. December 2022. *https://www.eia.gov/energyexplained/natural-gas/.*

[91] U.S. Energy Information Administration (EIA). Natural gas explained. Where our natural gas comes from. *https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php.*

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

price in July 2022 was $59.18/MWh and the price for Central Appalachian coal was $78.25/MWh for the same month.[93]

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 renewable 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. Of this total, approximately 147 GW (70 percent) were combined cycle capacity and 65 GW were simple cycle capacity.[94] From 2007 to 2021, more than 125 GW of capacity were constructed and approximately 78 percent of that total were combined cycle EGUs. This figure represents an average of almost 4.2 GW of new combustion turbine generation capacity per year. In 2021, the net summer capacity of combustion turbine EGUs totaled 413 GW, with 281 GW being combined cycle generation and 132 GW being simple cycle generation.

This trend away from coal to natural gas is also reflected in comparisons of annual capacity factors, sizes, and ages of affected EGUs. For example, the annual average capacity factors for natural gas-fired units increased from 28 to 37 percent between 2010 and 2021. 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.[95]

As explained in greater detail later in this preamble and in the accompanying RIA, future capacity 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, energy storage, and other technologies, as discussed in section IV.I. Approximately, 86 percent of capacity additions in 2023 are expected to be from non-emitting generation resources including solar, wind, nuclear, and energy storage.[96] The IRA is likely to accelerate this trend, which is also expected to impact the operation of certain combustion turbines. For example, as the electric output from additional non-emitting 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.

5. Trends in Renewable Generation

Renewable sources of electric generation—especially solar and wind—have expanded in the U.S. during the past decade. This growth has coincided with a reduction in the costs of the technologies, supportive State and Federal policies, and increased consumer demand for low-GHG electricity. In 2021, renewable energy sources produced approximately 20 percent of the nation's net generation, led by wind (9.2 percent), hydroelectric (6.3 percent), solar (2.8 percent), and other sources such as geothermal and biomass (1.7 percent).[97]

The costs of renewable energy sources have fallen over time due to technological advances, improvements in performance, and increased demand for clean energy. For example, the unsubsidized average levelized cost of wind energy from 1988 to 1999 was $106/MWh and has since declined to $32/MWh in 2021.[98] The average levelized cost of energy for utility-scale solar photovoltaics has fallen from $227/MWh in 2010 to $33/MWh in 2021.[99] And the National Renewable Energy Laboratory (NREL) has documented cost decreases of 64, 69, and 82 percent, respectively, for residential-, commercial-, and utility-scale solar installations since 2010.[100] Local, State, and Federal incentives and tax credits have further reduced the cost of renewable energy resources.

During the past 15 years, more than 122 GW of wind (primarily onshore) and 61 GW of solar capacity have been constructed, which represent a tripling of wind capacity and a 20-fold increase in solar capacity.[101] Prior to 2007, no more than 2.6 GW of new wind capacity was built in any year, and the wind capacity added from 2000 to 2006 averaged 1.2 GW per year. In 2007, the nation added 5.3 GW of total wind capacity and the annual average was 7.2 GW through 2019. Wind capacity additions peaked in the past 2 years at a total of nearly 29 GW. For solar, the pattern of expansion is similar. For example, from 2000 to 2006, a total of 11 MW of new solar capacity was constructed, and from 2007 to 2011, total capacity additions increased to 1.2 GW. However, from 2012 to 2019, more than 36 GW of solar capacity was built (an average of 4.5 GW per year). And in 2020 and 2021, new solar capacity totaled of 24 GW. In terms of the net operating share of summer capacity in 2021, wind produced 46 percent of all renewable energy while solar generated 21 percent. The remaining electricity generated from renewables included 28 percent from hydroelectric and 5 percent from other sources that include geothermal systems, biogases/biomethane from landfills, woody materials and other biomass, and municipal solid waste.

There are also emerging technologies such as battery storage that have demonstrated the ability to further support the development and integration of renewable energy to the grid by balancing variable supply and demand resources. At the end of 2021, there were 331 large-scale battery storage systems operating in the U.S. with a combined capacity of 4.8 GW

[93] U.S. Energy Information Administration (EIA). *Electric Monthly Update.* September 23. 2022. Report derived from Bloomberg Energy. EIA notes that the competition between coal and natural gas to produce electricity is complex, involving delivered prices and emission costs, the terms of fuel supply contracts, and the workings of fuel markets.

[94] 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/.*

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

[96] U.S. Energy Information Administration (EIA). Today in Energy. More than half of new U.S. electric-generating capacity in 2023 will be solar. February 2023. *https://www.eia.gov/todayinenergy/detail.php?id=55419.*

[97] U.S. Energy Information Administration (EIA). Monthly Energy Review, table 7.2B Electricity Net Generation: Electric Power Sector, May 2022. *https://www.eia.gov/totalenergy/data/monthly/.*

[98] U.S. Department of Energy (DOE), Land-Based Wind Market Report: 2022 Edition, 2022. *https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2022-edition.*

[99] Lawrence Berkeley National Laboratory (LBNL), Utility-Scale Solar Technical Brief, 2022 Edition, September 2022. *https://emp.lbl.gov/utility-scale-solar.*

[100] *https://www.nrel.gov/news/program/2021/documenting-a-decade-of-cost-declines-for-pv-systems.html.*

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

(10.7 GWh).[102] In terms of small-scale battery storage, there were 781 MW of reported capacity in 2021, mostly in California.[103] Energy storage costs declined 72 percent between 2015 and 2019,[104] and declining costs have led to additional capacity being installed at each facility, and this increases the duration of each system when operating at maximum output. With 20.8 GW of grid storage already announced for 2023–2025, EIA expects that capacity will more than triple from 7.8 GW in late 2022 to approximately 30 GW by the end of 2025.[105]

6. Trends in Nuclear Generation

The U.S. power sector continues to rely on nuclear sources of energy for a consistent portion of net generation. Since 1990, nuclear energy has provided about 20 percent of the nation's electricity, and 92 reactors were operating at 54 nuclear power plants in 28 states in 2022.[106]

It should be noted that despite the consistent output from nuclear power plants over time, the number of operating reactors has recently declined. The average retirement age for a nuclear reactor is 44 years and the average age of the remaining nuclear fleet is currently 42 years, although age is only one consideration for determining when a nuclear plant may retire. For example, nuclear generating units at Dominion Generation's Surry plant, Florida Power & Light's Turkey Point plant, and Constellation Energy's Peach Bottom plant applied to the Nuclear Regulatory Commission (NRC) for second 20-year license renewals and subsequent renewed licenses were granted for six units, although four of the six units have not had their license terms extended beyond the periods of their first renewed licenses and are undergoing further environmental review.[107] Others who have applied to the NRC for a second 20-year license renewal include Dominion for its North Anna units 1 and 2; NextEra Energy for its Point Beach units 1 and 2; Duke Energy Carolinas for its Oconee units 1, 2, and 3; Florida Power & Light for its St. Lucie units 1 and 2; and Northern States Power Company for its Monticello unit 1. If granted, these additional licenses would also extend the lifespans of these units well past the 42-year average. Recent State and Federal policies, including the DOE's $6 billion Civilian Nuclear Credit program enacted by the IIJA and the 45U tax credit (discussed below), are intended to support the continued operation of existing nuclear power plants.

There is also interest in the next generation of nuclear technologies. Small modular nuclear reactors, which can provide both firm dispatchable power and load-following capabilities to balance greater volumes of variable renewable generation, could play a role in future energy generation. The NRC has issued a final rule certifying the first small modular reactor design.[108] Expectations with respect to output from advanced nuclear generation vary, from negligible on the low end to as high as between 1,400 and 3,600 terawatt-hours per year by 2050.[109] According to one survey by the Nuclear Energy Institute, utilities are currently considering building more than 90 GW of small modular nuclear reactors by 2050.[110]

G. 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.[111]

The amount of CO_2 emitted from fossil fuel-fired EGUs depends on the carbon content of the fuel and 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 amount of CO_2 produced when a fuel is burned is a function of the carbon content of the fuel. 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.[112 113] 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).[114] 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 [115] (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 [116] of GHGs, including CO_2 emissions, for the years 1990–2020.

According to the latest inventory, in 2021, total U.S. GHG emissions were 6,340 million metric tons of carbon dioxide equivalent (MMT CO_2e). The transportation sector (28.5 percent) was the largest contributor to total U.S. GHG emissions, followed by the power sector (25.0 percent) and industrial sources

[102] U.S. Energy Information Administration (EIA). Annual Electric Generator Report, 2021 Form EIA–860. *https://www.eia.gov/electricity/data/eia860/.*

[103] U.S. Energy Information Administration (EIA). Annual Electric Power Industry Report, 2021 Form EIA–861. *https://www.eia.gov/electricity/data/eia861/.*

[104] U.S. Energy Information Administration (EIA). Annual Electric Generator Report, 2019 Form EIA–860. *https://www.eia.gov/analysis/studies/electricity/batterystorage/.*

[105] U.S. Energy Information Administration (EIA). Today in Energy. *U.S. battery storage capacity will increase significantly by 2025.* December 2022. *https://www.eia.gov/todayinenergy/detail.php?id=54939.*

[106] 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/.*

[107] U.S. Nuclear Regulatory Commission (NRC). Status of Subsequent License Renewal Applications. April 2023. *https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html.*

[108] 88 FR 3287 (January 19, 2023).

[109] Stein, A., Messinger, J., Wang, S., Lloyd, J., McBride, J., Franovich, R. (July 6, 2022). ''*Advancing Nuclear Energy: Evaluating Deployment, Investment, and Impact in America's Clean Energy Future.*'' Breakthrough Institute. *https://thebreakthrough.imgix.net/Advancing-Nuclear-Energy_v3-compressed.pdf.*

[110] Derr, E. (July 29, 2022). *Energy Studies and Models Show Advanced Nuclear as the Backbone of Our Carbon-Free Future.* Nuclear Energy Institute (NEI). *https://www.nei.org/news/2022/studies-and-models-show-demand-for-adv-nuclear.*

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

[112] 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.*

[113] 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.

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

[115] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. https://cfpub.epa.gov/ghgdata.*

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

(23.5 percent). In terms of annual CO_2 emissions, the power sector was responsible for 30.6 percent (1,541 MMT CO_2e) of the nation's 2021 total.

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).[117] The reduction in CO_2 emissions can be attributed to the power sector's ongoing trends 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.[118] This total dropped to 1,351 MMT in 2015 and reached 974 MMT in 2019, the first time since 1978 that coal-fired CO_2 emissions were below 1,000 MMT. In 2020, emissions of CO_2 from coal-fired EGUs measured 788 MMT before rebounding in 2021 to 909 MMT due to increased demand. 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.

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).[119] 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 so 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.

The Legislative, Market, and State Law Context

Recent Legislation Impacting the Power Sector

On November 15, 2021, President Biden signed the IIJA[120] (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[121] that will impact the utility power sector include: $16.5 billion to build and upgrade the nation's electric grid; $6 billion in financial support for existing nuclear reactors that are at risk of closing and being replaced by high-emitting resources; 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. Other clean energy technologies with IIJA funding include carbon capture, geologic sequestration, direct air capture, grid-scale energy storage, and advanced nuclear reactors. States, Tribes, local communities, utilities, and others are eligible to receive funding.

The IRA, which President Biden signed on August 16, 2022,[122] has the potential for even greater impacts on the electric power sector. With an estimated $369 billion in Energy Security and Climate Change programs over the next 10 years, covering grant funding and tax incentives, the IRA provides significant investments in 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. These provisions are aimed at reducing emissions of GHGs from new and existing generating assets, with tax credits for carbon capture, utilization, and storage (CCUS) and clean hydrogen production providing a pathway for the use of coal and natural gas as part of a low-GHG electricity grid. Finally, with provisions such as the Methane Emissions Reduction Program, Congress demonstrated a focus on the importance of actions to address methane emissions from petroleum and natural gas systems.

To assist states and utilities in their decarbonizing efforts, and most germane to these proposed rulemakings, 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

[117] 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.*

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

[119] 80 FR 63662 (October 23, 2015).

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

[121] *https://gfoaorg.cdn.prismic.io/gfoaorg/0727aa5a-308f-4ef0-addf-140fd43acfb5_BUILDING-A-BETTER-AMERICA-V2.pdf.*

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

enhanced oil recovery (EOR).[123] 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 45Q can be combined with 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.[124] The magnitude of this incentive is driving investment and announcements, evidenced by the increased number of permit applications for geologic sequestration.

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 from well-to-gate. The credits range from $3/kg H_2 for 0.0 to 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 GHG emissions greater than 4.0 kg CO_2e/kg H_2 are not eligible. According to the DOE, current costs for hydrogen produced from renewable energy are approximately $5/kg H_2.[125] These production costs could decline by 2025 to between $2.5 and $2.7/kg H_2 (not including the production tax credits).[126]

The clean hydrogen production tax credit is expected to incentivize the production of low-GHG hydrogen and ultimately exert downward pressure on costs.[127] Low-cost and widely available low-GHG hydrogen has the potential to become a material decarbonization lever in the power sector as the use of low-GHG hydrogen in stationary combustion turbines reduces direct GHG emissions as hydrogen releases no CO_2 when combusted. The tiered eligibility requirements for the clean hydrogen production tax credit also incentivize the lowest-GHG emissions production processes.

Both IRC 45Q and 45V are eligible for additional provisions that increase the value and usability of the credits. Certain tax-exempt entities, such as electric co-ops, may use direct pay 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 45Q or 45V credits for five 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.

The production tax credit is not the only provision in the IRA designed to incentivize low-GHG hydrogen. Projects may also access an investment tax credit (ITC) under IRC section 48. For example, manufacturers of clean hydrogen production equipment, like electrolyzers, may apply under IRC section 48C (the Advanced Manufacturing Tax Credit). And the manufacturing facility for electrolyzers could receive credits under section 48C while the resulting hydrogen production facility could then earn credits under section 45V (this form of stacking is allowed by statute). However, the same project may not claim ITC credits under section 48C while claiming PTC credits under section 45V. Projects may not generally combine credits from IRC section 45V with credits in IRC section 45Q. Hydrogen production tax credits became available in January 2023 for eligible new projects. Entities that commence construction between 2023 and 2032 can claim credits for the first 10 years of production.

The magnitude of this incentive—combined with those in the IIJA such as the $8 billion for regional hydrogen hubs and $1.5 billion for electrolyzer advancement—should accelerate the production of low-GHG hydrogen for use in a broad range of applications across many sectors, including the utility power sector.[128]

Many of the IRA tax credit incentives are directed toward low- and zero-emission electric generation. They are designed to lower costs and market barriers to bring new zero-emitting generation and energy storage capacity online, to retain existing zero-emitting generators, and the energy efficiency tax credits are designed to reduce electricity demand. These financial tools have been used historically and shown to be a principal policy driver, buttressed by State renewable and clean energy standards, for incentivizing deployment of low- and zero-emitting generation.[129] [130]

For example, the IRA expanded and extended the existing section 13101 (IRC section 45) production tax credits for new solar, wind, geothermal, and other eligible zero- or low-GHG emissions energy sources. The production tax credit (PTC) provides credits in a 10-year stream for each MWh of clean energy produced. The IRA indexed the PTC on inflation, increasing the credit amount to $27.50/MWh for facilities meeting certain wage and apprenticeship requirements. For context, the energy price in the nation's largest wholesale energy market, PJM,[131] is typically between $20/MWh and $90/MWh depending on timing, load, and transmission congestion.

In parallel, the existing investment tax credits in section 13101 (IRC section 48) were also expanded and extended in the IRA. Taxpayers must elect between the ITC and the PTC for each applicable project. The ITC enables taxpayers to recoup up to 30 percent of project costs for technologies such as solar, geothermal, fiberoptic solar, fuel cells, microturbines, small wind, offshore wind, combined heat and power (CHP), and waste energy recovery for investments meeting certain wage and apprenticeship requirements. There are also a range of bonus credits available

[123] 26 U.S.C. 45Q.

[124] 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*.

[125] U.S. Department of Energy (DOE). Hydrogen and Fuel Cell Technologies Office. Hydrogen Shot. *https://www.energy.gov/eere/fuelcells/hydrogen-shot*.

[126] U.S. Department of Energy (DOE). Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://www.energy.gov/articles/doe-releases-new-reports-pathways-commercial-liftoff-accelerate-clean-energy-technologies*.

[127] Larsen, J., King, B., Kolus, H., Dasari, N., Hiltbrand, G., Herndon, W. (August 12, 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/*.

[128] U.S. Department of Energy (DOE). Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://www.energy.gov/articles/doe-releases-new-reports-pathways-commercial-liftoff-accelerate-clean-energy-technologies*.

[129] *Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions,* National Renewable Energy Laboratory (NREL), February 2016.

[130] *A Retrospective Assessment of Clean Energy Investments in the Recovery Act,* February 2016, U.S. Executive Office of the President, Memorandum.

[131] PJM Interconnection LLC (PJM) is a regional transmission organization (RTO) serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

if certain criteria are met, for example for meeting domestic content and energy communities' requirements with each earning an additional 10 percent credit. The IRA expanded eligibility to include storage technologies as well as some non-storage technologies.

The IRA also tied the availability of tax credits explicitly to reductions of GHG emissions from the power sector. Sections 13701 and 13702 enacted technology-neutral production and investment tax credits for projects placed in service after 2025 that have GHG emissions rates of zero or less. These credits are available until the phaseout is triggered when the power sector's GHG emissions fall below 25 percent of 2022 levels.

Following State practices, Congress also included a zero-emission nuclear power production credit in the IRA to ensure existing in-service nuclear generators are retained for their contribution to base load zero-carbon emitting electricity. When labor and apprenticeship requirements are met, the credit price is $15/MWh. The credit amount declines when gross receipts of services provided with electricity rise above a specified level. The program begins in 2024 with credit streams available for nine years. This PTC is complementary to the $6 billion for nuclear advancements the IIJA authorized and appropriated to the DOE. New nuclear plants, including small modular reactors, would be eligible for either the technology-neutral Clean Electricity Production or Investment Credit (IRC section 45Y and 48E).

In the evaluation of these proposed actions, many of the technologies that receive investment under recent Federal legislation are not directly considered, as the EPA has not evaluated the new generation technologies that entities could employ as alternatives to fossil fuel-fired EGUs in its assessment of the BSER. As the discussion of that assessment will make clear later in this preamble, the EPA's inquiry has focused on ''measures that improve the pollution performance of individual sources.'' [132] However, these overarching incentives and policies are important context for this rulemaking.

The following section (section IV.E.2) includes a review of integrated resource plans (IRPs) filed by public utilities that prioritize GHG reductions. IRPs demonstrate how utilities plan to meet future forecasted energy demand while ensuring reliable and cost-effective service. These IRPs demonstrate that most power companies intend to meet their GHG reduction targets by 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. Many IRPs further demonstrate the realization of power companies that to meet their GHG reduction targets, their natural gas-fired assets will need to occupy a much smaller GHG footprint through a combination of hydrogen, CCS, and reduced utilization. The IRA is designed to encourage this trend. For example, in addition to the provisions outlined above, including the 10 percent bonus value applied in 'energy communities' that include fossil-related properties, the IRA created grant and loan funding sources for hard-to-abate energy assets. Section 22004 of the IRA authorizes $9.7 billion in financing for rural electric co-operatives and providers to invest in cleaner technologies to achieve GHG reductions across rural electric systems while buttressing resilience and reliability. Additionally, section 50144 of the IRA, known as the Energy Infrastructure Reinvestment Financing provision, provides $5 billion for backing $250 billion in low-cost loans for utilities to repower, repurpose, or replace existing infrastructure that has ceased operations, or to enable operating energy infrastructure to reduce air pollution or GHG emissions. The financing in this provision enables a utility to repurpose an existing fossil site, such as a retired coal-fired power plant, or add CCS, renewable generation, or hydrogen capability to an operating coal- or natural gas-fired power plant and retain community jobs while reducing GHG emissions.

2. Commitments by Utilities To Reduce GHG Emissions

The broad trends away from coal-fired generation and toward lower-emitting generation are reflected in the recent actions and announced plans of many utilities across the industry. As highlighted later in this section, through planning documents, IRPs, filings with State and local public utility commissions, and news releases, many utilities have made public commitments to voluntarily cease operating coal-fired generation and move toward zero- and low-GHG energy generation. Many utilities and other power generators have announced plans to increase their renewable energy holdings and continue reducing GHG emissions, regardless of any potential Federal regulatory requirements. For example, 50 power producers that are members of the Edison Electric Institute have announced CO_2 reduction goals, two-thirds of which include net-zero carbon emissions by 2050.[133] This trend is not unique to the largest owner-operators of coal-fired EGUs; smaller utilities, public power cooperatives, and municipal entities are also contributing to these changes.

Some of the largest electric utilities that have publicly announced near- and long-term GHG reduction commitments, many with emission reduction targets of at least 80 percent (relative to 2005 levels unless otherwise noted), include:

- *Xcel Energy:* 80 percent reduction in CO_2 emissions by 2030 and 100 percent carbon-free by 2050. This includes a commitment to close or repower all remaining coal-fired EGUs by 2030.[134]
- *DTE Energy:* 65 percent reduction in CO_2 emissions by 2028, 90 percent reduction by 2040, and net-zero carbon emissions by 2050.[135]
- *Ameren Energy:* 60 percent reduction in CO_2 by 2030, 85 percent reduction by 2040, and net-zero carbon emissions by 2045.[136]
- *Consumers Energy:* 60 percent reduction in CO_2 by 2025 and net-zero carbon emissions by 2040. This includes the retirement of all coal-fired units by 2025.[137]
- *Southern Company:* 50 percent reduction in CO_2 by 2030 (relative to 2007 levels) and net-zero carbon emissions by 2050.[138]
- *Duke Energy:* 70 percent reduction in CO_2 by 2030 and net-zero carbon

[132] *West Virginia* v. *EPA,* 142 S. Ct. 2587, 2615 (2022).

[133] See Comments of Edison Electric Institute to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, Docket ID No. EPA–HQ–OAR–2022–0723, 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.'').

[134] Xcel Energy is based in Minnesota with operations in Colorado, Michigan, New Mexico, North Dakota, South Dakota, Texas, and Wisconsin. *2018 Integrated Resource Plan* at *https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/2018-SPS-NM-Integrated-Resource-Plan.pdf.*

[135] DTE Energy is based in Michigan. *Our Bold Goal for Michigan's Clean Energy Future* at *https://dtecleanenergy.com/.*

[136] Ameren is based in Illinois and Missouri. *2022 Integrated Resource Plan* at *https://www.ameren.com/missouri/company/environment-and-sustainability/integrated-resource-plan.*

[137] Consumers Energy is based in Michigan. *Integrated Resource Plan* at *https://s26.q4cdn.com/888045447/files/doc_presentations/2021/06/2021-Integrated-Resource-Plan.pdf.*

[138] Southern Company is based in Georgia with operations in Alabama and Mississippi. *https://www.southerncompany.com/sustainability/net-zero-and-environmental-priorities/net-zero-transition.html.*

emissions by 2050. All coal-fired units will retire by 2035.[139]

- *Minnesota Power (Allete Inc.):* 70 percent renewable energy by 2030, 80 percent reduction in CO_2 and coal-free by 2035, and 100 percent carbon-free by 2050.[140]
- *First Energy:* 30 percent reduction in CO_2 by 2030 (relative to 2019 levels) and net-zero carbon emissions by 2050.[141]
- *American Electric Power:* 80 percent reduction in CO_2 by 2030 and net-zero carbon emissions by 2045.[142]
- *Alliant Energy:* 50 percent reduction in CO_2 by 2030 and net-zero carbon emissions by 2050; will retire final coal-fired EGU by 2040.[143]
- *Tennessee Valley Authority:* 70 percent reduction in CO_2 by 2030, 80 percent reduction by 2035, and net-zero carbon emissions by 2050.[144]
- *NextEra Energy:* 70 percent reduction in CO_2 by 2025, 82 percent reduction by 2030, 87 percent reduction by 2035, 94 percent reduction by 2040, and carbon-free by 2045.[145]

The geographic footprint of zero or net-zero carbon commitments made by utilities, their parent companies, or in response to a State clean energy requirement, covers portions of 47 states and includes 75 percent of U.S. customer accounts.[146] These statements are often made as part of long-term planning processes with considerable stakeholder involvement, including regulators.

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. These actions include commitments that require utilities to expand renewable and clean energy production through the adoption of renewable portfolio standards (RPS) and clean energy standards (CES), as well as other measures tailored to decarbonize State power systems enacted in specific legislation.

Twenty-nine states and the District of Columbia have enforceable RPS.[147] RPS 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. Fifteen states have RPS targets that are at or well above 50 percent. Eight of these states—California, Illinois, Massachusetts, Maryland, Minnesota, New Jersey, Nevada, and Oregon—have targets ranging from 50 percent to just below 70 percent. Four states—Maine, New Mexico, New York, and Vermont—have RPS targets greater than or equal to 70 percent but below 100 percent, and three states—Hawaii, Rhode Island, and Virginia plus the District of Columbia—have 100 percent RPS requirements. Most of these ambitious targets fall during the next decade. Ten states and the District of Columbia have final targets that mature between 2025 and 2033, while the remaining five states impose peak requirements between 2040 and 2050. Resources that are eligible under an RPS vary by State and are determined by the State's existing energy production and possibility for renewable energy development. For example, Colorado's RPS includes a range of resources such as solar, wind, emissions-neutral coal mine methane and other sources as qualifying renewable energy sources. Hawaii's includes, but is not limited to, solar, wind, and energy produced from falling water, ocean water, waves, and water currents. RPS in some other states include landfill gas, animal wastes, CHP, and energy efficiency.[148]

States are also shifting their generating fleets away from fossil fuel generating resources through the adoption of CES. A CES requires 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. Twenty-one states have adopted some form of clean energy requirement or goal with 17 of those states setting 100 percent targets. In nearly all cases, the CES applies in addition to the State's other RPS requirements. Seven states, including California, Colorado, Minnesota, New York, Washington, Oregon, and Arizona, have a zero or net-zero carbon emissions requirement with most target dates falling in 2040, 2045, or 2050. Two states—New Mexico and Massachusetts—have 80 percent clean energy requirements that must be met in 2045 and 2050, respectively. Ten additional states, including Connecticut, New Jersey, Nevada, Wisconsin, Illinois, Maine, North Carolina, Nebraska, Louisiana, and Michigan, have 100 percent clean energy goals with target dates falling in either 2040 or 2050. Like an RPS, CES resource eligibility can vary from State to State. One key difference between an RPS and a CES is the extent to which a CES can allow for resources like nuclear and CCS-enabled coal and natural gas, which are not renewable but have low or zero direct GHG emission attributes that make them CES eligible.

In addition, states across the U.S. have announced specific legislation aimed at reducing GHG emissions. In California, Senate Bill 32, passed in 2016, was a landmark legislation that requires California to reduce its economy-wide GHG emissions to 1990 levels by 2020, 40 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050. Senate Bill 100, passed in 2018, requires California to procure 60 percent of all electricity from renewable sources by 2030 and plan for 100 percent from carbon-free sources by 2045. Senate Bills 605 and 1383, passed in 2016, require a reduction in emissions of short-lived climate pollutants like methane by 40 to 50 percent below 2013 levels by 2030.[149] Achieving California's established goal

[139] Duke Energy is based in North Carolina with operations in South Carolina, Florida, Indiana, Ohio, and Kentucky. *NC IRP Fact Sheet* at *https://p-scapi.duke-energy.com/-/media/pdfs/our-company/202296-nc-irp-fact-sheet.pdf.*

[140] Allete Energy is based in Minnesota with operations in Wisconsin and North Dakota. *Integrated Resource Plan* at: *https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b70795F77-0000-C41E-A71C-FD089119967C%7d&documentTitle=20212-170583-01.*

[141] First Energy is based in Ohio with operations in Pennsylvania, West Virginia, and New Jersey. *https://www.firstenergycorp.com/content/dam/environmental/files/climate-strategy.pdf.*

[142] American Electric Power (AEP) is based in Ohio with operations in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. *Clean Energy Future* at *https://www.aep.com/about/ourstory/cleanenergy.*

[143] Alliant Energy has operations in Iowa and Wisconsin. See *Our Sustainable Energy Plan* at *https://www.alliantenergy.com/cleanenergy/ourenergyvision/poweringwhatsnext/sustainableenergyplan.*

[144] Tennessee Valley Authority (TVA) is based in Tennessee with operations in Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. See *https://www.tva.com/newsroom/press-releases/tva-charts-path-to-clean-energy-future.*

[145] NextEra Energy. See *https://newsroom.nexteraenergy.com/2022-06-14-NextEra-Energy-sets-industry-leading-Real-Zero-TM-goal-to-eliminate-carbon-emissions-from-its-operations,-leverage-low-cost-renewables-to-drive-energy-affordability-for-customers.*

[146] Smart Electric Power Alliance Utility Carbon Tracker. See *https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.* Accessed January 12, 2023.

[147] DSIRE, Renewable Portfolio Standards and Clean Energy Standards (2022). *https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2022/11/RPS-CES-Nov2022.pdf.*

[148] NCSL (2021). *State Renewable Portfolio Standards and Goals. https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.*

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

of carbon-free electricity by 2045 requires emissions to be balanced by carbon sequestration, capture, or other technologies. Senate Bill 905, passed in 2022, requires the California Air Resources Board to establish programs for permitting CCS projects.[150] Senate Bill 905, also passed in 2022, prevents the use of captured CO_2 for enhanced oil recovery within California.

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.[151]

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.[152]

In addition to the prevalence of State RPS and CES programs outlined above, several states developed regulatory programs to retain nuclear power plants to preserve the significant amount of zero-emission output the plants provide, especially as many nuclear plants face downward economic pressures resulting from ultra-low natural gas spot prices combined with increasing NGCC capacity. Between 2016 and 2021, New York, New Jersey, Connecticut, and Illinois took action to retain their nuclear power stations by providing State-level financial incentives. Retention of nuclear power plants is another strategy that some states have used to ensure an increasing market share for zero-emission electricity generation. As discussed earlier, the IRA included a zero-emission nuclear power production credit in section 13105, also referred to as IRC section 45U.[153]

In the past two years, State actions have generally increased their decarbonization ambitions. For example, legislation in Illinois and North Carolina requires a transition away from GHG-emitting generation. Illinois' Climate and Equitable Jobs Act, which became law on September 25, 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.[154] On October 13, 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%) 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.'' [155]

1. 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 Modeling Platform v6 Using the Integrated Planning Model post-IRA 2022 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.[156]

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 [157] [158] and participated in public events exploring modeling assumptions for the IRA.[159] The EPA plans to continue collaborating with stakeholders, conducting external engagements, and using information gathered to refine modeling of the IRA. As such, the EPA is soliciting comment on power sector modeling of the IRA, including the assumptions and potential impacts, including assumptions about growth in electric demand, rates at which renewable generation can be built, and cost and performance assumptions about all relevant technologies, including carbon capture, renewables, energy storage and other generation technologies.

While much of the discussion below focuses on the EPA's post-IRA 2022 reference case, many other analyses show similar trends,[160] 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. Projections for Coal-Fired Generation

In the post-IRA 2022 reference case, coal-fired steam EGU capacity is projected to fall from 210 GW in 2021 [161] to 44 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 [162] to 120 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 41 percent in 2021 to 15 percent in 2035. By 2050, coal-fired steam generating unit capacity is projected to diminish further, with only 10 GW, or less than 5 percent of 2021

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

[151] New York State. *Our Progress. https://climate.ny.gov/Our-Progress.*

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

[153] *http://uscode.house.gov/view.xhtml?req=(title:26%20section:45U%20edition:prelim).*

[154] 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.*

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

[156] U.S. Environmental Protection Agency. *Post-IRA 2022 Reference Case EPA's Power Sector Modeling Platform v6 Using IPM.* April 2023. *https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case.*

[157] Bistline, *et al.* (2023). ''Emissions and Energy System Impacts of the Inflation Reduction Act of 2022,'' Under Review.

[158] Bistline, *et al.* (2023). ''Power Sector Impacts of the Inflation Reduction Act of 2022,'' In Preparation.

[159] 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/.*

[160] 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,'' In Preparation.

[161] U.S. Energy Information Administration (EIA), Electric Power Annual, table 4.3. November 2022. *https://www.eia.gov/electricity/annual/.*

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

capacity (and approximately 3 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.

In 2020, there was a total of 1,439 million metric tons of CO_2 from the power sector with coal-fired sources contributing to over half of those emissions. In the post-IRA 2022 reference case, power sector related CO_2 emission are projected to fall to 608 million metric tons by 2035, of which 8 percent is projected to come from coal-fired sources in 2035.

2. Projections for Natural Gas-Fired Generation

As described in the post-IRA 2022 reference case, natural gas-fired capacity is expected to continue to buildout during the next decade with 61 GW of new capacity projected to come online by 2035 and 309 GW of new capacity by 2050. By 2035, the new natural gas capacity is comprised of 24 GW of simple cycle combustion turbines and 37 GW of combined cycle combustion turbines. By 2050, most of the incremental new capacity is projected to come just from simple cycle combustion turbines. This also represents a higher rate of new simple cycle combustion 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 [163] to 1,402 thousand GWh by 2035. Power sector related CO_2 emissions from natural gas-fired EGUs were 615 million metric tons in 2021.[164] By 2035, emission levels are projected to reach 527 million metric tons, 93 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 64 percent, but by 2035, capacity factor projections fall to 50 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 simple cycle combustion 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 continued growth in natural gas-fired capacity include anticipated sustained lower fuel costs and the greater efficiency and flexibility offered by combustion turbines. Simple cycle combustion turbines operate at lower efficiencies but offer fast startup times to meet peaking load demands. In addition, combustion turbines, along with energy storage technologies, 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 natural gas-fired generation and the overall utilization of natural gas-fired capacity is expected to decline.

3. Projections for Renewable Generation

The EIA's *Short-Term Energy Outlook* (STEO) suggests that the U.S. will continue its expansion of wind and solar renewable capacity with most of the growth in electricity capacity additions in the next 2 years to come from renewable energy sources.[165] The EIA projects utility-scale solar capacity to grow by approximately 29 GW in 2023 and by 35 GW in 2024 wind generating capacity to grow by 7 GW in 2023 and by 7.5 GW in 2024. These increases in new renewable capacity will continue to reduce the demand for fossil fuel-fired generation.

In the post-IRA 2022 reference case projections, shows that this short-term trend in renewable capacity is expected to continue. Non-hydroelectric utility-scale renewable capacity is projected to increase from 209 GW in 2021 to 668 GW by 2035 and then to 1,293 GW by 2050. This capacity growth is comprised mostly of wind and solar. The post-IRA 2022 reference case shows projections of 399 GW of wind capacity by 2035 and 748 GW by 2050. Utility-scale solar capacity has a similar trajectory with 263 GW by 2035 and 539 GW by 2050 and small-scale or distributed solar capacity (*e.g.,* rooftop solar) similarly increases from 33 GW in 2021 to 198 GW in 2050.[166] In total, non-hydroelectric utility-scale renewable generation is projected to produce 45 percent of electricity generation by 2035 in the post-IRA 2022 reference case.

4. Projections for Energy Storage

According to EIA, the capacity of battery energy storage is expected to increase by 10 times between 2019 and 2023, of which 6 GW of battery storage capacity is planned to be co-located with solar generation.[167] The benefit of paring energy storage systems with solar capacity deployment is that the batteries can recharge throughout the middle of the day when surplus energy is available. Then this stored energy can be discharged during peak hours, supporting grid reliability and potentially displacing higher emitting generation. This also reduces curtailment of renewable energy when generation exceeds demand.

The build out of energy storage is projected to continue in the long-term, enabling the integration of renewable technologies with lower emission consequences. The post-IRA 2022 reference case shows projections of 97 GW of energy storage to be available on the grid by 2035 and 152 GW by 2050.

5. Projections for Nuclear Energy

The post-IRA 2022 reference case shows a steady decline in nuclear generating capacity, dropping from 96 GW in 2021 to 84 GW or by 12 percent by 2035. In the short-term, capacity reductions are expected to be delayed in part due to programs passed as part of the IIJA and IRA. These acts, along with several State programs, support the continued use of existing nuclear facilities by providing payments that

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

[164] 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.*

[165] U.S. Energy Information Administration (EIA). *Short-Term Energy Outlook,* March 2023. *https://www.eia.gov/outlooks/steo/.*

[166] U.S. Energy Information Administration (EIA), Electric Power Annual, table 4.3. November 2022. *https://www.eia.gov/electricity/annual/.*

[167] U.S. Energy Information Administration (EIA). Preliminary Monthly Electric Generator Inventory, December 2020 Form EIA–860M. *https://www.eia.gov/analysis/studies/electricity/batterstorage/.*

will likely keep reactors in affected regions profitable for the next 5–10 years.[168] [169] After 2035, the EPA projects nuclear capacity retirements to occur as EGUs begin to age out of operation, and by 2050, the nuclear fleet is projected to reduce by more than half, to 45 GW. However, breakthrough technologies like small modular reactors, if successful, could result in higher levels of nuclear capacity than discussed here. For example, output from advanced nuclear generation could range from negligible to as high as 3,600 terawatt-hours per year by 2050.[170]

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 proposed 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.

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 emissions of air pollutants from new sources (including modified and reconstructed sources) in the source category. Under CAA section 111(a)(2), a ''new source'' is defined 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.

The standards of performance for new sources are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to the sources subject to them.

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 nonair 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,* 142 S. Ct. 2587, 2601 (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,* 142 S. Ct. at 2601.

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. If a State elects not to submit a plan or submits a plan that

[168] ''Constellation Making Major Investments in Two Illinois Nuclear Plants to Increase Clean Energy Output.'' Constellation Energy Corporation. February 21, 2023. *https://www.constellationenergy.com/newsroom/2023/Constellation-Making-Major-Investment-in-Two-Illinois-Nuclear-Plants-to-Increase-Clean-Energy-Output.html.*

[169] Singer, S. (February 22, 2023). *PSEG to consider nuclear plant investments, capitalizing on the IRA's production tax credits, CEO says.* Utility Dive. *https://www.utilitydive.com/news/pseg-ira-nuclear-production-tax-credits/643221/.*

[170] ''Advancing Nuclear Energy Evaluating Deployment, Investment, and Impact in America's Clean Energy Future'' Breakthrough Institute, July 6, 2022.

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 59276, 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'').

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. These standards remain 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 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.

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 while the Agency reviews the rule and considers whether to propose revisions to it.

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. The EPA is not reopening or soliciting 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 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. ''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; 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. The EPA has not taken further action on this proposed rule.[171]

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 [S]tate, 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), and the D.C. Circuit held the litigation in abeyance, and ultimately dismissed it, as the EPA reassessed its position. *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.[172]

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).

The EPA also stated that, under the ACE Rule, compliance measures that the State plans could authorize the sources to implement ''should correspond with the approach used to set the standard in the first place,'' (84 FR 32556; July 8, 2019), and therefore must ''apply at and to an individual source and reduce emissions from that source.'' See 84 FR 32555–56 (July 8, 2019). The EPA concluded that various measures besides generation shifting—including averaging (*i.e.,* allowing multiple sources to average their emissions to meet an emission-reduction goal), and trading (*i.e.,* allowing sources to exchange emission credits or allowances)—did not meet that requirement. The EPA therefore barred states from using such measures in their plans. See 84 FR 32556 (July 8, 2019).

[171] 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).

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

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 explained that contrary to the ACE Rule, the above-noted requirements in CAA section 111 that each State must establish a standard of performance ''for'' any existing ''building . . . [or] facility,'' mean that the State must establish standards applicable to each regulated stationary source; and the requirements that the degree of emission limitation must be achievable through the ''application'' of the BSER could be read to mean that the sources must be able to apply the system to reduce emissions across the source category. None of these requirements, the court further explained, can be read to mandate that the BSER is limited to some measure that each source can apply to its own facility to reduce its own emissions in a specified amount. 985 F.3d at 944–51. The court likewise rejected the view that the CPP's use of generation-shifting implicated a ''major question'' requiring unambiguous authorization by Congress. 985 F.3d at 958–68.

Having rejected the CPP Repeal Rule's view, also reflected in the ACE Rule, that CAA section 111 unambiguously requires that the BSER be ''one that can be applied to and at the individual source,'' the court also ''reject[ed] the ACE Rule's exclusion from [CAA section 111(d)] of compliance measures'' that do not meet that requirement. 985 F.3d at 957. Thus, the court held that CAA section 111 does not preclude states from allowing trading or averaging. The court explained that the ACE Rule's premise for its view that compliance measures are limited to measures applied at and to an individual source is that BSER measures are so limited, but the court further stated that this premise was invalid. The court added that in any event, CAA section 111(d) says nothing about the type of compliance measures states may adopt, regardless of what the EPA identifies as the BSER. *Id.* at 957–58.

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 numerous other challenges to the ACE Rule, including the arguments by Petitioners that the heat rate improvement BSER was inadequate because of the limited amount 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. In its motion, the EPA explained that the CPP should remain repealed because the deadline for states to submit their plans under the CPP had long since passed. In addition, and most importantly, because of ongoing changes in electricity generation—in particular, retirements of coal-fired electricity generation—the emissions reductions that the CPP was projected to achieve had already been achieved by 2021. *American Lung Assn* v. *EPA,* No. 19–1140, Respondents' Motion for a Partial Stay of Issuance of the Mandate (February 12, 2021). 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

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,* 142 S. Ct. 2587 (2022). The Supreme Court made clear 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. However, the Supreme Court invalidated the CPP's generation-shifting BSER under the major questions doctrine. 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 also emphasized that the adoption of generation shifting was based on a ''very different kind of policy judgment [than prior CAA section 111 rules]: that it would be 'best' if coal made up a much smaller share of national electricity generation.'' *Id.* at 2612. 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. Beyond highlighting the novelty of generation shifting, 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). The Court explained that ''[a]t bottom, the [CPP] essentially adopted a cap-and-trade scheme, or set of state cap-and-trade schemes, for carbon,'' and that Congress ''has consistently rejected proposals to amend the Clean Air Act to create such a program.'' *Id.*

For these and related reasons, the Court viewed the CPP as raising a major question, and therefore, under the major questions doctrine, required ''clear congressional authorization'' as a basis. *Id.* (internal quotation marks and citation omitted). The EPA had defended generation shifting as qualifying as a ''system of emission reduction'' under CAA section 111(a)(1), but the Court found that the term ''system'' is ''a vague statutory grant [that] is not close to the sort of clear authorization required'' under the doctrine, *id.,* and, on that basis, invalidated the CPP.

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 (''We have no occasion to decide whether the statutory phrase 'system of emission reduction' refers *exclusively* to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as the BSER.'' (emphasis in original)). Nor did the Court address the scope of the States' compliance flexibilities.

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.

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.'' The D.C. Circuit has stated that whether and how to subcategorize is a decision for which the EPA is entitled to a ''high degree of deference'' because it entails ''scientific judgement.'' *Lignite Energy Council* v. *EPA,* 198 F3d 930, 933 (D.C. Cir. 1999); *see Sierra Cub,* v. *Costle,* 657 F.2d 298, 318–19 (D.C. Cir. 1981).

Although CAA section 111(d)(1) does not by its terms address subcategorization, the EPA interprets 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) provides a broad grant of authority to the EPA, directing it 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 the breadth of authority that CAA section 111(d) grants the EPA:

> Although the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in 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, 142 S. Ct. at 2601–02 (citations omitted). That this broad authority under CAA section 111(d) includes subcategorization follows from the fact that these provisions authorize the EPA to determine the BSER. Subcategorizing is a mechanism for determining different controls to be the BSER for different sets of sources. This is clear from CAA section 111(b)(2) itself, which authorizes the EPA to subcategorize new sources ''for the purpose of establishing . . . standards.'' In addition, 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 costs of control, physical limitations, geographical location, or [based on] similar factors.'' [173] In promulgating this provision, the EPA made clear the purpose of subcategorization is to tailor the BSER for different sets of sources:

> EPA's emission guidelines will reflect subcategorization within source categories where appropriate, taking 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. Thus, 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 when they have characteristics that are relevant to the controls they can apply to reduce their emissions. 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.* That is, subcategorization is appropriate for a set of sources that have qualities in common that are relevant for determining what controls are appropriate for those sources. And where the qualities in common are *not* relevant for determining what controls are appropriate, subcategorization is not appropriate. This view is consistent with the D.C. Circuit's interpretation of CAA section 112(d)(1), which is a subcategorization provision that is substantially similar to CAA section 111(b)(2). In *NRDC* v. *EPA,* 489 F.3d 1364, 1375–76 (D.C. Cir. 2007), the court upheld the EPA's decision under CAA section 112(d)(1) *not* to subcategorize sources subject to control requirements under CAA section 112(d)(3), known as the maximum achievable control technology (MACT) floor, on the basis of

[173] 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.

costs. That was because the EPA is not authorized to consider costs in setting the MACT floor.[174]

The EPA has developed subcategories in numerous rulemakings under CAA section 111 since it began promulgating them in 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 Cub,* 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 subcategories turbines on the basis of whether they are located in, for example, a continental area, a noncontinental area, the part of Alaska north of the Arctic Circle, and the rest of Alaska), *see also Sierra Club* v. *Costle,* 657 F.2d 298, 330 (D.C. Cir. 1981) (stating that the EPA could create different subcategories for new sources in the Eastern and Western U.S. for requirements that depend on water-intensive controls). As these references indicate, 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. It should also be noted that in some instances, the EPA has declined to subcategorize. *Lignite Energy Council,* 198 F.3d at 933 (upholding EPA decision not to subcategorize utility boilers for purposes of NO_X NSPS on grounds that the decision was not arbitrary and capricious).

Regardless of whether the EPA subcategorizes within a source category for purposes of determining the BSER and the emission performance level for the emission guideline, 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.

D.C. Circuit Order To Reinstate 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 *West Virginia* decision, 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 Ass'n* remain valid. 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 valid. 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.

3. 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,[175] 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 . . . 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

[174] *See Chem. Mfrs. Ass'n* v. *NRDC,* 470 U.S. 116, 131 (1985) (Court interprets similar subcategorization provision under the Clean Water Act to grant the EPA broad discretion).

[175] *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,* 142 S. Ct. 2587 (2022). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

pollution'' [176] reduced and the role of ''technological innovation.'' [177] The determination of the ''best'' system entails weighing the various factors against each other, and the D.C. Circuit has emphasized that the EPA has discretion in weighing the factors.[178 179]

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 reductions, costs, any nonair health and environmental impacts, and energy requirements. As discussed below, for each of numerous subcategories, the EPA followed this approach to propose the BSER on the basis that the identified costs are reasonable and that the proposed BSER is rational in light of the statutory factors and other impacts, 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.[180] For a CAA section 111(b) rule, we determine 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 proposed these determinations in association with each of the proposed 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'.'' 142 S. Ct. at 2611 (quoting the Clean Power Plan).[181] 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 reduction'' to serve as the basis for an ''achievable'' emission limitation, is that the Administrator must determine that the system is ''adequately demonstrated.'' This means, according to the D.C. Circuit, that the system is ''one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' [182] It does not mean that the system ''must be in actual routine use somewhere.'' [183] Rather, the court has said, ''[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.'' [184] Similarly, the EPA may ''hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.'' [185] Ultimately, the analysis ''is partially dependent on 'lead time,' '' that is, ''the time in which the technology will have to be available.'' [186] The caselaw is clear that the EPA may treat a set of control measures as ''adequately demonstrated'' regardless of whether the measures are in widespread commercial use. For example, the D.C. Circuit upheld the EPA's determination that selective catalytic reduction (SCR) was adequately demonstrated to reduce NO_X emissions from coal-fired industrial boilers, even though it was a ''new technology.'' The court explained that ''section 111 'looks toward what may fairly be projected for the regulated future, rather than the state of the art at present.' '' *Lignite Energy Council,* 198 F.3d at 934 (citing *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973)). The Court added that the EPA may determine that control measures are ''adequately demonstrated'' through a ''reasonable

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

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

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

[179] Although CAA section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination, the D.C. Circuit's case law may be read to treat them as part of the ''best'' determination. *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''). Nevertheless, it does not appear that those two approaches would lead to different outcomes. *See, e.g., Lignite Energy Council,* 198 F.3d at 933 (rejecting challenge to the EPA's cost assessment of the ''best demonstrated system''). Regardless of whether the factors are part of the ''adequately demonstrated'' determination or the ''best'' determination, our analysis and outcome would be the same.

[180] See, *e.g.,* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews (77 FR 49490, 49494; August 16, 2012) (describing the three-step analysis in setting a standard of performance).

[181] 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 proposed to reject that interpretation as too narrow. *See* ''Implementing Regulations under 40 CFR part 60 Subpart Ba Adoption and Submittal of State Plans for Designated Facilities: Proposed Rule,'' 87 FR 79176, 79208 (December 23, 2022).

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

[183] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted) (discussing the Senate and House bills and reports from which the language in CAA section 111 grew).

[184] Ibid.

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

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

extrapolation of [the control measures'] performance in other industries.'' Id.

The D.C. Circuit's view that the EPA may determine a ''system of emission reduction'' to be ''adequately demonstrated'' if the EPA reasonably projects that it will be available by a future date certain, is well-grounded in the purposes of CAA section 111 to reduce dangerous air pollutants. This view recognizes that 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, and begin to operate them. In some instances, the control technology may be available, but the installation may be a multi-year process. For example, an existing coal-fired steam generating unit may require several years to plan, design, and install a Flue Gas Desulfurization (FGD) wet scrubber for the control of sulfur dioxide (SO_2) emissions. Under these circumstances, common sense dictates that the EPA may promulgate a rulemaking that imposes a standard on the sources, but establishes the date for compliance as a date-certain in the future, consistent with the period of time the source needs to install and start operating the control equipment. In other circumstances, a system of emission reduction may be well-recognized as effective in controlling pollutants emitted by a large source category, but manufacturers may require a predictable amount of time to manufacture enough control equipment to cover the source category. In still other circumstances, the infrastructure needed to support the system so that it will cover sources across the category—whether physical infrastructure such as pipelines or human infrastructure such as skilled labor to install the equipment—may require a predictable amount of time to build out or develop in sufficient quantity to achieve such coverage. In all of these circumstances, adopting requirements under CAA section 111 at the time that the EPA is able to reasonably project the future deployment of the system of emission reduction, and establishing the date of compliance as a date-certain in the future, serves the statutory purposes of protecting against dangerous air pollution by ensuring that sources take action to control their emissions as soon as practicable. It should also be noted that because pollution control invariably entails additional cost, in some cases, the EPA's promulgation of regulatory requirements may be an essential trigger for the sometimes lengthy process of implementing pollution controls. In these cases, delaying the promulgation of the regulatory requirements until the pollution controls can be immediately deployed would be futile.

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.'' By its terms, this provision makes clear that the cost that the EPA must take into account is the cost to the affected source of the system of emission reduction. Although the Clean Air Act does not describe how the EPA is to account for costs, the D.C. Circuit has formulated the cost standard in various ways.[187] It has stated that the EPA may not adopt a standard the cost of which would be ''exorbitant,''[188] ''greater than the industry could bear and survive,''[189] ''excessive,''[190] or ''unreasonable.''[191] These formulations appear to be synonymous, and for convenience, in these rulemakings, we are treating them as synonymous with reasonableness as well, so that a control technology may be considered the ''best system of emission reduction . . . adequately demonstrated'' if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable.[192]

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.''[193] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973);[194] *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. 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 emissions 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, a metric that determines the dollar increase in the cost of a megawatt hour of electricity generated by the affected sources due to the emission controls, shows the cost of controls relative to the output of electricity. *See* section VII.F.3.b.iii(B)(5) of this preamble, which discusses $/MWh costs of the March 15, 2023 Good Neighbor Plan for the 2015 Ozone NAAQS and the Cross-State Air Pollution Rule (CSAPR) 76 FR 48208 (August 8, 2011). This metric facilitates comparing costs across regulations and pollutants. In this proposal, as explained herein, the EPA looks at both of these metrics to assess the cost reasonableness of the proposed requirements.

[187] 79 FR 1430, 1464 (January 8, 2014).

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

[189] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

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

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

[192] 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 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.

[193] 1977 House Committee Report at 184.

[194] The costs for these standards were described in the rulemakings. See 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).

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.[195] 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.[196]

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. . . .[197]

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 D.C. Circuit has made clear that the EPA has broad discretion. Specifically, 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,'' [198] 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.[199] 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.[200]

See AEP v. *Connecticut,* 564 U.S. 410, 427 (2011) (under CAA section 111, ''The 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)).

Moreover, the D.C. Circuit has also read ''best'' to authorize 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 298, 326, 346–47 (D.C. Cir. 1981), the court added that the EPA must consider the amount of emission reductions and technology advancement in determining BSER.

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

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

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

[197] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583–33584; June 11, 1979).

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

[199] *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).

[200] *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.'').

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.[201] 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 D.C. Circuit has stated that 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'').[202] 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 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''.[203] In addition, the court's interpretation finds support in the legislative history.[204] 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); [205] (2) the expanded use of the best demonstrated technology; [206] and (3) the development of emerging technology.[207] 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. According to the D.C. Circuit, 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.[208] 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.'' [209] 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.'' [210] 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.'' [211]

Although the D.C. Circuit 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 as between new and existing sources due to, for example, higher costs

[201] 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 74702, 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.

[202] *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.''

[203] *Sierra Club* v. *Costle,* 657 F.2d at 346 (''Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair 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.'').

[204] 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'').

[205] *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'').

[206] 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'').

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

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

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

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

[211] *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).

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,* 142 S. Ct. 2587, 2601–02 (2022).[212]

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 more or 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.

4. 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 CAA section 110-like procedure 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 implement and enforce those 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 BSER for the existing sources and, based on the BSER, to establish emission guidelines that identify the minimum amount of emission limitation that a State, in its State plan, must impose on its existing sources through standards of performance. Consistent with these CAA requirements, the EPA's regulations require that the EPA's 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 impact and energy requirements) the Administrator has determined has been adequately demonstrated from designated facilities.[213]

Following the EPA's promulgation of emission guidelines, each State must determine the standards of performance for its existing sources, which the EPA's regulations call ''designated facilities.'' [214] While the EPA specifies in emission guidelines the degree of emission limitation achievable through application of the best system of emission reduction, which it may express as a presumptive standard of performance, a State retains discretion in applying such a presumptive standard of performance to any particular designated facility. CAA section 111(d)(1) requires the EPA's regulations to ''permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life the . . . source . . . .'' Consistent with this statutory direction, the EPA's regulations provide requirements for States that wish to apply standards of performance that deviate from an emission guideline. In December 2022, the EPA proposed to clarify these requirements, including the three circumstances under which States can invoke a particular source's remaining useful life and other factors (RULOF), to apply a less stringent standard of performance. These proposed clarifications provided:

> The State may apply a standard of performance to a particular source that is less stringent than otherwise required by an applicable emission guideline, taking into consideration remaining useful life and other factors, provided that the State demonstrates with respect to each such facility (or class of such facilities) that it cannot reasonably apply the best system of emission reduction to achieve the degree of emission limitation determined by the EPA, based on:
>
> (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
>
> (2) Physical impossibility or technical infeasibility of installing necessary control equipment; or
>
> (3) Other circumstances specific to the facilities (or class of facilities) that are fundamentally different from the information considered in the determination of the best system of emission reduction in the emission guidelines.

87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed 40 CFR 60.24a(e)).[215] In addition, under CAA sections 111(d) and 116, the State is authorized to establish a standard of performance for any particular source that is more stringent than the presumptive standards contained in the EPA's emission guidelines.[216] Thus, for any particular source, a State may apply a standard of performance that is either more stringent or less stringent than the presumptive standards of performance in the emission guidelines. The State must include the standards of performance in their State plans and submit the plans to the EPA for review.[217] Under CAA section 111(d)(2)(A), the EPA approves State plans that are determined to be ''satisfactory.''

IV. Stakeholder Engagement

Prior to proposing these actions, the EPA conducted outreach to a broad range of stakeholders. The EPA also opened a non-regulatory pre-proposal docket to solicit public input on the Agency's efforts to reduce GHG emissions from new and existing EGUs.[218] For additional details on stakeholder engagement, see the memorandum in the docket titled *Stakeholder Outreach.*

The EPA conducted two rounds of outreach to gather input for these proposals. In the first round of outreach, in early 2022, the EPA sought input in a variety of formats and settings from States, Tribal nations, and a broad range

[212] 40 CFR 60.21(e), 60.21a(e).

[213] 40 CFR 60.21a(e).

[214] 40 CFR 60.21a(b), 60.24a(b).

[215] The EPA intends to finalize the December 2022 proposed revisions to the CAA section 111 implementation regulations in 40 CFR part 60, subpart Ba, including any changes made in response to public comments, prior to promulgating these emission guidelines. Thus, 40 CFR part 60, subpart Ba, as revised, would apply to these emission guidelines.

[216] 40 CFR 60.24a(f). The EPA's December 2022 proposed revisions to 40 CFR part 60, subpart Ba reflect its current interpretation that the EPA has the authority to review and approve plans that include standards of performance that are more stringent than the presumptive standards in the EPA's emission guidelines, thus making those more stringent requirements federally enforceable. 87 FR 79204 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed 40 CFR 60.24a(m), (n)). In addition, CAA section 116 authorizes the state to set standards of performance for all of its sources that, together, are more stringent than the EPA's emission guidelines.

[217] 40 CFR 60.23a. In January 2021, the D.C. Circuit Court of Appeals vacated the three-year deadline for state plan submissions of a final emission guideline in 40 CFR 60.23a(a)(1). The EPA's December 2022 proposed revisions to subpart Ba would revise 60.23a to, *inter alia,* provide for a fifteen-month submission deadline. 87 FR 79182 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed 40 CFR 60.23a(a)).

[218] Docket ID No. EPA–HQ–OAR–2022–0723.

of stakeholders on the state of the power sector and how the Agency's regulatory actions affect those trends. This outreach included State energy and environmental regulators; Tribal air regulators; power companies and trade associations representing investor-owned utilities, rural electric cooperatives, and municipal power agencies; environmental justice and community organizations; and labor, environmental, and public health organizations. A second round of outreach took place in August and September 2022, and focused on seeking input specific to this rulemaking. The EPA asked to hear perspectives, priorities, and feedback around five guiding questions, and encouraged public input to the nonregulatory docket (Docket ID No. EPA–HQ–OAR–2022–0723) on these questions as well.

The EPA also regularly interacts with other Federal agencies and departments whose activities intersect with the power sector, and in the course of developing these proposed rules the Agency conducted multiple discussions with these agencies to benefit from their expertise and to explore the potential interaction of these proposed rules with their independent missions and initiatives. Among other things, these discussions focused on the impacts of proposed investments in energy technology by the Department of Energy and Department of Treasury on the technical and economic analyses underlying this proposal. In addition, the EPA evaluated structures in these proposals to address reliability considerations with the Department of Energy.

VII. Proposed Requirements for New and Reconstructed Stationary Combustion Turbine EGUs and Rationale for Proposed Requirements

A. Overview

This section discusses and proposes requirements for stationary combustion turbine EGUs that commence construction or reconstruction after the date of publication of this proposed action. The EPA is proposing that those requirements will be codified in 40 CFR part 60, subpart TTTTa. The EPA explains in section VII.B the two basic turbine technologies in use in the power sector and covered by 40 CFR part 60, subpart TTTT, simple cycle turbines and combined cycle turbines. It further explains how these technologies are used in the three subcategories of low load turbines, intermediate load turbines, and base load turbines. Section VII.C provides an overview of how stationary combustion turbines have been previously regulated and how the EPA recently took comment on a proposed white paper on GHG mitigation options for stationary combustion turbines. Section VII.D discusses the EPA's decision to revisit the standards for turbines as part of the statutorily required 8-year review. Section VII.E discusses changes that the EPA is proposing in both applicability and subcategories in the new proposed 40 CFR part 60, subpart TTTTa as compared to those codified in 40 CFR part 60, subpart TTTT. Most notably, for natural gas-fired combustion turbines, the EPA is proposing three subcategories, a low load subcategory, an intermediate load subcategory, and a base load subcategory.

Section VII.F discusses the EPA's determination of the BSER for each of the subcategories of turbines. For low load combustion turbines, the EPA continues to believe that use of lower emitting fuels is the appropriate BSER. For intermediate load turbines, the EPA believes that both highly efficient generation and co-firing low-GHG hydrogen are appropriate components of the BSER, and that there will be enough low-GHG hydrogen at a reasonable price to supply the combustion turbines that would need to use it in 2032. For this reason, the EPA is proposing a two-component BSER for intermediate load combustion turbines, and a two-phase standard of performance. The first component of the BSER would be highly efficient generation (based on the performance of a highly efficient simple cycle turbine), with a corresponding first-phase standard of performance. The second component of the BSER is co-firing 30 percent (by volume) low-GHG hydrogen, along with continued use of highly efficient generation, with a corresponding second-phase standard of performance. The EPA is also soliciting comment on whether intermediate load combustion turbines should be subject to a more stringent third-phase standard based on higher levels of low-GHG hydrogen co-firing by 2038. Additionally, the EPA is soliciting comment on whether the electric sales threshold used to define intermediate and base load units should be reduced further.

For base load turbines, the EPA likewise believes that the BSER includes multiple components that correspond to a multi-phase standard of performance. This is appropriate based on consideration of the manufacturing and installation capabilities within the larger EGU category and other industries, and considerations of projected operation of combustion turbines in the future. For base load turbines, the EPA is proposing two BSER pathways with corresponding standards of performance that new and reconstructed stationary combustion turbines may take—one BSER pathway is based on the use of 90 percent CCS and a separate BSER pathway is based on co-firing low-GHG hydrogen. The EPA proposes that the first component of the BSER for both pathways is highly efficient generation (based on the performance of a highly efficient combined cycle unit) and the second component of the BSER is based on the use of either 90 percent CCS in 2035 or co-firing 30 percent (by volume) low-GHG hydrogen in 2032, along with continued use of highly efficient generation for both pathways. For base load turbines that are subject to a second phase standard of performance based on a highly efficient combined cycle unit co-firing 30 percent (by volume) low-GHG hydrogen, the EPA proposes that those units also meet a third phase component of the BSER based on the co-firing of 96 percent (by volume) low-GHG hydrogen by 2038. These two BSER pathways both offer significant opportunities to reduce GHG emissions even though they may be available on slightly different timescales. The EPA seeks comment specifically on the percentages of hydrogen co-firing and CO_2 capture, the dates that meet the statutory BSER criteria for each pathway, whether the Agency should finalize both pathways as separate subcategories with separate standards of performance, or whether it should finalize one pathway with the option of meeting the standard of performance using either system of emission reduction—*e.g.,* a single standard of 90 lb CO_2/MWh-gross based on the application of CCS with 90 percent capture, which could also be met by co-firing 96 percent low-GHG hydrogen.

For both intermediate load and 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 the publication date of this proposal. The EPA occasionally refers to these standards of performance as the phase-1, phase-2, or phase-3 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 multistage 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 to create shaft work. The shaft work drives an electric generator to produce electricity. Combustion turbines that recover their 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 a heat recovery steam generator (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 a second 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 proposal, 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 and quickly ramp to full load, and their ability to operate at partial loads while maintaining acceptable emission rates and efficiencies. The ability to start and quickly 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 capacity factors.

Highly efficient simple cycle turbines and 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. A developer's decision of whether to build a simple cycle combustion turbine or a combined cycle combustion turbine to serve intermediate load demand would be based on several factors related to the intended operation of the unit. These factors 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. While the owner/operator of an individual combustion turbine controls whether and how that unit will operate over time, they do not necessarily control the precise timing of dispatch for the unit 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 combustion turbines and fast-start combined cycle combustion turbines can fill this cycling role. While the ability to start and quickly ramp 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 combustion 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 firm dispatchable generating resources operate.[219] 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, firm dispatchable electric generating units are used to ensure the reliability of the electric grid. This requires technologies such as dispatchable power plants to start and stop and change load more frequently than was previously needed. Important characteristics of combustion turbines that provide firm backup capacity are the ability to start and stop quickly and the ability to quickly change loads. Natural gas-fired combustion turbines are much more flexible than coal-fired utility boilers in this regard and have played an important role in ensuring electric supply and demand are in balance during the past decade.

As discussed in section IV.F.2 of this preamble and in the accompanying RIA, the post-IRA 2022 reference case projects that natural gas-fired combustion turbines will continue to play an important role in meeting electricity demand. However, that role is projected to evolve as additional renewable and non-renewable low-GHG generation and energy storage technologies are added to the grid. Energy storage technologies can store energy during periods when generation from renewable resources is high relative to demand and provide electricity to the grid during other periods. This could reduce the need for fossil fuel-fired firm dispatchable power plants to start and stop as frequently. Consequently, in the future, natural gas-

[219] Dispatchable EGUs can be turned on and off and adjust the amount of power supplied to the electric grid based on the demand for electricity. Variable (sometimes referred to as intermittent) EGUs supply electricity based on external factors that are not controlled by the owner/operator of the EGU.

fired stationary combustion turbine EGUs may run at more stable operation and, thus, more efficiently (*i.e.,* at higher duty cycles and for longer periods of operation per start). The EPA is soliciting comment on whether this a likely scenario.

C. Overview of Regulation of Stationary Combustion Turbines for GHGs

As explained earlier in this preamble, the EPA originally regulated 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 that is 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 and 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.

On April 21, 2022, the EPA issued an informational draft white paper, titled *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units.*[220] The draft document included discussion of the basic types of available stationary combustion turbines as well as factors that influence GHG emission rates from these sources. The technology discussion in the draft white paper included information on an array of new and existing control technologies and potential reduction measures for GHG emissions. These reduction measures included: the GHG reduction potential of various efficiency improvements; technologies capable of firing or co-firing alternative fuels such as hydrogen; the ongoing advancement of CCS projects with NGCC units; and the co-location of technologies that do not emit onsite GHG emissions with EGUs, such as onsite renewables or short-duration energy storage.

The EPA provided an opportunity for the public to comment on this white paper to inform its approach to this proposed rulemaking. More than 30 groups or individuals provided public comments on the topics and technologies discussed in the draft white paper. Commenters included representatives from utilities, technology providers, trade associations, States, regulatory agencies, NGOs, and public health advocates. The information provided in the public comments was beneficial in enabling the EPA to review the current NSPS for new stationary combustion turbines and to develop the proposed revisions described in this preamble.

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 companies are building new fossil fuel-fired combustion turbines and plan to continue building additional capacity. Because the emissions from this capacity have the potential to be large and these units are likely to have long lives (25 years or more), the EPA believes it is important to consider options to reduce emissions from these new units. In addition, the EPA is aware of developments concerning the types of control measures that may be available to reduce GHG emissions from new stationary combustion turbines. Accordingly, the EPA is proceeding to review and is proposing updated NSPS for newly constructed and reconstructed fossil fuel-fired stationary combustion turbines.

E. Applicability Requirements and Subcategorization

This section describes the proposed amendments to the specific applicability criteria for non-fossil fuel-fired EGUs, industrial EGUs, CHP EGUs, and combustion turbines EGUs not connected to a natural gas pipeline. The EPA is also proposing certain changes to the applicability requirements for stationary combustion turbines affected by this proposal as compared to those for sources affected by the 2015 NSPS. The proposed changes are described below and include the elimination of the multi-fuel-fired subcategory, further binning non-base load combustion turbines into low and intermediate load subcategories, and lowering the electric sales 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 current 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 million British thermal units per hour (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).[221] 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 megawatt-hours (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)

[220] *https://www.epa.gov/stationary-sources-air-pollution/white-paper-available-and-emerging-technologies-reducing.*

[221] 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.

certain projects under development, as discussed below.

a. Revisions to 40 CFR Part 60, Subpart TTTT

The EPA is proposing to amend 40 CFR 60.5508 and 60.5509 to reflect that 40 CFR part 60, subpart TTTT will remain applicable to steam generating EGUs and IGCC units constructed after January 8, 2014 or reconstructed after June 18, 2014. The EPA is also proposing that stationary combustion turbines that commenced construction after January 8, 2014 or reconstruction after June 18, 2014 and before May 23, 2023 that meet the relevant applicability criteria would be subject to 40 CFR part 60, subpart TTTT. Upon promulgation of 40 CFR part 60, subpart TTTTa, stationary combustion turbines that commence construction or reconstruction after May 23, 2023 and meet the relevant applicability criteria will be subject to 40 CFR part 60, subpart TTTTa.

b. Revisions to 40 CFR Part 60, Subpart TTTT That Would Also Be Included in 40 CFR Part 60, Subpart TTTTa

The EPA is proposing 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 proposed amendments that would be 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 both (1) Be capable of combusting more than 50 percent non-fossil fuel and (2) be subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) 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 written, these solar thermal installations would not be 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 is proposing several amendments to align the applicability criteria with the original intent to cover only fossil fuel-fired EGUs. This would ensure that solar thermal EGUs with natural gas backup burners, like other types of non-fossil fuel-fired units in which most of their energy is derived from non-fossil fuel sources, are not subject to the requirements of 40 CFR part 60, subparts TTTT or TTTTa. Amending the applicability language to include heat input derived from non-combustion sources would allow these facilities to avoid the requirements of 40 CFR part 60, subparts 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 proposing to amend 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 would also be amended to include the heat input from non-combustion sources (*e.g.,* solar thermal).

The proposed amended non-fossil fuel applicability language changing ‘‘combusting’’ to ‘‘deriving’’ will ensure that 40 CFR part 60, subparts TTTT and TTTTa cover the fossil fuel-fired EGUs, properly understood, that the original rule was intended to cover, while minimizing unnecessary costs to EGUs fueled primarily by steam generated without combustion (*e.g.,* through the use of solar thermal). 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 is 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, subparts 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 might 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, subparts TTTT or TTTTa could discourage the development of environmentally beneficial projects.

To avoid these outcomes, the EPA is proposing to amend 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.[222] 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 with little if any additional emissions. Including these types of projects would result in regulatory burden without any

[222] 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.

associated environmental benefit and could discourage project development, 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 for determining applicability with both the new source CAA section 111(b) requirements and if 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 by 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 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 is proposing to amend 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 would 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 proposed revisions would simply 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 proposing the exemption to eliminate 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 and is relevant to both new and existing EGUs.[223] 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.[224] 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 are not able to readily determine whether they meet the applicability criteria and are therefore subject to the 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 and it is likely they do not meet the applicability criteria. 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 compliance burden, the EPA is proposing 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 would petition the Administrator in writing to use an alternate method to determine the design efficiency. The Administrator's discretion is intentionally left broad and could 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 is also proposing to change 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 would allow 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 proposed amendments that would only be incorporated into 40 CFR part 60, subpart TTTTa and would differ from the requirements in 40 CFR part 60, subpart TTTT.

i. Proposed Applicability

Section 111 of the CAA defines a new or modified source for purposes of a given NSPS as any stationary source

[223] While the EPA could specifically allow different methods to determine the design efficiency in the 111(d) existing source emission guidelines, the Agency is proposing to align the criteria for regulatory clarity.

[224] 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.

that commences construction or modification after the publication of the proposed regulation. Thus, any standards of performance the Agency finalizes as part of this rulemaking will apply to EGUs that commence construction or reconstruction after the date of this proposal. EGUs that commenced construction after the date of the proposal for the 2015 NSPS and by the date of this proposal 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.[225] 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.[226]

The EPA is proposing 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 million British thermal units per hour (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).[227] In addition, the EPA is proposing 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 is proposing to apply 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 is proposing for comparable units in the contiguous 48 States. However, new units in non-continental and non-contiguous areas may operate on small, isolated electric grids, may operate differently from units in the contiguous 48 States, and may have limited access to certain components of the proposed BSER due to their uniquely isolated geography or infrastructure. Therefore, the EPA is soliciting comment on whether combustion turbines in non-continental and non-contiguous areas should be subject to different requirements.

ii. Applicability to CHP Units

For 40 CFR part 60, subpart TTTT, owner/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 more traditional CHP units. For 40 CFR part 60, subpart TTTTa, the EPA is proposing 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.[228] 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 proposed approach in 40 CFR part 60, subpart TTTTa would set a 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 would eliminate 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 is proposing that for CHP units determining net electric sales, purchased power of the host facility would be determined based on the percentage of thermal power provided to the host facility by the specific CHP facility.

iii. Non-Natural Gas Stationary Combustion Turbines

There is currently an exemption in 40 CFR part 60, subpart TTTT for

[225] 40 CFR 60.2.

[226] 40 CFR 60.15(a).

[227] 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.

[228] For contractual reasons, many developers of CHP units sell all the generated electricity to the electricity distribution grid even though in actuality a significant portion of the generated electricity is used onsite. 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.

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 proposing requirements for new and reconstructed combustion turbines that are not capable of combusting natural gas. As described in the standards of performance section, the Agency is proposing that 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 would have to maintain the same efficiency compared to a natural gas-fired combustion turbine and comply with a standard of performance based on the identified BSER. Therefore, 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.

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 is proposing to determine are the BSER for each of the subcategories of new and reconstructed combustion turbines that commence construction after the date of this proposal, and explains its basis for proposing those controls, and not others, as the BSER. The controls that the EPA is evaluating include 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 is proposing the use of lower emitting fuels as the BSER. For the intermediate load subcategory, the EPA is proposing an approach under which the BSER is made up of two components that each represent a different set of controls, and that form the basis of standards of performance that apply in multiple phases. That is, affected facilities—which are facilities that commence construction or reconstruction after the date of this proposed rulemaking—must meet the first phase of the standard of performance, which is based on the application of the first component of the BSER, highly efficient generation, by the date the rule is finalized; and then meet the second and more stringent phase of the standard of performance, which is based on co-firing 30 percent (by volume) low-GHG hydrogen by 2032. The EPA is also soliciting comment on whether the intermediate load subcategory should apply a third component of BSER, which is co-firing 96 percent (by volume) low-GHG hydrogen by 2038. In addition, the EPA is also soliciting comment on whether the low load subcategory should apply the second component of BSER, which is co-firing 30 percent (by volume) low-GHG hydrogen by 2032. These latter components of BSER would also include the continued application of highly efficient generation.

For the base load subcategory, the EPA is also proposing a multi-component BSER and an associated multi-phase standard of performance. The first component of the BSER, as with intermediate load combustion turbines, is highly efficient generation. New base load combustion turbines would be required to meet a phase one standard of performance based on the application of the first component of the BSER upon initial startup of the source. Subsequently, EPA is proposing two technology pathways as potential BSER for base load combustion turbines, with corresponding standards of performance. The first technology pathway is based on 90 percent CCS, which base load combustion turbines may install and begin to operate to meet the standard of performance by 2035. The second technology pathway is based on co-firing low-GHG hydrogen, which EPA proposes base load combustion turbines may undertake in two steps—by co-firing 30 percent (by volume) low-GHG hydrogen to meet the second phase of the standard of performance by 2032 and, then by co-firing 96 percent (by volume) low-GHG hydrogen to meet the third phase of the standard of performance by 2038. Throughout, base load turbines, like intermediate load turbines, would remain subject to the BSER of highly efficient generation.

This approach reflects the EPA's view that the BSER for the intermediate load and base load subcategories should reflect the deeper reductions in GHG emissions that can be achieved by implementing CCS and co-firing low-GHG hydrogen but recognizes that building the infrastructure required to support widespread use of CCS and low-GHG hydrogen in the power sector will take place on a multi-year time scale. Accordingly, newly constructed or reconstructed facilities must be aware of their need to ramp toward more stringent phases of the standards, which reflect application of the more stringent controls in the BSER, either through use of co-firing a lower level of low-GHG hydrogen by 2032 and a higher level of low-GHG hydrogen by 2038 or through use of CCS by 2035. The EPA is also soliciting comment on the potential for an earlier compliance date for the second phase, for instance, 2030 for units co-firing 30 percent hydrogen by volume and 2032 for units installing CCS.

For the base load subcategory, the EPA is proposing both potential BSER pathways because it believes there may be more than one viable BSER pathway for base load combustion turbines to significantly reduce their CO_2 emissions and believes there is value in receiving comment on, and potentially finalizing, both BSER pathways to enable project developers to elect how they will reduce their CO_2 emissions on timeframes that make sense for each BSER pathway. The EPA recognizes that standards of performance are technology neutral and that if the EPA finalizes a standard based on application of CCS, units could meet that standard using co-firing of low-GHG hydrogen. The EPA solicits comment on whether co-firing of low-GHG hydrogen should be considered a compliance pathway for sources to meet a single standard of performance based on application of CCS rather than a separate BSER pathway. The EPA believes that there will 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, it will likely take a longer timeframe for those units to then ramp up to co-firing significant quantities of low-GHG hydrogen. Therefore, in this proposal, the EPA presents these pathways as separate subcategories, while soliciting comment on the option of finalizing a single standard of performance based on application of CCS.

Specifically, with respect to the first phase of the standards of performance, for both the intermediate load and base load subcategories, the EPA is proposing that the BSER is highly efficient generating technology—combined cycle technology for the base load subcategories and simple cycle technology for the intermediate load subcategory—as well as operating and maintaining it efficiently. 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. With respect to the second phase of the standards of performance, for base load combustion turbines adopting the CCS pathway, the BSER includes the use of 90 percent CCS. These sources would be required to meet standards of performance by 2035 that reflect application of both components of the BSER—highly efficient generation and CCS—and thus are more stringent. For base load combustion turbines adopting the low-GHG hydrogen co-firing pathway and for intermediate load combustion turbines, the BSER includes co-firing 30 percent by volume (12 percent by heat input) low-GHG hydrogen. These sources would be required to meet second phase standards of performance by 2032 that reflect the application of both components of the BSER—in this case, highly efficient generation and co-firing 30 percent (by volume) low-GHG hydrogen—and that are, again, more stringent. Finally, for base load combustion turbines adopting the low-GHG hydrogen co-firing pathway, the BSER also includes a third component—co-firing 96 percent (by volume) low-GHG hydrogen. These sources would be required to meet a third phase standard of performance equivalent to that for the affected sources applying CCS as a second component of the BSER. These sources would be required to meet that equivalent standard of performance reflecting the application of highly efficient generation and co-firing high levels of low-GHG hydrogen. Table 1 summarizes the proposed BSER for combustion turbine EGUs that commence construction or reconstruction after publication of this proposal. The EPA is also proposing standards of performance based on those BSER for each subcategory, as discussed in section VII.G.

TABLE 1—PROPOSED BSER FOR COMBUSTION TURBINE EGUS

Subcategory	Fuel	1st Component BSER	2nd Component BSER	3rd Component BSER
Low Load*	All Fuels	Lower emitting fuels	N/A	N/A
Intermediate Load	All Fuels	Highly Efficient Generation	30 percent (by volume) Low-GHG Hydrogen Co-firing by 2032.	N/A
Base Load	Sources adopting the CCS pathway.	Highly Efficient Generation	90 percent CCS by 2035	N/A
	Sources adopting the low-GHG hydrogen co-firing pathway.		30 percent (by volume) Low-GHG Hydrogen Co-firing by 2032.	96 percent (by volume) Low-GHG Hydrogen Co-firing by 2038

*The low load subcategory has a single-component BSER consisting of fuels that emit lower GHG emissions.

1. BSER for Low Load Subcategory

This section describes the proposed BSER for the low load (*i.e.,* peaking) subcategory, which is the use of lower emitting fuels. For this proposed rule, the Agency proposes to determine 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 in the standards of performance proposed in this action. As explained above, the EPA is proposing to narrow 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 turbines with higher electric sales would be placed in the proposed intermediate load subcategory and therefore be subject to a more stringent standards based on the more stringent component of the BSER. Unlike the proposals for intermediate and base load combustion turbines, the proposed low load subcategory includes only a single-phase BSER component.

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-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, 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[229] and operation would not qualify as the BSER; rather, the BSER should be lower

[229] 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.

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.

b. Proposed BSER

Consistent with the rationale of the 2015 NSPS, the EPA proposes 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. 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 proposes that the use of natural gas, Nos. 1 and 2 fuel oils, and other fuels [230] 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. The EPA is also proposing to add low-GHG hydrogen to the list of fuels meeting the uniform fuels criteria in 40 CFR part 60, subpart TTTTa. The addition of low-GHG hydrogen (and fuels derived from hydrogen) to 40 CFR part 60, subpart TTTTa would simplify the recordkeeping and reporting requirements for low load combustion turbines that elect to burn low-GHG hydrogen. As described in section VII.F, a component of the BSER for certain subcategories in subpart TTTTa is based on the use of low-GHG hydrogen. An owner/operator of a subpart TTTTa affected combustion turbine that combusts hydrogen for compliance purposes not meeting the definition of low-GHG hydrogen would be in violation of the subpart TTTTa requirements.

For the reasons discussed in the 2015 NSPS and noted above, the EPA is not proposing that efficient design and operation qualify as the BSER for the low load subcategory. The EPA is not proposing high-efficiency simple cycle or combined cycle turbine design and operation as the BSER for the low load subcategory because they are not necessarily cost reasonable and would not necessarily result in emission reductions. High efficiency combustion turbines have higher initial costs compared to lower efficiency combustion turbines. The cost of combustion turbine engines is dependent upon many factors, but the EPA estimates that the capital cost of a high-efficiency simple cycle turbine is 5 percent more than that of a comparable lower efficiency simple cycle turbine. Assuming all other costs are the same and that the high-efficiency simple cycle turbine uses 6 percent less fuel, it would not necessarily be cost reasonable to use a high-efficiency simple cycle turbine until the combustion turbine is operated at a 12-operating-month capacity factor of approximately 20 percent. At lower capacity factors, the CO_2 abatement costs on both a $/ton and $/MW basis increase rapidly.[231] Further, the emission rate of a low load combustion turbine is highly dependent upon the way the combustion turbine is operated. 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.

The EPA solicits 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. If high-efficiency simple cycle turbines do operate at higher part-load efficiencies and are able to reach the intended operating load more quickly, the use of highly efficient simple cycle turbines for low load applications would result in lower GHG reductions. In addition, the EPA solicits comment on the cost premium of high-efficiency simple cycle turbines. If the use of highly efficient simple cycle turbines results in GHG reductions at reasonable cost, their use could qualify as the BSER for low load combustion turbines. The EPA is soliciting comment on whether the BSER for new low load combustion turbines should be the use of high efficiency simple cycle technology. However, since the method of operation has a substantial impact on the emissions rate, it may not be feasible for to prescribe or enforce a single numerical standard of performance for affected sources strictly based on design efficiency. Accordingly, the EPA solicits comment on whether it would be appropriate to promulgate such a requirement as a design standard pursuant to CAA section 111(h). Pursuant to such a design standard, compliance would be demonstrated (i) initially, through an emissions test and (ii) subsequently, based on the use of lower emitting fuels. The initial full load performance test for natural gas-fired low load combustion turbines the EPA is considering is 1,150 lb CO_2/MWh-gross or 1,100 lb CO_2/MWh-gross.[232] Combustion turbine manufacturers conduct testing on their products and the initial performance test is equivalent to a design efficiency of approximately 35 and 36 percent, respectively. According to Gas Turbine World 2021, approximately three-fourths of simple cycle combustion turbines have design efficiencies of 35 percent or higher and half of simple cycle combustion turbines have design efficiencies of 36 percent or higher. The EPA is soliciting comment on if the initial performance test for low load combustion turbines could be conducted by the manufacturer certifying the design GHG emissions rate or if the owner or operator should be required to conduct separate testing to verify the emissions rate. The EPA notes that even if the Agency determines that a manufacturer design efficiency-based emissions requirement is appropriate for new low load combustion turbines, owners/operators would also have the option to either comply with the intermediate load standard of performance on a continuous basis or conduct an initial performance test as an alternative to purchasing a combustion turbine that

[230] 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 would demonstrate compliance with the low load subcategory.

[231] 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.

[232] The initial full load compliance test would be a 3-hour performance test and the measured emissions rate would be corrected to ISO conditions.

achieves the specified design efficiency. For example, owners/operators could elect to cofire low-GHG hydrogen or install integrated renewable generation as an alternative to purchasing a combustion turbine that meets the specified design efficiency.

The EPA expects that units in the low load subcategory will be simple cycle turbines. The capital cost of a combined cycle EGU is approximately 250 percent that of a comparable sized simple cycle EGU and would not be recovered by reduced fuel costs if operated as low load units. Furthermore, low load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation for the HRSG to begin generating steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

The EPA is not proposing the use of CCS or hydrogen co-firing as the BSER (or as a component of the BSER) for low load combustion turbines.[233] As described in the section discussing the second component of BSER for the intermediate load subcategory, the EPA is not proposing that CCS is the BSER for simple cycle combustion turbines based on the Agency's assessment that CCS may not be cost-effective for such combustion turbines when operated at intermediate load. This rationale applies with even greater force for low load combustion turbines. In addition, 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 do this is to use a HSRG, which is an integral component of a combined cycle turbine system but is not incorporated in a simple cycle unit. For these reasons, the Agency is not proposing that CCS qualifies as the BSER for this subcategory of sources.

The EPA is not proposing 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 announced hydrogen co-firing combustion turbine projects appear to be intermediate and base load combustion turbines. Manufacturers may focus initial research and development for hydrogen co-firing on combustion turbines that operate at higher capacity factors and that can achieve higher levels of overall GHG reductions. The EPA is soliciting comment on whether this development could limit the availability of low load combustion turbines that are capable of burning higher percentages of hydrogen. The EPA is also soliciting comment on technologies to reduce potential costs and technical challenges for the transport and storage of hydrogen for owners/operators of low load combustion turbines. In particular, the EPA is soliciting comment on approaches that could be used for owners/operators of low load combustion turbines located in high demand centers (*e.g.,* dense urban areas). To the extent these factors are not significant, the EPA is soliciting comment, with the intention of determining whether it would be appropriate to consider such a requirement in a future rulemaking, on whether the EPA should add a second component of the BSER for low load combustion turbines, based on hydrogen co-firing that would begin in 2032. The hydrogen co-firing requirement would be a separate requirement in addition to the proposed lower emitting fuels requirement. Based on simple cycle turbines that recently commenced operation, the average 12-operating-month capacity factor of low load combustion turbines would be less than 8 percent. If hydrogen co-firing were to qualify as the BSER, based on historical trends for construction of new simple cycle turbines and the operation of those turbines in 2021, a BSER based on 30 percent low-GHG hydrogen co-firing by volume for low load combustion turbines would result in annual reductions of 49,000 tons of CO_2.

2. BSER for Base Load and Intermediate Load Subcategories—First Component

This section describes the first component of the EPA's proposed BSER for newly constructed and reconstructed combustion turbines in the base load and intermediate load subcategories. For combustion turbines in the intermediate load subcategory, this first component of the BSER is the use of high-efficiency simple cycle turbine technology in combination with the best operating and maintenance practices. 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 is not proposing lower emitting fuels as the BSER for intermediate load or base load EGUs because, as described earlier in this section, it would achieve few GHG emission reductions compared to highly efficient generation.

b. Highly Efficient Generation

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 combustion turbines. Both types of turbines can also employ best operating and maintenance practices, which include routine operating and maintenance practices that minimize fuel use.

For simple cycle combustion 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 combustion turbines range from 33 to 40 percent. Best operating practices for simple cycle combustion 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 owner/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

[233] The EPA will not finalize the use of CCS or hydrogen co-firing as the BSER (or as a component of the BSER) for low load combustion turbines unless it first issues a subsequent notice of proposed rulemaking further evaluating such measures for that subcategory.

exhaust temperatures and are paired with steam turbines of 60 MW or less. These smaller combined cycle units are limited to using triple-pressure steam without a reheat cycle. This reduces the overall efficiency of the combined cycle unit by approximately 2 percent. Therefore, the EPA is proposing less stringent standards of performance for smaller combined cycle EGUs with base load ratings of less than 2,000 MMBtu/h relative to those for larger combined cycle combustion turbine EGUs. 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.

New technologies are available for new simple and combined cycle EGUs that could reduce emissions beyond what is currently being achieved by the best performing EGUs. For example, pressure gain combustion in the turbine engine would increase the efficiency of both simple and combined cycle EGUs. For combined cycle EGUs, the HRSG could be designed to utilize supercritical steam conditions or to utilize supercritical CO_2 as the working fluid instead of water; useful thermal output could be recovered from a compressor intercooler and boiler blowdown; and fuel preheating could be implemented. For additional information on these and other technologies that could reduce the emissions rate of new combustion turbines, see the *Efficient Generation at Combustion Turbine Electric Generating Units* TSD, which is available in the rulemaking docket. The EPA is soliciting comment on whether these technologies should be incorporated into a standard of performance based on an efficient generation BSER. To the extent commenters support the inclusion of emission reductions from the use of these technologies, the EPA requests that cost information and potential emission reductions be included.

i. Adequately Demonstrated

The EPA proposes that highly efficient simple cycle and combined cycle designs are adequately demonstrated because highly efficient simple cycle EGUs and highly efficient combined cycle EGUs 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 turbines. Approximately 14 percent of simple cycle and combined cycle combustion turbines that have commenced operation since 2015 have maintained emission rates below the proposed standards, demonstrating that the efficient generation technology described in this BSER is commercially available and that the standards of performance the EPA is proposing 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 that offset at least a portion of the increase in capital costs.

For the intermediate load subcategory, the EPA proposes 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 5 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 6 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 20 percent. Therefore, a BSER based on the use of high-efficiency simple cycle combustion turbines for intermediate load combustion turbines would have minimal, if any, overall compliance costs since the capital costs would be recovered through reduced fuel costs. The EPA considered but is not proposing combined cycle unit design for combustion turbines in the intermediate subcategory because the capital cost of a combined cycle EGU is approximately 250 percent that of a comparable-sized simple cycle EGU and because the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear. Furthermore, intermediate load combustion turbines start and stop so frequently that there might 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.

For the base load subcategory, the EPA proposes that the cost of high-efficiency combined cycle EGUs is 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.[234] 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. For additional information on costs, see the *Efficient Generation at Combustion Turbine Electric Generating Units* TSD, which is available in the rulemaking docket.

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

Use of highly efficient simple cycle and combined cycle 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 simple cycle turbines, compared to the use of less efficient simple cycle turbines, reduces all pollutants. Similarly, the use of high-efficiency combined combustion turbines, compared to the use of less efficient combine cycle 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 and intermediate load combustion turbines will not have significant impacts on the

[234] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022), *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf.*

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 and base load subcategories. As discussed in section VII.G, the EPA determined that the standards of performance reflecting this BSER are 1,150 lb CO_2/MWh-gross for intermediate load and 770 lb CO_2/MWh-gross for large base load combustion turbines.

Between 2015 and 2021, an average of 16 simple cycle turbines commenced operation per year. Of these, the EPA estimates that an average of six operated at greater than a 20 percent capacity factor on a 12-operating-month basis and thus would be considered intermediate load combustion turbines. For recent intermediate load simple cycle turbines, the EPA determined that the weighted average maximum 12-operating-month emissions rate [235] is 1,250 lb CO_2/MWh-gross. This is 8.3 percent higher than the proposed intermediate load standard of 1,150 lb CO_2/MWh-gross. Therefore, the EPA estimates that the proposed standard of performance based on the application of the proposed BSER for intermediate load combustion turbines would reduce the GHG emissions from those sources by 8.3 percent annually. Based on historical trends for construction of new simple cycle turbines and the operation of those turbines in 2021, the proposed standards for intermediate load combustion turbines would result in annual reductions of 44,000 tons of CO_2 as well as 13 tons of NO_X. For the base load subcategory, the weighted average maximum 12-operating-month emissions rate of large (base load ratings of 2,000 MMBtu/h or more) NGCC combustion turbines that commenced operation since 2015 has been 810 lb CO_2/MWh-gross. This is 5 percent higher than the proposed standard of 770 lb CO_2/MWh-gross for large base load combustion turbines. The only small, combined cycle combustion turbine (base load rating of 593 MMBtu/h) reporting emissions that commenced operation since 2015 has had a reported annual emissions rate of 870 lb CO_2/MWh-gross, which is slightly lower than the proposed standard of 875 lb CO_2/MWh-gross for a small base load combustion turbine with a base load rating of 593 MMBtu/h. Therefore, the EPA estimates that the proposed standards would require owners/operators to construct and maintain highly efficient combined cycle combustion turbines that would result in reductions in emissions of approximately 5 percent for new large stationary combustion EGUs and maintaining best performing emission rates for new small stationary combustion EGUs. Using historical trends for new combined cycle turbines and the operation of those combustion turbines in 2021, the proposed standards for base load combustion turbines would result in annual reductions of 940,000 tons of CO_2 as well as 75 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. This technology is more efficient than the average new generation technology and determining it to be a component of the BSER will advance its penetration throughout the industry. Accordingly, consideration of this factor supports the EPA's proposal to determine this technology to be the first component of the BSER.

c. Low-GHG Hydrogen and CCS

For reasons discussed in sections VII.F.3.b.v (CCS) and VII.F.3.c.vi (low-GHG hydrogen), the EPA is not proposing either CCS or co-firing low-GHG hydrogen as the first component of the BSER for intermediate load or base load EGUs.

d. Proposed BSER

The EPA proposes that highly efficient generating technology in combination with the best operating and maintenance practices is the first component BSER for base load and intermediate load combustion turbines and the phase 1 standards of performance are based on the application of that technology. Specifically, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices is the first component of the BSER for intermediate load combustion turbines. 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 a component of 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 would consider highly efficient generation to be a component of the BSER for base load and intermediate load combustion turbines even without taking this factor into account.

3. BSER for Base Load and Intermediate Load Subcategories—Second and Third Components

This section describes the proposed second (and in some cases third) component of the BSER for base load and intermediate load combustion turbines, which would be reflected in the second phase (and in some cases third phase) standards of performance. The proposed second component of the BSER for base load combustion turbines that are adopting the CCS pathway is the use of 90 percent CCS; and the corresponding standard of performance would apply beginning in 2035. The second component of the BSER for base load combustion turbines that are adopting the low-GHG hydrogen co-firing pathway and for intermediate load combustion turbines is co-firing 30 percent (by volume) low-GHG hydrogen and the corresponding standard of performance would apply beginning in 2032. The third component of the BSER would apply only to base load combustion turbines that are subject to a second phase standard that is based on co-firing 30 percent (by volume) low-GHG hydrogen. For those sources, the third component of the BSER is co-firing 96 percent (by volume) low-GHG hydrogen and the corresponding standard of performance would apply beginning in 2038. The EPA is also soliciting comment on whether intermediate load combustion turbines should be subject to a more stringent third phase standard based on 96 percent low-GHG hydrogen co-firing by 2038. A BSER based on 96 percent co-firing would result in a standard of

[235] The EPA is defining the achievable emissions rate as either the maximum 12-operating-month or the 99th percent confidence 12-operating-month emissions rate. The weighted average maximum emissions rate is the heat input weighted overall average of the maximum emission rates.

performance of 140 lb CO_2/MWh-gross for a natural gas-fired intermediate load combustion turbine.

a. Authority To Promulgate a Multi-Part BSER and Standard of Performance

The EPA's proposed 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 proposing to determine that the BSER is a set of controls that, depending on the subcategory, include either highly efficient generation plus use of CCS or highly efficient generation plus co-firing low-GHG hydrogen. The EPA is further proposing 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 co-firing 30 percent (by volume) low-GHG hydrogen and highly efficient generation in combination with 90 percent CCS—in 2032 and 2035, respectively. The EPA is also proposing that certain sources can apply the third component of the BSER—co-firing 96 percent (by volume) low-GHG hydrogen—by 2038.

Accordingly, the EPA is proposing 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 either two or three phases. Affected sources must comply with the first phase standards that are based on the application of the first component of the BSER upon initial startup of the facility. The second phase standards are based on the application of both the first and second components of the BSER by 2032 (for those sources utilizing co-firing low-GHG hydrogen) and by 2035 (for those sources utilizing CCS). The third phase standards are only applicable to those sources that are subject to a second phase standard of performance based on the highly efficient generation in combination with co-firing 30 percent (by volume) low-GHG hydrogen. The third phase standards for those sources are based on the application of the first component of the BSER and on the third component, which is co-firing 96 percent (by volume) low-GHG hydrogen by 2038. In this manner, this multi-phase standard of performance ''become[s] effective upon promulgation.'' CAA section 111(b)(1)(B). That is, upon promulgation, affected sources become subject to a standard of performance that limits their emissions immediately, which is the first phase of the standard of performance, and they also become subject to more stringent standards beginning in 2032 or later, which are the second and in some cases third phase of the standard of performance.

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.'' [236] 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 or low GHG-hydrogen-based controls necessary to comply with the second phase of the standards, and thereby ensures that the standards are achievable. Indeed, interpreting CAA section 111 to preclude phased implementation of standards of performance would be tantamount to interpreting the provision to preclude standards based on lead time, which would be contrary to the D.C. Circuit caselaw and common sense.

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 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).[237] *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).[238] 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 proposing 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 VII.F, the EPA has determined that the proposed BSER—highly efficient generation and use of CCS or highly efficient generation and co-firing low-GHG hydrogen—meet all of the statutory criteria and are adequately demonstrated for the compliance timeframes being proposed. Thus, the second and third phases of the standard of performance, if finalized, would apply to affected facilities that commence construction after the date of

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

[237] *Cf. New Jersey* v. *EPA,* 517 F.3d 574, 583–584 (D.C. Cir. 2008) (vacating rule on other grounds).

[238] *Cf. West Virginia* v. *EPA,* 142 S. Ct. 2587 (2022) (vacating rule on other grounds).

this 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 would 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 proposing 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 the date of these proposed standards of performance for new sources.

b. BSER for Base Load Subcategory of Combustion Turbines Adopting the CCS Pathway—Second Component

This section describes the second component of the BSER for the base load subcategory of combustion turbines that are adopting the CCS pathway. This subcategory is expected to include highly efficient combined cycle combustion turbines that primarily combust fossil fuels, and therefore have higher levels of CO_2 in the exhaust.

The EPA is proposing the use of CCS as the second component of the BSER for these combustion turbines. A detailed discussion of CCS follows. It should be noted that the EPA is also proposing use of CCS as the BSER for existing long-term coal-fired steam generating units (*i.e.,* coal-fired utility boilers), as discussed in section X.D of this preamble, as well as for large and frequently operated existing stationary combustion turbines. Many aspects of CCS are common to new combined cycle combustion turbines, existing long-term steam generating units, and existing stationary combustion turbines, and the following discussion details those common aspects and considerations.

i. Lower Emitting Fuels

The EPA is not proposing lower emitting fuels as the second component of the BSER for base load combustion turbines because it would achieve few emission reductions, compared to highly efficient generation in combination with the use of CCS.

ii. Highly Efficient Generation

For the reasons described above, the EPA is proposing that highly efficient generation technology 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 that are adopting the CCS pathway. Highly efficient generation reduces fuel use and the amount of CO_2 that must be captured by a CCS system. Since less flue gas needs to be treated, physically smaller carbon capture equipment may be used—potentially reducing capital, fixed, and operating costs.

iii. CCS

In this section of the preamble, the EPA provides a description of the components of CCS and evaluates it against the criteria to qualify as the BSER. CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system, such as a combustion turbine or a utility boiler. 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 and are moved through the flue gas duct system by fans. The concentration of CO_2 in most fossil fuel combustion flue gas streams is somewhat dilute. Most post-combustion capture systems utilize liquid solvents—most commonly amine-based solvents—that separate the CO_2 from the flue gas in CO_2 scrubber systems using chemical absorption (or chemisorption). 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.

Another technology, 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 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). These sequestration sites are widely available across the nation, and the EPA has developed a comprehensive regulatory structure to oversee geological sequestration projects and assure their safety and effectiveness. See 80 FR 64549 (October 23, 2015).

(A) Adequately Demonstrated

For new base load combustion turbines, the EPA proposes that CCS with a 90 percent capture rate, beginning in 2035, meets the BSER criteria. This amount of CCS is feasible and has been adequately demonstrated. The use of CCS at this level can be implemented at reasonable cost because it allows affected sources to maximize the benefits of the IRC section 45Q tax credit, and sources can maintain it over time by capturing a higher percentage at certain times in order to offset a lower capture rate at other times due to, for example, the need to undertake maintenance or due to unplanned capture system outages. Higher capture rates may be possible—the 2022 NETL Baseline report evaluated capture rates at 90 and 95 percent with marginal differences in cost. The Agency is soliciting comment on the range of the capture rate of CO_2 at the stack from 90 to 95 percent or greater. The EPA also notes that the operating availability (the fraction of time CCS equipment is operational relative to the operation of the combustion turbine) may be less than 100 percent and is therefore soliciting comment on a range in emission reduction from 75 to 90 percent, as further discussed in section VII.G.2 of this preamble.

The EPA previously determined ''partial CCS'' to be a component of the BSER (in combination with the use of a highly efficient supercritical utility boiler) for new coal-fired steam generating units as part of the 2015 NSPS (80 FR 64538; October 23, 2015).[239] As described in that action, reiterated in this section of the preamble, and detailed further in accompanying TSDs available in the docket for this rulemaking, numerous projects demonstrate the feasibility and effectiveness of CCS technology.

In the 2015 NSPS, the EPA 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

[239] In the present action, the EPA is not re-opening any aspect of the CCS determinations in the 2015 NSPS.

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.[240] 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.'' [241] Id. at 64541–42. In the present action, the EPA is applying the same legal interpretation and is not reopening it for comment.

(1) CO_2 Capture Technology

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 and industrial sources in addition to combustion turbines. While the EPA would propose that the CO_2 capture component of CCS is adequately demonstrated on those bases alone, this determination is further corroborated by EPAct05-assisted projects.

Various technologies may be used to capture CO_2, the details of which are described in the *GHG Mitigation Measures for Steam Generating Units* TSD, which is available in the rulemaking docket.[242] 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.[243] Lastly, as noted above, 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.

Solvent-based capture processes usually use an amine (*e.g.,* monoethanolamine, MEA). 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 potential contaminants in the flue gas, including SO_2. 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 cooled and sent back to the absorption column, and any spent solvent is replenished with new solvent.

(2) Capture Demonstrations at Coal-Fired Steam Generating Units and Industrial Processes

The function, design, and operation of post-combustion CO_2 capture equipment is similar, although not identical, for both steam generating units and combustion turbines. As a result, application of CO_2 capture at existing coal-fired steam generating units helps demonstrate the adequacy of the CO_2 capture component of CCS.

SaskPower's Boundary Dam Unit 3, a 110 MW lignite-fired unit in Saskatchewan, Canada, has demonstrated 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, was the first full-scale CO_2 capture system retrofit on an existing coal-fired power plant. It uses the amine-based Shell CANSOLV process, with integrated heat and power from the steam generating unit.[244] While successfully demonstrating the commercial-scale feasibility of 90 percent capture rates, the plant has also provided valuable lessons learned for the next generation of capture plants. A feasibility study for SaskPower's Shand Power Station indicated achievable capture rates of 97 percent, even at lower loads.[245]

For all industrial processes, operational availability (the percent of time a unit operates relative to its planned operation) is usually less than 100 percent due to unplanned maintenance and other factors. As a first-of-a-kind commercial-scale project, Boundary Dam Unit 3 experienced some additional challenges with availability during its initial years of operation, due to the fouling of heat exchangers and issues with its CO_2 compressor.[246] However, identifying and correcting those problems has improved the operational availability of the capture system. The facility has reported greater than 90 percent capture system

[240] 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 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.''

[241] In the 2015 NSPS, the EPA adopted several other legal interpretations of these EPAct05 provisions as well, which it is not reopening in this rule. See 80 FR 64541 (October 23, 2015).

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

[243] 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.

[244] 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.*

[245] 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.*

[246] 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.*

availability in the second and third quarters of 2022.[247] Currently, newly constructed and retrofit CO_2 capture systems are anticipated to have operational availability of around 90 percent, on the same order of that is expected at coal-fired steam generating units. The EPA is soliciting comment on information relevant to the expected operational availability of new and retrofit CO_2 capture systems.

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 (80 FR 64548–54; October 23, 2015). Amine-based carbon capture has 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.[248] At the 180–MW 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 coal-fired Shady Point plant captured CO_2 from an approximate 5 percent slipstream (about 66,000 metric tons of CO_2 per year) from 2001 through around 2019.[249] These facilities, which have operated for multiple years, clearly show the technical feasibility of post-combustion carbon capture.

The capture component of CCS has also been demonstrated at other industrial processes. Since 1978, the Searles Valley Minerals soda ash plant in Trona, California, has used an amine-based system to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of a coal-fired industrial power plant that generates steam and power for onsite use. The captured CO_2 is used for the carbonation of brine in the process of producing soda ash.[250]

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.[251] The Quest facility has been operating since 2015 and captures approximately 1 million metric tons of CO_2 per year.

(3) Capture Demonstrations at Combustion Turbines

While most demonstrations of CCS have been for applications other than combustion turbines, CCS has been successfully applied to an existing combined cycle EGU and several other projects are in development, as discussed immediately below. Currently available post-combustion amine-based carbon capture systems require that the flue gas be cooled prior to entering the carbon capture equipment. This holds true for the exhaust from a combustion turbine. The most energy efficient way to do this is to use a HSRG—which, as explained above, is an integral component of a combined cycle turbine system—to generate additional useful output. Because simple cycle combustion turbines do not incorporate a HRSG, the Agency is not considering the use of CCS as a potential component of the BSER for them.

(a) CCS on Combined Cycle EGUs

Examples of the use of CCS on combined cycle EGUs include the Bellingham Energy Center in south central Massachusetts and the proposed Peterhead Power Station in Scotland. The Bellingham plant used Fluor's Econamine FG Plus℠ capture system and demonstrated the commercial viability of carbon capture on a combined cycle combustion turbine EGU using first-generation technology. The 40-MW slipstream capture facility operated from 1991 to 2005 and captured 85 to 95 percent of the CO_2 in the slipstream for use in the food industry.[252] In Scotland, the proposed 900-MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. 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 might serve as a destination for the captured CO_2.[253] Moreover, an 1,800-MW NGCC EGU that will be constructed in West Virginia and will utilize CCS has been announced. The project is planned to begin operation later this decade, and its feasibility was partially credited to the expanded IRC section 45Q tax credit for sequestered CO_2 provided through the IRA.[254]

(b) Net Power Cycle

In addition, there are several planned projects using the NET Power Cycle.[255] The NET Power Cycle is a proprietary process for producing electricity that combusts a fuel with purified oxygen 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.[256] Potential advantages of this cycle are that it emits no NO_X and produces a stream of high-purity CO_2 [257] 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 was synchronized to the grid in 2021. There are several announced commercial projects proposing to use the NET Power Cycle. These include the 280-MW Broadwing Clean Energy Complex in Illinois, and several international projects.

(4) EPAct05-Assisted CO_2 Capture Projects

While the EPA is proposing that the capture component of CCS is adequately demonstrated based solely on the other demonstrations of CO_2 capture discussed in this preamble, adequate demonstration of CO_2 capture technology is further corroborated by

[247] SaskPower (October 18, 2022). *BD3 Status Update: Q3 2022. https://www.saskpower.com/about-us/our-company/blog/2022/bd3-status-update-q3-2022.*

[248] 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.

[249] 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/.*

[250] IEA (2009), World Energy Outlook 2009, OECD/IEA, Paris.

[251] 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.*

[252] 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.*

[253] 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/.*

[254] 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-combinedcycle-natural-gas-power-station-with-carbon-capture-announced-in-west-virginia/.*

[255] *https://netpower.com/technology/.* The Net Power Cycle was formerly referred to as the Allam-Fetvedt cycle.

[256] 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/.*

[257] This allows for capture of over 97 percent of the CO_2 emissions. *www.netpower.com.*

CO_2 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).

(a) EPAct05-Assisted CO_2 Capture Projects at Coal-Fired Steam Generating Units

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 W.A. Parish Generating Station in Thompsons, Texas, and began operation in 2017, successfully capturing and sequestering CO_2 for several years. Although the system was put into reserve shutdown (*i.e.,* idled) in May 2020, citing the poor economics of utilizing captured CO_2 for enhanced oil recovery (EOR) at that time, there are reports of plans to restart the capture system.[258] A final report from National Energy Technology (NETL) details the success of the project and what was learned from this first-of-a-kind demonstration at scale.[259] 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 and is optimized for CO_2 capture from a coal-fired generator's flue gas. 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. Plant Barry in Mobile, Alabama, began using the KM–CDR Process® in 2011 for a fully integrated 25-MW CCS project with a capture rate of 90 percent.[260] The CCS project at Plant Barry captured approximately 165,000 tons of CO_2 annually, which is then transported via pipeline and sequestered underground in geologic formations. See 80 FR 64552 (October 23, 2015).

[258] ''The World's Largest Carbon Capture Plant Gets a Second Chance in Texas'' Bloomberg News, February 8, 2023. *https://www.bloomberg.com/news/articles/2023-02-08/the-world-s-largest-carbon-capture-plant-gets-a-second-chance-in-texas?leadSource=uverify%20wall.*

[259] 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.*

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

(b) EPAct05-Assisted CO_2 Capture Projects at Stationary Combustion Turbines

There are several EPAct05-assisted projects related to NGCC units including:[261 262 263 264 265]

- General Electric (GE) (Bucks, Alabama) was awarded $5,771,670 to retrofit an NGCC facility 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 NGCC 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 NGCC 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 NGCC flue gas and improve scalability to large NGCC plants.

[261] 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.*

[262] 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/.*

[263] 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.*

[264] 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.*

[265] 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.*

- 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 NGCC 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 NGCC 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 NGCC 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 NGCC 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 NGCC 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 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 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 2026.

(5) CO_2 Transport

(a) Demonstration of CO_2 Transport

The majority of CO_2 transported in the U.S. is transported through pipelines. Pipeline transport of CO_2 has been occurring for nearly 60 years, and over this time, the design, construction, and operational requirements for CO_2 pipelines have been demonstrated.[266] Moreover, the U.S. CO_2 pipeline network has steadily expanded, and appears primed to continue to do so. The Pipeline and Hazardous Materials

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

Safety Administration (PHMSA) reported that 5,339 miles of CO_2 pipelines were in operation in 2021, a 13 percent increase in CO_2 pipeline miles since 2011.[267] Moreover, several major projects have recently been announced to expand the CO_2 pipeline network across the U.S. For example, the Midwest Carbon Express has proposed to add more than 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 2024.[268] Another example is the Heartland Greenway project, which has proposed to add more than 1,300 miles of dedicated CO_2 pipeline in Iowa, Nebraska, South Dakota, Minnesota, and Illinois. The Heartland Greenway project is projected to start its initial system commissioning in the second quarter of 2025.[269] The proximity to existing or planned CO_2 pipelines and geologic sequestration sites can be a factor to consider in the construction of stationary combustion turbines, and pipeline expansion, when needed, has been proven to be feasible.[270] [271] The IIJA also included substantial support for CO_2 transportation infrastructure.

(b) Security of CO_2 Transport

The safety of existing and new CO_2 pipelines that transport CO_2 in a supercritical state is exclusively regulated by PHMSA. These regulations include standards related to pipeline design, construction, and testing, 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.[272] Furthermore, PHMSA initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of supercritical CO_2 pipelines following investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020.[273] Following that 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.[274] PHMSA has further issued an updated nationwide advisory bulletin to all pipeline operators, and solicited research proposals to strengthen CO_2 pipeline safety.[275] Additionally, 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.[276] [277] These CO_2 pipeline controls, in addition to the PHMSA standards, ensure that captured CO_2 will be securely conveyed to a sequestration site.

States are also directly involved in siting proposed CO_2 pipeline projects. CO_2 pipeline siting authorities, landowner rights, and eminent domain laws reside with the States and vary from State to State. Pipeline developers may secure rights-of-way for proposed projects through voluntary agreements with landowners; pipeline developers may also secure rights-of-way through eminent domain authority, which typically accompanies siting permits from State utility regulators with jurisdiction over CO_2 pipeline siting.[278]

Transportation of CO_2 via pipeline is the most viable and cost-effective method at the scale needed for sequestration of captured EGU CO_2 emissions. However, CO_2 can also be liquified and transported via vessel (*e.g.,* ship), highway (*e.g.,* cargo tank, portable tank), ship, or rail (*e.g.,* tank cars) when pipelines are not available. Liquefied natural gas and liquefied petroleum gases are already routinely transported via ship at a large scale, and the properties of liquified CO_2 are not significantly different.[279] In fact, the food and beverage as well as specialty gas industries already have experience transporting CO_2 by rail.[280] Highway road tankers and rail transportation can provide for the transport of smaller quantities of CO_2 and can be used in tandem with other modes of transportation to move CO_2 captured from an EGU.[281]

(6) Geologic Sequestration of CO_2

(a) Security of Sequestration

Geologic sequestration (or storage), which is the long-term containment of a CO_2 stream in subsurface geologic formations, is well proven and broadly available in many locations across the U.S. Independent analyses of the potential availability of geologic sequestration capacity in the United States have been conducted by DOE, and the U.S. Geological Survey (USGS) has also undertaken a comprehensive assessment of geologic sequestration resources in the U.S.[282] [283] Geologic sequestration is based on a demonstrated understanding of the trapping processes that retain CO_2 in the subsurface; most importantly, geologic sequestration occurs securely when the CO_2 is trapped under a low permeability

[267] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2021. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[268] Beach, Jeff. ''World's Largest Carbon Capture Pipeline Aims to Connect 31 Ethanol Plants, Cut across Upper Midwest.'' Agweek, December 6, 2021. *https://www.agweek.com/business/worlds-largest-carbon-capture-pipeline-aims-to-connect-31-ethanol-plants-cut-across-upper-midwest.*

[269] Navigator CO_2. ''NavCO_2 Fact Sheet.'' 2022. *https://d3o151.p3cdn1.secureserver.net/wp-content/uploads/2022/08/HG-Fact-Sheet-vFINAL.pdf.*

[270] For additional information regarding planned or announced pipelines please see section 4.6.1.2 of the *GHG Mitigation Measures for Steam Generating Units* TSD.

[271] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2021. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[272] See generally 49 CFR 190–199.

[273] PHMSA, ''PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak.'' 2022. *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[274] Consent Order, Denbury Gulf Coast Pipelines, LLC, CPF No. 4–2022–017–NOPV (U.S. Dep't of Transp. Mar. 24, 2023). *https://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_42022017NOPV.html?nocache=7208.*

[275] Ibid.

[276] 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.*

[277] 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.*

[278] Congressional Research Service. 2022. *Carbon Dioxide Pipelines: Safety Issues,* June 3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[279] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[280] EU CCUS Projects Network. (2019). Briefing on Carbon Dioxide Specifications for Transport. *https://www.ccusnetwork.eu/sites/default/files/TG3_Briefing-CO2-Specifications-for-Transport.pdf.*

[281] Ibid.

[282] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition,* September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.*

[283] 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/.*

seal. There have been numerous efforts demonstrating successful geologic sequestration projects 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.

(i) Demonstration of Geologic Sequestration

Existing project and regulatory experience, along with other information, indicate that geologic sequestration is a viable long-term CO_2 sequestration option. The effectiveness of long-term trapping of CO_2 has been demonstrated by natural analogues in a range of geologic settings where CO_2 has remained trapped for millions of years.[284] For example, CO_2 has been trapped for more than 65 million years in the Jackson Dome, located near Jackson, Mississippi.[285] Other examples of natural CO_2 sources include the Bravo Dome and the McElmo Dome in New Mexico and Colorado, respectively.[286] These naturally occurring sequestration sites demonstrate the feasibility of containing the large volumes of CO_2 that may be captured from fossil fuel-fired EGUs, as these sites have held volumes of CO_2 that are much larger than the volume of CO_2 expected to be captured from a fossil fuel-fired EGU over the course of its useful life. In 2010, the DOE estimated CO_2 reserves of 594 million metric tons at Jackson Dome, 424 million metric tons at Bravo Dome, and 530 million metric tons at McElmo Dome.[287] Between 2000 and 2020, the Department of Energy-sponsored research totaling $1 billion to prove carbon storage technologies and enable large-scale deployment. 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 11 million tons of CO_2 with no indications of negative impacts to either human health or the environment.[288] Building on this experience, the Department of Energy 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 potential sequestration sites greater than 50 million tons.[289]

Numerous additional saline facilities are under development across the United States. The Great Plains Synfuel Plant currently captures 2 million metric tons of CO_2 per year, which is used for enhanced oil recovery (EOR); a planned addition of saline sequestration for this facility is expected to increase the amount captured and sequestered (through both geologic sequestration and EOR) to 3.5 million metric tons of CO_2 per year.[290] The EPA is currently reviewing Underground Injection Control (UIC) Class VI geologic sequestration well permit applications for proposed sequestration sites in at least seven States.[291] [292]

Geologic sequestration has been proven to be successful and safe in projects internationally. The oldest international facility has geologically sequestered CO_2 for over twenty years. In Norway, facilities conduct offshore sequestration under the Norwegian continental shelf.[293] 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.[294] 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 storage facility at Boundary Dam Power Station in Saskatchewan, Canada had, as of mid-2022, captured 4.6 million tons of CO_2 since it began operating in 2014.[295] Other international sequestration facilities in operation include Glacier Gas Plant MCCS (Canada),[296] Quest (Canada), and Qatar LNG CCS (Qatar).

(ii) EPAct05-Assisted Geologic Sequestration Projects

While the EPA is proposing that the sequestration component of CCS is adequately demonstrated based solely on the other demonstrations of geologic sequestration discussed in this preamble, adequate demonstration of geologic sequestration is further corroborated by geologic sequestration currently operational and planned 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).

Two saline sequestration facilities are currently in operation in the U.S. and several are under development.[297] The Illinois Industrial Carbon Capture and Storage Project began injecting CO_2 from ethanol production into the Mount Simon Sandstone in April 2017. The project has the potential to store up to 5.5 million metric tons of CO_2,[298] and, according to the facility's report to the EPA's GHGRP, as of 2021, 2.5 million metric tons of CO_2 had been injected

[284] Holloway, S., *et al.* Natural Emissions of CO_2 from the Geosphere and their Bearing on the Geological Storage of Carbon Dioxide. 2007. Energy 32: 1194–1201.

[285] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[286] See K.J. Sathaye, M.A. Hesse, M. Cassidy, D.F. Stockli, ''Constraints on the magnitude and rate of CO_2 dissolution at Bravo Dome natural gas field.'' *Proceedings of the National Academy of Sciences* 111, 15332–15337. 2014. and Kinder Morgan. ''Carbon Dioxide (CO_2) Operations; CO_2 Supply.'' *https://www.kindermorgan.com/Operations/CO2/Index.*

[287] DiPietro, P., *et al.* 2012. ''A Note on Sources of CO_2 Supply for Enhanced-Oil Recovery Operations.'' SPE Economics & Management.

[288] Safe Geologic Storage of Captured Carbon Dioxide—DOE's Carbon Storage R&D Program: Two Decades in Review,'' National Energy Technology Laboratory, Pittsburgh, April 13, 2020. *https://www.netl.doe.gov/sites/default/files/Safe%20Geologic%20Storage%20of%20Captured%20Carbon%20Dioxide_April%2015%202020_FINAL.pdf.*

[289] *https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe.*

[290] Basin Electric Power Cooperative. ''Great Plains Synfuels Plant Potential to Be Largest Coal-Based Carbon Capture and Storage Project to Use Geologic Storage,'' September 9, 2021. *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.*

[291] UIC regulations for Class VI wells facilitate the injection of CO_2 for geologic sequestration while protecting human health and the environment 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.F.3.b.iii.

[292] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 12, 2023. *https://www.epa.gov/uic/class-vi-wells-permitted-epa.*

[293] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[294] Zapantis, Alex, Noora Al Amer, Ian Havercroft, Ruth Ivory-Moore, Matt Steyn, Xiaoliang Yang, Ruth Gebremedhin, *et al.* ''Global Status of CCS 2022.'' Global CCS Institute, 2022. *https://status22.globalccsinstitute.com/2022-status-report/introduction/.*

[295] Boundary Dam Carbon Capture Project. *https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Carbon-Capture-and-Storage/Boundary-Dam-Carbon-Capture-Project.*

[296] Zapantis, Alex, Noora Al Amer, Ian Havercroft, Ruth Ivory-Moore, Matt Steyn, Xiaoliang Yang, Ruth Gebremedhin, et al. ''Global Status of CCS 2022.'' Global CCS Institute, 2022. *https://status22.globalccsinstitute.com.*

[297] Zapantis, Alex, Noora Al Amer, Ian Havercroft, Ruth Ivory-Moore, Matt Steyn, Xiaoliang Yang, Ruth Gebremedhin, *et al.* ''Global Status of CCS 2022.'' Global CCS Institute, 2022. *https://status22.globalccsinstitute.com/.*

[298] Archer Daniels Midland, Monitoring, Reporting, and Verification Plan CCS#2, 2017. *https://www.epa.gov/sites/default/files/2017-01/documents/adm_mrv_plan.pdf.*

into the saline reservoir.[299] The Red Trail Energy CCS facility in North Dakota, which is the first saline sequestration facility in the U.S. to operate under a State-led regulatory authority for carbon storage, began injecting CO_2 from ethanol production in 2022.[300] This project is expected to inject a total of 3.7 million tons of CO_2 over its lifetime.[301]

There are additional planned geologic sequestration facilities across the United States.[302] 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.[303] Finally, in Wyoming, Class VI permit applications have been filed for a proposed saline sequestration facility located in Southwestern Wyoming. At full capacity, the facility will permanently store up to 5 million metric tons of CO_2 annually from industrial facilities in the Nugget saline sandstone reservoir.[304]

(iii) Security of Geologic Sequestration

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).

Based on the understanding developed from natural analogs and existing projects, the security of sequestered CO_2 is expected to increase over time after injection ceases.[305] 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.[306] In addition, site characterization, site operations, and monitoring strategies as required through the Underground Injection Control (UIC) Program and the GHGRP, discussed below, work in combination to ensure security and transparency.

The UIC Program, the GHGRP and other regulatory requirements comprise a detailed regulatory framework for facilitating geologic sequestration in the U.S., according to a 2021 report from the Council on Environmental Quality (CEQ). This framework is already in place and capable of reviewing and permitting CCS activities.[307]

This regulatory framework includes the UIC Class VI well regulations, promulgated under the authority of the Safe Drinking Water Act (SDWA); and the GHGRP, promulgated 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. The UIC regulations facilitate the injection of CO_2 for geologic sequestration while protecting human health and the environment 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 program to assist States and Tribal regulatory authorities interested in Class VI primacy.[308] As the EPA considers Class VI primacy applications, it has indicated that it will require approaches that balance the use of geologic sequestration with mitigation of impacts on vulnerable communities. States and Tribes applying for Class VI primacy are asked to support communities by implementing an inclusive public participation process, considering environmental justice impacts on communities, enforcing Class VI regulatory protections and incorporating other mitigation measures.[309]

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, also referred to as ''GHGRP subpart RR.''

The GHGRP subpart RR requirements provide the monitoring mechanisms to identify, quantify, and address potential leakage. The EPA designed them to complement and build on UIC monitoring and testing requirements. Although the regulations for the UIC program are designed to ensure protection of USDWs from endangerment, the practical effect of these GHGRP subpart RR requirements is that they also prevent releases of CO_2 to the atmosphere.[310]

Major components to be included in UIC Class VI permits are site characterization, area of review,[311] corrective action,[312] well construction and operation, testing and monitoring, financial responsibility, post-injection site care, well plugging, emergency and remedial response, and site closure. 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.[313] GHGRP subpart RR requires facilities

[299] EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.

[300] Zapantis, Alex, Noora Al Amer, Ian Havercroft, Ruth Ivory-Moore, Matt Steyn, Xiaoliang Yang, Ruth Gebremedhin, et al. ''Global Status of CCS 2022.'' Global CCS Institute, 2022. *https://status22.globalccsinstitute.com.*

[301] North Dakota Industrial Commission, NDIC Case No. 28848—Draft Permit Fact Sheet and Storage Facility Permit Application.'' *https://www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp.* This injection well is permitted by North Dakota.

[302] 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.*

[303] Project Tundra. ''Project Tundra.'' *https://www.projecttundrand.com/.*

[304] Wyoming DEQ Class VI Permit Applications. *https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/.*

[305] ''Report of the Interagency Task Force on Carbon Capture and Storage.'' 2010. *https://www.osti.gov/servlets/purl/985209.*

[306] See, *e.g.,* Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[307] 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.*

[308] On April 27, 2023, the EPA Administrator signed a proposed rule to approve the State of Louisiana's request to have primacy for UIC Class VI wells within the state. Louisiana is the third state to request primacy for UIC Class VI wells. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[309] 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.*

[310] In 2022, EPA proposed a new GHGRP subpart, ''Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery (EOR) Using ISO 27916'' (or GHGRP subpart VV). For more information on proposed GHGRP subpart VV, see section VII.K.2 of this preamble.

[311] 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.

[312] UIC permitting authorities may require corrective action for existing wells within the area of review to ensure protection of underground sources of drinking water.

[313] 40 CFR 98.440.

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.[314 315 316 317] Although deep subsurface monitoring is required for UIC Class VI wells at 40 CFR 146.90 and is the primary means of determining if there are any leaks to a USDW, and is generally effective in doing so, the surface air and soil gas monitoring employed under a GHGRP subpart RR MRV Plan can be utilized in addition to subsurface monitoring required under 40 CFR 146.90, if required by the UIC Program Director under 40 CFR 146.90(h), to further ensure protection of USDWs.[318] 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.[319]

Geologic sequestration efforts on Federal lands as well as those efforts that are directly supported with Federal funds may need to comply with other regulations, depending on the nature of the project.[320]

(b) Broad Availability of Sequestration

Geologic sequestration potential for CO_2 is widespread and available throughout the U.S. Nearly every State in the U.S. has or is in close proximity to formations with geologic sequestration potential, including areas offshore. These areas include deep saline formation, unmineable coal seams, and oil and gas reservoirs. Moreover, the amount of storage capacity can readily accommodate the amount of CO_2 for which sequestration could be required under this proposed rule.

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 U.S. 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).[321] 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.[322] The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential across the U.S.[323]

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 U.S. 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.[324 325]

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 U.S., and are located in 22 States.[326]

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 six-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.[327 328] DOE has judged unmineable coal seams worthy of inclusion in the NETL Atlas.[329]

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.[330] Further, the reduced injectivity can be anticipated and accommodated in sizing and characterizing prospective sequestration sites.

There is sufficient technical basis and scientific evidence that depleted oil and gas reservoirs represent another option for geologic storage. The reservoir characteristics of older fields are well known as a result of exploration and many years of hydrocarbon production and, in many areas, infrastructure

[314] 40 CFR 98.446.

[315] 40 CFR 98.448.

[316] 40 CFR 98.446(f)(9) and (10).

[317] 40 CFR 98.446(f)(12).

[318] See 75 FR 77263 (December 10, 2010).

[319] 40 CFR 98.448(a).

[320] 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*.

[321] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition,* September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.

[322] Ibid.

[323] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, National assessment of geologic carbon dioxide storage resources—Summary: U.S. Geological Survey Factsheet 2013–3020. 2013. *https://pubs.usgs.gov/fs/2013/3020/*.

[324] Alaska has deep saline formation storage capacity, geology amenable to EOR operations, and potential geologic sequestration capacity in unmineable coal seams.

[325] The U.S. DOE NETL Carbon Storage Atlas, Fifth Edition did not assess deep saline formation potential for Alaska, Connecticut, Hawaii, Maine, Massachusetts, Nevada, New Hampshire, Rhode Island, and Vermont. We are assuming for purposes of our analysis here that they do not have storage potential in this type of formation.

[326] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition,* September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.

[327] M. Godec *et al.,* ''CO_2-ECBM: A Review of its Status and Global Potential,'' Energy Procedia 63: 5858–5869 (2014). *https://doi.org/10.1016/j.egypro.2014.11.619*.

[328] N. Ripepi *et al.,* ''Central Appalachian Basin Unconventional (Coal/Organic Shale) Reservoir Small Scale CO_2 Injection,'' US DOE/NETL Annual Carbon Storage and Oil and Natural Gas Technologies Review Meeting (2017). *https://www.netl.doe.gov/sites/default/files/event-proceedings/2017/carbon-storage-oil-and-natural-gas/thur/Nino-Ripepi-VirginiaTech.DOE Meeting.CoalShaleUpdate.8.3.2017.pdf*.

[329] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition,* September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.

[330] Xiachun Li & Zhi-Ming Fang, ''Current Status and Technical Challenges of CO_2 Storage in Coal Seams and Enhanced Coalbed Methane Recovery: An Overview,'' International Journal of Coal Science & Technology, 93, 99 (2014) (suggesting existing technologies that can be used to address injectivity reduction in unmineable coal seams).

already exists for CO_2 transportation and storage.[331] 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.[332]

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. The distance of 100 km is consistent with the assumptions underlying the NETL cost estimates for transporting CO_2 by pipeline.[333] Overall, the EPA found that 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. There are additional areas that have not yet been assessed and may provide additional infrastructure capability.[334]

As described in the 2015 NSPS, electricity demand in States that may not have geologic sequestration sites may be served by new generation, including new base load combustion turbines, built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines.[335] This approach has long been used in the electricity sector because siting an EGU away from a load center and transmitting the generation long distances to the load area can be less expensive and easier to permit than siting the EGU near the load area.

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),[336] 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. For example, the Prairie State Generating Plant, a 1,600-MW coal-fired EGU in Illinois that is currently considering retrofitting with CCS, serves load in eight different States from the Midwest to the mid-Atlantic.[337] The Intermountain Power Project, a coal-fired plant located in Delta, Utah, that is converting to burn hydrogen and natural gas, serves customers in both Utah and California.[338]

(B) 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 is proposing that the costs of CCS for new combined cycle units are 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. For additional details on the EPA's CCS costing analysis see the *GHG Mitigation Measures for Steam Generating Units* TSD, which is available in the rulemaking docket.

(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.[339] For a base load combustion turbine, carbon capture increases the LCOE by 61 percent (an increase of 27 $/MWh) and has an estimated cost of $81/ton ($89/metric ton) of onsite CO_2 reduction.[340] The NETL costs are based on the use of a second generation amine-based capture system without exhaust gas recirculation (EGR) and does not take into account further cost reductions that can be expected to occur as post-combustion capture systems are more widely deployed.

The flue gas from NGCC EGUs differs from that of a coal-fired EGUs in several ways that impact the cost of CO_2 capture. These include that the CO_2 concentration is approximately one-third, 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. The higher amount of excess oxygen has the potential to reduce the efficiency of amine-based solvents that are susceptible to oxidation. 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 of 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

[331] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[332] Goodman, A., *et al.* ''Methodology for Assessing CO_2 Storage Potential of Organic-Rich Shale Formations.'' *Energy Procedia,* 12th International Conference on Greenhouse Gas Control Technologies, GHGT–12, 63 (2014): 5178–84. *https://doi.org/10.1016/j.egypro.2014.11.548.* NETL DOE. ''Big Sky Carbon Sequestration Partnership.'' *https://netl.doe.gov/coal/carbon-storage/atlas/bscsp.* Schaef, T., and McGrail, P. ''Sequestration of CO_2 in Basalt Formations.'' Pacific Northwest National Laboratory, NETL, DOE, 2013. *https://www.netl.doe.gov/sites/default/files/event-proceedings/2013/carbon%20storage/8-00-Schaef-58159-Task-1-082213.pdf.*

[333] Although a 100 km pipeline is used in this analysis, this does not represent a technical limitation, but rather a standardization used for NETL cost estimates. As noted in the *GHG Mitigation Measures for Steam Generating Units* TSD, large pipelines connect CO_2 sources in south central Colorado, northeast New Mexico, and Mississippi to Texas, Oklahoma, New Mexico, Utah, and Louisiana. Additionally, as noted in section VII.F.3.b.iii.(5) of this preamble, CO_2 can by transported via other modes such as ship, road tanker, or rail tank cars.

[334] *GHG Mitigation Measures for Steam Generating Units* TSD, chapter 4.6.2. As discussed in the TSD, geologic sequestration potential has not yet been assessed for Connecticut, Hawaii, Nevada, New Hampshire, Rhode Island, and Vermont, and may provide additional infrastructure capability.

[335] This was described as ''coal-by-wire'' in the 2015 NSPS.

[336] In this discussion, the term RTO indicates both ISOs and RTOs.

[337] *https://prairiestateenergycampus.com/about/ownership/.*

[338] *https://www.ipautah.com/participants-services-area/.*

[339] CCS reduced the net output of the NETL F class combined cycle EGU from 726 MW to 645 MW.

[340] These calculations use a service life of 30 years, an interest rate of 7.0 percent, a natural gas price of $3.69/MMBtu, and a capacity factor of 65 percent. These costs do not include CO_2 transport, storage, or monitoring costs.

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.[341]

Furthermore, the EPA expects that the costs of capture systems will also decrease over the rest of this decade and continue to decrease afterwards. As part of the plan to reduce the costs of CO_2 capture, the DOE is funding multiple projects to advance CCS technology.[342] It should be noted that these projects are EPAct05-assisted. The EPA proposes that the rest of the information it has is sufficient to support a determination that the costs of capture systems are reasonable, and that CCS is adequately demonstrated. These EPAct05-assisted projects provide additional confirmation for this proposal because they will contribute to improvements in the costs of CCS. These include projects falling under carbon capture research and development, engineering-scale testing of carbon capture technologies, and engineering design studies for carbon capture systems. The projects will aim to capture CO_2 from various point sources, including NGCC units, cement manufacturing plants, and iron and steel plants. The general aim is to reach 95 percent or greater capture of CO_2, to lower the costs of the technologies, and to prove feasible scalability at the industrial scale for these new technologies. Some projects are designed solely to develop new carbon capture technologies, while others are designed to apply existing technologies at the industrial scale. For a list of notable projects, see section VII.F.3.b.iii(A)(4)(b) of this preamble.

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 have 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[343] systems. It is 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, increasing the economic competitiveness of CCS.[344] 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.[345] 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.[346] 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. Studies of the cost of capture and compression of CO_2 from power stations completed ten 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.[347] 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.[348] 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 that utilize the coal found in Illinois, East Texas, Williston, and Powder River basins.[349]

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[341] Energy Procedia. (2014). *Impact of exhaust gas recirculation on combustion turbines. Energy and economic analysis of the CO_2 capture from flue gas of combined cycle power plants. https://www.sciencedirect.com/science/article/pii/S1876610214001234.*

[342] The DOE has also previously funded FEED studies for NGCC facilities. These include FEED studies at existing NGCC 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.

[343] 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 in the fuel cell. FuelCell Energy, Inc. (2018). *SureSource Capture. https://www.fuelcellenergy.com/recovery-2/suresource-capture/.*

[344] 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.*

[345] 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.*

[346] 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.*

[347] 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.*

[348] 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.*

[349] National Energy Technology Laboratory (NETL), ''FE/NETL CO2 Saline Storage Cost Model (2017),'' U.S. Department of Energy, DOE/NETL–

Continued

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.[350]

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.[351] 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.[352] 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.[353] The IRA increases and extends the IRC section 45Q tax credit, discussed next.

2018–1871, 30 September 2017. *https://netl.doe.gov/energy-analysis/details?id=2403.*

[350] Details on CO_2 transportation and sequestration costs can be found in the *GHG Mitigation Measures for Steam Generating Units* TSD.

[351] 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.*

[352] Department of Energy. ''Regional Direct Air Capture Hubs.'' (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[353] For more information, see the NETL announcement. *https://www.netl.doe.gov/node/12405.*

(3) 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.

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 proposals 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 explicitly stated that the EPA should consider the tax credit to reduce 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).[354]

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). 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. Therefore, the EPA assumes that investors maximize the value of the IRC section 45Q tax credit at $85/metric ton by meeting those requirements.

(4) Total Costs of CCS

In a typical NSPS analysis, the EPA amortizes costs over the expected life of

[354] 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).

the affected facility and assumes constant revenue and expenses over that period of time. This analysis is different because the IRC section 45Q tax credits for the sequestration of CO_2 are only available for combustion turbines that commence construction by the end of 2032 and are available for 12 years. The construction timeframe is within the NSPS review cycle, and the EPA has determined that it is appropriate to include the credits as part of the CCS costing analysis. 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 assuming a 30-year useful life and a separate analysis assuming the capital costs are amortized over a 12-year period. For the 30-year analysis, the EPA used a discount rate of 3.8 percent for the 45Q tax credits to get an effective 30-year value of $41/ton.

Even considering that the IRC section 45Q tax credits are currently available for only 12 years and would, therefore, only offset costs for a portion of a new NGCC turbine's expected operating life, the current overall CO_2 abatement costs of CCS of a 90 percent capture amine-based post combustion capture system, accounting for the tax credit, are $44/ton ($49/metric ton) and the increase in the LCOE is $15/MWh.[355] These costs assume a stable 30-year operating life, transport, storage, and monitoring costs of $10/metric ton, and do not include any revenues from sale of the CO_2 following the 12-year period when the IRC section 45Q tax credit is available. An alternate costing approach is to assume all capital costs are amortized during the 12-year period when tax credits are available. These tax credits are a significant source of revenue and would lower the incremental generating costs of the unit. Therefore, under the 12-year costing approach the EPA increased the assumed annual capacity factor from 65 to 75 percent. The 12-year CO_2 abatement costs are $19/ton ($21/metric ton) and the increase in the LCOE is $6/MWh. These costs are for a combined cycle unit with a base load rating of 4,600 MMBtu/h with an output of approximately 700 MW.[356] These costs could be higher for small units and lower for larger units. For additional details on the CCS costing analysis see the *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines* TSD, which is available in the rulemaking docket. The EPA is soliciting comment on whether the CCS transport, storage, and monitoring costs are appropriate for determining the BSER costs for combustion turbines.

(5) Comparison to Other Costs of Controls

In assessing cost reasonableness for the BSER determination for this rule, the EPA compares 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. The costs presented in this section of the preamble are in 2019 dollars.[357]

At different times, many coal-fired steam generating units have been required 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 fact that 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 Cross-State Air Pollution Rule (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.[358] In the March 15, 2023 Good Neighbor Plan for the 2015 Ozone NAAQs (2023 GNP), 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.[359] Finally, using current cost equations and assumptions (including a 50 percent annual capacity factor, and otherwise consistent with the 2023 GNP) for retrofitting wet FGD on a representative 700 to 300 MW coal-fired steam generating unit results in annualized costs of $23.20 to $29.00/MWh of generation, respectively.[360]

Finally, the EPA 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).[361] Converted to a ton of CO_2e reduced basis, those costs are expressed as $98/ton of CO_2e reduced.[362]

The costs for CCS applied to a representative new base load stationary combustion turbine EGU are generally lower than the above-described costs, which supports the EPA's view that the CCS costs are reasonable. The CCS costs range from $6 to $15/MWh of generation or $19 to $44/ton of CO_2 reduced (depending on the amortization period).

(C) Non-Air Quality Health and Environmental Impact and Energy Requirements

In this section of the preamble, the EPA explains that it does not expect the use of CCS for new combined cycle combustion turbines to have unreasonable adverse consequences related to non-air quality health and environmental impact and energy requirements to combined cycle combustion turbines. The EPA first discusses energy requirements, and then considers non-GHG emissions impacts

[355] The EPA used 3.76 percent discount factor to levelized the 45Q tax credits to an annual value of $45.4/metric ton. These calculations use a service life of 30 years, an interest rate of 7.0 percent, a natural gas price of $3.69/MMBtu, a capacity factor of 65 percent, and a transport, storage, and monitoring cost of $10/metric ton.

[356] The output of the model combined cycle EGU without CCS is 726 MW. The auxiliary load of CCS reduces the net out to 645 MW.

[357] 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.

[358] For additional details, see *https://www.epa.gov/power-sector-modeling/documentation-integrated-planning-model-ipm-base-case-v410.*

[359] 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.*

[360] Ibid.

[361] 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).

[362] Based on the 100-year global warming potential for methane of 25 used in the GHGRP (40 CFR 98 Subpart A, Table A–1).

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 NGCC will increase the parasitic/auxiliary energy demand and reduce its net power output. A utility that wants to construct an NGCC unit to provide 500 MWe-net of power could build a 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 NGCC plant 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 of the criteria or hazardous 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 or hazardous 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.[363]

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 of them would be mitigated or adequately 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 organic-HAP emissions, and there are likely few, if any, metallic-HAP emissions from combustion of natural gas. 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 may be subject to major NSR requirements for NO_X emissions, which may necessitate the installation of SCR to comply with a control technology determination by the permitting authority. See section XIII.A of this preamble for additional details regarding implications for 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 scrubber 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.[364] [365]

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.[366] 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. 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. Furthermore, the EPA is soliciting comment on additional ways that may be identified to responsibly advance the deployment of CCS and ensure meaningful engagement with local communities.

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 NGCC units require limited amounts of cooling water, the absolute amount of increase in cooling water required due to use of CCS does not present unsurmountable concerns. 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 proposing that the additional cooling water requirements from CCS are reasonable.

As noted in section VII.F.3 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.

(D) Impacts on the Energy Sector

The EPA does not believe that determining CCS to be BSER for base load units will cause reliability concerns, for two independent reasons. First, the EPA is proposing that the costs of CCS are reasonable and comparable to other controls the electric power industry has used without significant effects on reliability. Second, while CCS is adequately demonstrated and cost reasonable, the current proposal allows companies that want to build a base load combined cycle combustion turbine a second pathway to meet its requirements: building a unit that co-fires low-GHG hydrogen in the appropriate amount. In fact, companies are pursing both of these options,

[363] 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.

[364] 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).

[365] 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).

[366] 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 and hydrogen, they may continue to face disproportionate burden. This is discussed further in section XIV.E of this preamble.

including units with CCS, in various stages of development. The EPA also expects there to be considerable interest in building intermediate load and peaker units to meet market 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 (post-IRA 2022 reference case, see section IV.F of the preamble). Finally, combined cycle units are only one of many options that companies have to build new generation. For instance, in 2023, combined cycle units are only expected to represent 14 percent of all new generating capacity built in the US and only a portion of that is natural gas combined cycle capacity.[367] Finally, several companies have recently announced plans to move away from new combined cycle 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 plant it had initially proposed to replace the retiring Sherco coal-fired plant.[368] For these reasons, determining CCS to be the BSER for base load units will not cause reliability concerns.

(E) 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 operating life. Use of CCS would avoid the release of nearly 41 million tons of CO_2 over the operating life of the combined cycle EGU. 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.

(F) 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 supports our BSER determination. A standard of performance based on highly efficient generation in combination with the use of CCS—combined with the availability of 45Q tax credits and investments in supporting CCS infrastructure from the IIJA—should incentivize additional use of CCS, which should incentivize cost reductions through the development and use of better performing solvents or sorbents. While solvent-based CO_2 capture has been adequately demonstrated at the commercial scale, a determination that a component of the BSER for new base load stationary combustion turbine (and long term coal-fired steam generating units) is the use of CCS will also likely incentivize the deployment of alternative CO_2 capture techniques at scale. Moreover, as noted above, the cost of CCS has fallen in recent years and is expected to continue to fall; and further implementation of the technology can be expected to lead to additional cost reductions, due to added experience and cost efficiencies through scaling.

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.[369] 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.

(G) Proposed BSER

The Agency proposes that for new natural gas-fired base load combustion turbines, an efficient stationary combined cycle combustion turbine utilizing CCS at a capture rate of 90 percent, beginning in 2035, qualifies as the BSER because it is adequately demonstrated; it entails reasonable costs taking account of the IRC section 45Q tax credit, it achieves significant emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements, including on a nationwide basis. The fact that it promotes useful technology provides additional, although not essential, support for this proposal.

iv. Low-GHG Hydrogen

As discussed, the EPA is proposing two BSER pathways that new stationary combustion turbines may take—one that is based on the use of 90 percent CCS and a separate BSER pathway based upon co-firing low-GHG hydrogen. In this section, the EPA explains why it believes that CCS could form the basis of the BSER. In section VII.F.3.c, we discuss why we believe burning low-GHG hydrogen could also form the basis of the BSER.

v. Basis for Proposal of a Second Component of BSER, Based on CCS, in 2035

When considering whether a technology should be BSER, the EPA must consider both unit level and nationwide questions. At the unit level, the EPA must ask whether the technology is proven, can be implemented at reasonable cost, and achieves emission reductions without causing other significant environmental or energy issues. With regard to CCS at the unit level, the EPA believes there is ample evidence to conclude that it is available and cost reasonable (with the 45Q tax credits) today, and that a well-sited individual new unit could meet the standard of performance based on the application of 90 percent CCS on the startup date of the facility. However, when looking at the technology from a nationwide basis, the EPA must take larger system-wide impacts into consideration. For CCS, this includes questions about the development and availability of infrastructure for transportation and storage[370] as well as considerations related to the lead time needed to scale manufacturing and the installation of carbon capture equipment to meet the amount of capacity potentially subject to this proposed BSER (in addition to meeting IRA-driven demand for CCS in other sectors).

The EPA considered establishing the start of phase 2 of the standard of performance as early as 2030 on the assumption that projects that commence construction in the period immediately following this rulemaking will need at least that amount of time to implement the BSER. However, the EPA is also

[367] *https://www.eia.gov/todayinenergy/detail.php?id=55419.*

[368] *https://cubminnesota.org/xcel-is-no-longer-pursuing-gas-power-plant-proposes-more-renewable-power/.*

[369] Does not include 114 billion kilowatt hours from natural gas-fired CHP projected in AEO 2023.

[370] For further information on timing associated with CO_2 transport and storage design, engineering, and construction, see *GHG Mitigation Measures for Steam Generating Units* TSD, chapter 4.7.1.

proposing to determine that the BSER for long-term coal-fired steam generating units (those that will be in operation beyond 2040) is the use of 90 percent capture CCS and that the associated standard of performance for those units is effective beginning in 2030. The EPA is also aware that a significant number of new base load combined cycle stationary combustion turbines are projected to be constructed by 2030, and that there are other, non-power sector industries that will also be pursuing implementation of CCS in that timeframe. The EPA believes that while CCS poses low supply chain risk due to the required infrastructure relying on common and readily available raw materials and CCS infrastructure can be supplied in large part by domestic components,[371] the deployment of CCS infrastructure, including the demand for the manufacturing and installation of CCS equipment and CO_2 pipeline infrastructure, and the demand for conducting sequestration site characterization and permitting, should be prioritized for the higher GHG-emitting fleet of existing long-term coal-fired steam generating units. The EPA also understands that many utilities and power generating companies are trying to assess their near-term and long-term base load generating needs and may have useful information to provide to the record that would help to assess the demand for CCS. Therefore, in consideration of these factors, the EPA is proposing that phase 2 of the standard of performance begin in 2035 to ensure achievability of the standard. The EPA also recognizes that commenters may have more information about implementing CCS on a broader scale that would help to assess whether 2030 or 2035 (or somewhere in between) would be an appropriate start date for phase 2 of the standards of performance that are based, in part, on the use of CCS. For this reason, the EPA solicits comment on whether the compliance date for phase 2 of the standards of performance should begin earlier than 2035, including as early as 2030.

c. BSER for Base Load Subcategory of Combustion Turbines Adopting the Low-GHG Hydrogen Co-Firing Pathway and Intermediate Load Subcategory—Second and Third Components

This section describes the second and third components of the EPA's proposed BSER for the subcategory of base load combustion turbines that are adopting the low-GHG hydrogen co-firing pathway and the second component for combustion turbines in the intermediate load subcategory. For both subcategories, the EPA is proposing that the second component of the BSER is co-firing 30 percent (by volume) low-GHG hydrogen and that sources meet a corresponding standard of performance beginning in 2032. For base load combustion turbines in this subcategory of sources that adopt the low-GHG hydrogen co-firing pathway, the EPA is proposing that the third component of the BSER is co-firing 96 percent (by volume) low-GHG hydrogen and that sources meet a corresponding standard of performance beginning in 2038. The EPA is also soliciting comment on whether, in lieu of providing a subcategory for base load combustion turbines that adopt the low-GHG hydrogen co-firing pathway, a single BSER for base load combustion turbines should be selected based on application of CCS with 90 percent capture—which could also be met by co-firing 96 percent (by volume) low-GHG hydrogen. The first part of this section is a background discussion concerning several key aspects of the hydrogen industry as it is currently developing. At the outset, the EPA summarizes the activities of some power producers and turbine manufacturers to develop and demonstrate hydrogen co-firing as a viable decarbonization technology for the power sector. The EPA then discusses the GHG emissions performance of stationary combustion turbines when hydrogen is used as a fuel. This discussion includes the different methods of production and the associated GHG emissions for each. The second part of this section describes the proposed second component of the BSER, which is co-firing 30 percent (by volume) low-GHG hydrogen and the third component of the BSER, which, for certain units, is co-firing 96 percent (by volume) low-GHG hydrogen.

The EPA is also proposing a definition of low-GHG hydrogen. The EPA is proposing that hydrogen qualifies as low-GHG hydrogen if it is produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen (kg CO_2e/kg H_2) on a well-to-gate basis consistent with the system boundary established in IRC section 45V (Credit for Production of Clean Hydrogen) of the IRA. Hydrogen produced by electrolysis (splitting water into hydrogen and oxygen) using non-emitting energy sources such as solar, wind, nuclear, and hydroelectric power, can produce hydrogen with carbon intensities lower than 0.45 kg CO_2e/kg H_2, which could qualify as low-GHG hydrogen for the purposes of this proposed BSER.[372] However, the EPA is also soliciting comment on whether a specific definition of low-GHG hydrogen should be included in the final rule. The third part of this section explains why the EPA proposes that co-firing 30 percent (by volume) low-GHG hydrogen qualifies as a component of the BSER. Co-firing 30 percent (by volume) hydrogen is technically feasible and well-demonstrated in new combustion turbines, it will be supported by an adequate supply of hydrogen by 2032, it will be of reasonable cost, it will ensure reductions of GHG emissions, and it will be consistent with the other BSER factors. The EPA also includes in this section an explanation of why the Agency thinks that highly efficient generating technology combined with co-firing only low-GHG hydrogen is the "best" system of emission reduction, taking into account the statutory considerations. This third part of this section also explains why the EPA proposes that co-firing 96 percent (by volume) low-GHG hydrogen qualifies as a third component of the BSER for base load combustion turbines that are subject to a second phase standard of performance based on co-firing 30 percent (by volume) low-GHG hydrogen. The EPA proposes that co-firing 96 percent (by volume) low-GHG hydrogen is technically feasible and well-demonstrated in new combustion turbines, it will be supported by an adequate supply of low-GHG hydrogen by 2038, it will be of reasonable cost, it will ensure reductions of GHG emissions, and it will be consistent with the other BSER factors.

i. Lower Emitting Fuels

The EPA is not proposing lower emitting fuels as the second component of BSER for base load or intermediate load combustion turbines because it would achieve few emission reductions compared to co-firing low-GHG hydrogen.

ii. Highly Efficient Generation

For the reasons described above, the EPA is proposing that highly efficient generation technology in combination with best operating and maintenance practices continues to be a component of the BSER that is reflected in the

[371] U.S. Department of Energy, Achieving American Leadership in the Carbon Capture, Transport, and Storage Supply Chain, March 23, 2022 (DOE/OP–0001–1). *https://www.energy.gov/sites/default/files/2022-03/Carbon%20Capture%20factsheet.pdf.*

[372] U.S. Department of Energy (DOE). Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://www.energy.gov/articles/doe-releases-new-reports-pathways-commercial-liftoff-accelerate-clean-energy-technologies.*

second phase of the standards of performance for base load turbines that are adopting the low-GHG hydrogen co-firing pathway and intermediate load combustion turbines. Highly efficient generation reduces fuel use as well as the absolute amount and cost of low-GHG hydrogen that would be required to comply with the second phase standards.

iii. CCS

The EPA is not proposing the use of CCS as a component of the BSER for base load turbines combusting that are adopting low-GHG hydrogen co-firing or intermediate load combustion turbines. As described previously, simple cycle technology is the most common combustion turbine technology applicable to the intermediate load subcategory and the Agency is limiting consideration of CCS to base load combined cycle EGUs. Intermediate load combustion turbines tend to start and stop frequently and have relatively short periods of continuous operation. CCS systems could have difficulty starting fast enough to get significant levels of CO_2 capture. The EPA solicits comment on flexible CCS technologies that could be used by intermediate load combustion turbines. In addition, the CCS equipment could essentially remain idle for much of the time while these intermediate units are not running. For these reasons, CCS would be less cost-effective for intermediate load combustion turbine EGUs—particularly at much lower capacity factors—as compared to base load combined cycle units that are not on the pathway to combusting 96 percent (by volume) low-GHG hydrogen.

With respect to base load combustion turbine EGUs, as explained previously, the EPA is proposing two BSER pathways that new base load stationary combustion turbines may take—one that is based on the use of 90 percent CCS and a separate BSER pathway based upon co-firing low-GHG. In this section, the EPA explains why it believes that co-firing with low-GHG hydrogen could form the basis of the BSER. In section VII.C.3.b.iii, we discuss why we believe CCS could also form the basis of the BSER.

iv. Background Discussion of Hydrogen and the Electric Power Sector, Hydrogen Co-Firing in Combustion Turbines, and Hydrogen Production Processes

Hydrogen in the United States is primarily used for refining petroleum and producing fertilizer, with smaller amounts also used in sectors like metals treatment, processing foods, and production of specialty chemicals.[373] In recent years, applications of hydrogen have expanded to include co-firing in combustion turbines used to generate electricity. In fact, many models of existing combustion turbines that are used for electricity generation have successfully demonstrated the ability to co-fire blends of 5 to 10 percent hydrogen by volume without modification to the combustion system. Furthermore, combustion of hydrogen blends as high as 20 to 30 percent by volume are being tested and demonstrated; and new turbine designs that can accommodate co-firing much greater percentages of hydrogen are being developed.

Several power producers made financial investments and began work on hydrogen co-firing projects prior to passage of the IRA in August 2022. For example, in early 2021, the Intermountain Power Agency (IPA) project in Utah began the transition away from operating an 1,800–MW coal-fired steam generating unit to an 840–MW combined cycle combustion turbine that will integrate 30 percent by volume hydrogen co-firing at startup in 2025.[374] IPA and its partners have announced plans to produce low-GHG hydrogen via solar-powered electrolysis with storage in underground geologic formations en route to combusting 100 percent low-GHG hydrogen in the combined cycle unit by 2045. IPA also has agreements to sell its electricity to the Los Angeles Department of Water and Power.

Another example is the Long Ridge Energy Generation Project in Ohio.[375] The 485–MW combined cycle combustion turbine became operational in 2021 and is designed to transition to 100 percent hydrogen in the future.[376] The unit successfully co-fired 5 percent by volume hydrogen in March 2022.[377 378] The planned next step for Long Ridge is to co-fire 20 percent by volume hydrogen with the existing turbine design, which has been commercially available since 2017 and can co-fire 15 to 20 percent by volume hydrogen without modification.[379] Furthermore, in June 2022, Southern Company successfully demonstrated the co-firing of a 20 percent by volume hydrogen blend at Georgia Power's Plant McDonough-Atkinson. The co-firing demonstration was performed on a combustion turbine at partial and full loads and produced a 7 percent reduction in CO_2 emissions.[380] In September 2022, the New York Power Authority (NYPA) successfully co-fired a 44 percent by volume blend of hydrogen in a retrofitted combustion turbine. According to the Electric Power Research Institute (EPRI), the project demonstrated a 14 percent reduction in CO_2 at a 35 percent by volume hydrogen blend. The unit's existing SCR controlled NO_X emissions within permit limits.[381 382 383] We note other projects to develop combustion turbines that co-fire hydrogen in section IV.E of this preamble.

Other power producers have implemented large low-GHG hydrogen plans that integrate multiple elements of their generating assets. In Florida, NextEra announced in June 2022 a comprehensive carbon emissions reduction plan that will eventually convert 16 GW of natural gas-fired generation to operate on low-GHG hydrogen as part of the utility's 2045

[373] U.S. Department of Energy (DOE). National Clean Hydrogen Strategy and Roadmap. September 2022. *https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf.*

[374] Intermountain Power Agency (2022). *https://www.ipautah.com/ipp-renewed/.*

[375] 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.*

[376] McGraw, D. (2021). World science community watching as natural gas-hydrogen power plant comes to Hannibal, Ohio. *Ohio Capital Journal. https://ohiocapitaljournal.com/2021/08/27/world-science-community-watching-as-natural-gas-hydrogen-power-plant-comes-to-hannibal-ohio/.*

[377] McGraw, D. (2021). World science community watching as natural gas-hydrogen power plant comes to Hannibal, Ohio. *Ohio Capital Journal. https://ohiocapitaljournal.com/2021/08/27/world-science-community-watching-as-natural-gas-hydrogen-power-plant-comes-to-hannibal-ohio/.*

[378] Defrank, Robert (2022). *Cleaner Future in Sight: Long Ridge Energy Terminal in Monroe County Begins Blending Hydrogen. https://www.theintelligencer.net/news/community/2022/04/cleaner-future-in-sight-long-ridge-energy-terminal-in-monroe-county-begins-blending-hydrogen.*

[379] Patel, S. (April 22, 2022). First Hydrogen Burn at Long Ridge HA-Class Gas Turbine Marks Triumph for GE. Power. *https://www.powermag.com/nypa-ge-successfully-pilot-hydrogen-retrofit-at-aeroderivative-gas-turbine/.*

[380] Patel, S. (2022). *Southern Co. Gas-Fired Demonstration Validates 20% Hydrogen Fuel Blend. https://www.powermag.com/southern-co-gas-fired-demonstration-validates-20-hydrogen-fuel-blend/.*

[381] Palmer, W., & Nelson, B. (2021). *An H_2 Future: GE and New York power authority advancing green hydrogen initiative. https://www.ge.com/news/reports/an-h2-future-ge-and-new-york-power-authority-advancing-green-hydrogen-initiative.*

[382] Van Voorhis, S. (2021). New York to test green hydrogen at Long Island power plant. *Utility Dive. https://www.utilitydive.com/news/new-york-to-test-green-hydrogen-at-long-island-power-plant/603130/.*

[383] Electric Power Research Institute (EPRI). (2022, September 15). *Hydrogen Co-Firing Demonstration at New York Power Authority's Brentwood Site: GE LM6000 Gas Turbine.* Low Carbon Resources Initiative. *https://www.epri.com/research/products/000000003002025166.*

GHG reduction goal.[384] Also, NextEra's Cavendish NextGen Hydrogen Hub will produce hydrogen with a 25–MW electrolyzer system powered by solar energy and the hydrogen will then be co-fired by combustion turbines at Florida Power and Light's 1.75–GW Okeechobee power plant.[385]

One of the first power producers to invest in hydrogen as a fuel for combustion turbines was Entergy, which reached an agreement with turbine manufacturer Mitsubishi Power in 2020 to develop hydrogen-capable combined cycle facilities that include low-GHG hydrogen production, storage, and transportation components.[386] In October 2022, Entergy and New Fortress Energy announced plans to collaborate on a renewable energy and 120–MW hydrogen production plant in southeast Texas.[387] The partnership includes electricity transmission infrastructure as well as the development of renewable energy resources and the offtake of low-GHG hydrogen. A feature of the agreement is the potential to supply hydrogen to Entergy's Orange County Advanced Power Station, which received approval from the Public Utility Commission of Texas in November 2022.[388] The 1,115–MW power plant will replace end-of-life gas generation with new combined cycle combustion turbines that are ready to co-fire hydrogen with the ability to move to 100 percent hydrogen in the future. Construction will begin in 2023 and the project will be completed in 2026.

Hydrogen 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.[389] These services can enhance the reliability of the power system while facilitating the integration of variable renewable energy resources and supporting decarbonization of the electric grid. Hydrogen has the potential to mitigate curtailment, which is the deliberate reduction of electric output below what could have been produced. Curtailment often occurs when RTOs need to balance the grid's energy supply to meet demand. For example, in 2020, the California Independent System Operator (CAISO) curtailed an estimated 1.5 million MWh of solar generation.[390] Curtailment will likely increase as the capacity of variable generation continues to expand. 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.

Rapid progress is being made, and, due to the demonstrated ability of new and existing combustion turbines to co-fire hydrogen, other utility owners/operators have publicly made long-term commitments to hydrogen co-firing and have identified the technology as a key component of their future operations and GHG reduction strategies. As highlighted by the earlier examples, the outlook expressed by multiple power producers and developers includes a future generation asset mix that retains combustion turbines fired exclusively with hydrogen. Utilities in vertically integrated States and merchant generators in wholesale markets rely on combustion turbines to provide reliable, dispatchable power.

Hydrogen gas released into the atmosphere will also have climate and air quality effects through atmospheric chemical reactions. In particular, hydrogen is known to react with the hydroxyl radical, reducing concentrations of the hydroxyl radical in the atmosphere. Because the hydroxyl radical is important for the destruction of many other gases, a reduction in hydroxyl radical concentrations will lead to increased lifetimes of many other gases—including methane and tropospheric ozone. This means that hydrogen gas emissions can also indirectly contribute to warming through increasing concentrations of methane and ozone. Hydrogen is not a greenhouse gas as defined by the Framework Convention on Climate Change under the IPCC, and its secondary impacts on warming should mitigate over time as methane emissions are controlled. Even as hydrogen scales and much larger volumes are consumed, with the attendant potential for emissions of hydrogen to oxidize in the atmosphere, we expect the benefits of low-GHG hydrogen as part of a BSER pathway to outweigh any such effects in the future.

v. Hydrogen Production Processes and Associated Levels of GHG Emissions

Hydrogen is used in industrial processes, and as discussed previously, in recent years, applications of hydrogen co-firing have expanded to include stationary combustion turbines used to generate electricity. However, at present, nearly all industrial hydrogen is produced via methods that are GHG-intensive. 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 of producing the hydrogen and the GHG emissions associated with each process. The following discussion highlights the primary methods of hydrogen production as well as the sources of energy used during production and the level of GHG emissions that result from each production method. The varying levels of CO_2 emissions associated with hydrogen production are well-recognized, and stakeholders routinely refer to hydrogen on the basis of the different production processes and their different GHG intensities.[391]

More than 95 percent of the dedicated hydrogen currently produced in the U.S. originates from natural gas using steam methane reforming (SMR). This method produces hydrogen by adding steam and heat to natural gas in the presence of a catalyst. Methane reacts with the steam to produce hydrogen, carbon monoxide (CO), and trace amounts of CO_2. Further, the CO byproduct is routed to a second process, known as a water-gas shift reaction, to react with more steam to create additional hydrogen and CO_2. After these processes, the CO_2 is removed from the gas stream, leaving

[384] NextEra Energy (2022). Zero Carbon Blueprint. *https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/NextEraEnergyZeroCarbonBlueprint.pdf.*

[385] Clean Energy Group. *Hydrogen Projects in the U.S. https://www.cleanegroup.org/ceg-projects/hydrogen/projects-in-the-us/.*

[386] Mitsubishi Power Americas. (September 23, 2020). *Mitsubishi Power and Entergy to Collaborate and Help Decarbonize Utilities in Four States. https://power.mhi.com/regions/amer/news/20200923.html.*

[387] Entergy. (October 19, 2022). Entergy Texas and New Fortress Energy partner to advance hydrogen economy in Southeast Texas. *https://www.entergynewsroom.com/news/entergy-texas-new-fortress-energy-partner-advance-hydrogen-economy-in-southeast-texas/.*

[388] Entergy. (November 28, 2022). Entergy Texas receives approval to build a cleaner, more reliable power station in Southeast Texas. *https://www.entergynewsroom.com/news/entergy-texas-receives-approval-build-cleaner-more-reliable-power-station-in-southeast-texas/.*

[389] For example, when the sun is not shining and/or the wind is not blowing.

[390] Walton, R. (August 25, 2021). CAISO forced to curtail 15% of California utility-scale solar in March, 5% last year. Power Engineering. *https://www.power-eng.com/solar/caiso-forced-to-curtail-15-of-california-utility-scale-solar-in-march-5-last-year/#gref.*

[391] Some organizations have developed a convention for labeling each hydrogen production method, based on the GHG emissions associated with each method, according to a color scheme. The color labels are insufficiently specific for the purposes of this proposed rule, so the EPA generally does not refer to hydrogen using this color convention.

almost pure hydrogen.[392] CO_2 emissions are generated from the conversion process itself and from the creation of the thermal energy and steam (assuming the boilers are fueled by natural gas) or external energy sources powering the production process. Because the thermal efficiency of SMR of natural gas is generally 80 percent or less,[393] less overall energy is in the produced hydrogen than in the natural gas required to produce the hydrogen. Therefore, the use of hydrogen produced through SMR in a combustion turbine would consume more natural gas than would have been consumed if the combustion turbine had burned the natural gas directly. Therefore, co-firing hydrogen derived from SMR based on fossil fuels without CCS results in higher overall CO_2 emissions than using the natural gas directly in the EGU.

The GHG emissions from hydrogen production via SMR can be controlled with CCS technology at different points in the production process. There are varying levels of CO_2 capture for different techniques, but typically a range of 65 to 90 percent is viable.[394] The autothermal reforming (ATR) of methane is a similar technology to SMR, but ATR utilizes natural gas in the process itself without an external heat source.[395] CCS can also be applied to ATR.

Another process to produce hydrogen is methane pyrolysis. Methane pyrolysis is the thermal decomposition of methane in the absence (or near absence) of oxygen, which produces hydrogen and solid carbon (*i.e.,* carbon black) as the only byproducts. Pyrolysis uses energy to power its hydrogen production process, and therefore the level of its overall GHG emissions depends on the carbon intensity of its energy inputs. For SMR, ATR, and pyrolysis technologies, emissions from methane extraction, production, and transportation are also significant aspects of their GHG emissions footprints.[396]

In contrast to the three methods discussed above, electrolysis does not use methane as a feedstock. In electrolysis, hydrogen is produced by splitting water into its components, hydrogen and oxygen (O_2), via electricity. During electrolysis, a negatively charged cathode and positively charged anode are submerged in water and an electric current is passed through the water. The result is hydrogen molecules appearing at the negative cathodes and O_2 appearing at the positive anodes. Electrolysis does not emit GHG emissions at the hydrogen production site; the overall GHG emissions associated with electrolysis are instead dependent upon the source of the energy used to decompose the water.[397] According to the DOE, electrolysis powered by fossil fuel energy supplied by the electric grid, based on a national average, would generate overall GHG emissions double those of hydrogen produced via SMR without CCS.[398] [399] However, electrolysis powered by wind, solar, hydroelectric, or nuclear energy is generally considered to lower overall GHG emissions.[400] [401] [402] It should be noted that electrolytic systems utilizing even a small portion of grid-based electricity may not have lower overall GHG emissions and carbon intensities than SMR without CCS.[403] This concern is likely to be mitigated over time as the carbon intensity of the grid declines, given the influx of new renewable generation—the EPA's post-IRA 2022 reference case projects a lower carbon intensity of the grid-—coupled with expected retirements of higher-emitting sources. Naturally occurring hydrogen stored in subsurface geologic formations is also gaining attention as a potential low-GHG source of hydrogen.

vi. The EPA's Proposed BSER and Definition of Low-GHG Hydrogen

The EPA is proposing that the second component of the BSER for new combustion turbines in the relevant subcategories is co-firing 30 percent (by volume) low-GHG hydrogen and that sources meet a corresponding standard of performance by 2032. The EPA is also proposing that new base load combustion turbines that are subject to a standard of performance based on co-firing 30 percent (by volume) low-GHG hydrogen in 2032 must also meet a more stringent standard of performance based on a BSER of co-firing 96 percent (by volume) low-GHG hydrogen by 2038. This section describes the factors the EPA considered in determining what level of co-firing qualifies as a component of the BSER for affected sources and the timing for when that level of co-firing could be technically feasible and of reasonable cost. Key factors informing this determination include the magnitude of CO_2 emission reductions at the combustion turbines, the availability of combustion turbines capable of co-firing hydrogen, potential infrastructure limitations, and access to low-GHG hydrogen.

The relationship between the volume of hydrogen fired and the reduction in CO_2 stack emissions is exponential. At low levels of co-firing there are modest emission reduction benefits, but these reduction benefits amplify as the volume of hydrogen increases due to the lower energy density of hydrogen

[392] U.S. Department of Energy (DOE) (n.d.). Hydrogen Production: Natural Gas Reforming. *https://www.energy.gov/eere/fuelells/hydrogen-production-natural-gas-reforming.* For each kg of hydrogen produced through SMR, 4.5 kg of water is consumed.

[393] Thermal efficiency is the amount of energy in the production (*e.g.,* hydrogen) compared to the energy input to the process (*e.g.,* natural gas). At an efficiency of 80 percent, the product contains 80 percent of the energy input and 20 percent is lost.

[394] Powell, D. (2020). *Focus on Blue Hydrogen.* Gaffney Cline. *https://www.gaffneycline.com/sites/g/files/cozyhq681/files/2021–08/Focus_on_Blue_Hydrogen_Aug2020.pdf.*

[395] ''Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas production regions,'' *Energy Conversion and Management,* February 15, 2022.

[396] In addition, methane extraction operations are known to contribute to air toxics including benzene, ethylbenzene, and n-hexane. *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/basic-information-oil-and-natural-gas.*

[397] Similarly, the overall GHG emissions associated with methane pyrolysis are dependent upon the source of the energy used to decompose the methane and is a key factor to whether it qualifies as low-GHG hydrogen.

[398] DOE (2022). *DOE National Clean Hydrogen Strategy and Roadmap.* Draft—September 2022. *https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf.*

[399] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023: *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB–0329-update.pdf. From the Liftoff report,* ''Carbon intensities are based on data from the Carnegie Mellon Power Sector Carbon Index as well as national averages in grid mix carbon intensity—in some states, grid carbon intensity can be as high as 40 kg CO2e/kg H2.''

[400] U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production: Electrolysis. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.*

[401] For each kg of hydrogen produced through electrolysis, 9 kg of byproduct oxygen are also produced and 9 kg of purified water are consumed. To reduce the cost of hydrogen production, this byproduct oxygen could be captured and sold. For each gallon of water consumed, 0.057 MMBtu of hydrogen is produced. According to the water use requirements for combined cycle EGUs with cooling towers, if this hydrogen is later used to produce electricity in a combined cycle EGU, overall water requirements would be greater than a combined cycle EGU with CCUS.

[402] Electrolysis and other technologies that break apart water to form hydrogen and oxygen consume more water than SMR without CCS. Resource Assessment for Hydrogen Production. National Renewable Energy Laboratory (NREL/TP–5400–77198, July 2020). *https://www.nrel.gov/docs/fy20osti/77198.pdf.* Aside from methane pyrolysis and byproduct hydrogen, other hydrogen production methods consume water during the production process and indirectly due to electricity generation upstream. The moisture present in coal and biomass could be recovered and used in the water gas shift reaction to reduce (or eliminate) water requirements.

[403] U.S. Department of Energy (DOE). Pathways to Commercial Liftoff: Clean Hydrogen. March 2023. *https://www.energy.gov/articles/doe-releases-new-reports-pathways-commercial-liftoff-accelerate-clean-energy-technologies.*

compared to natural gas. For example, co-firing 10 percent hydrogen by volume yields approximately a 3 percent CO_2 reduction at the stack, co-firing 30 percent hydrogen yields a 12 percent CO_2 reduction, co-firing 75 percent hydrogen yields a 49 percent CO_2 reduction, and at 100 percent hydrogen co-firing there are zero CO_2 emissions at the stack.

Importantly, co-firing 30 percent hydrogen by volume is consistent with existing technologies across multiple combustion turbine designs and should be considered a minimal level for evaluation as a system of emission reduction. While all major manufacturers are developing combustion turbines that can co-fire higher volumes of hydrogen, some combustion turbine models are already able to co-fire relatively high percentages.[404] Several currently available new combustion turbine models can burn up to 75 percent hydrogen by volume.[405] Combustion turbine designs capable of co-firing 30 percent hydrogen by volume are available from multiple manufacturers at multiple sizes. As such, a BSER that included co-firing 30 percent hydrogen by volume would not pose challenges for near-term implementation for the EPA's proposed second phase standards beginning in 2032. The EPA is soliciting comment on whether the new and reconstructed combustion turbines will have available combustion turbine designs that would allow higher levels of hydrogen co-firing, such as 50 percent or more by volume by 2030 or 2032. If such combustion turbines are sufficiently available, this would support moving forward the starting compliance date of the second phase of the standards of performance and/or increasing the percent of hydrogen co-firing assumed in establishing the standards.

Because the cost of natural gas is lower than the cost of hydrogen, most new combustion turbines are not, at the present time, designed to burn 100 percent hydrogen when they are placed into service. However, some turbines are available now that can combust 100 percent hydrogen in the future and there is significant evidence that such turbines will be more widely available by the 2030s.[406] Multiple vendors have indicated that they intend to have turbines available that fire 100 percent hydrogen in that timeframe.[407] [408] [409] For example, as noted in section IV.E of this preamble, the LADWP Scattergood Modernization project includes plans to have a hydrogen-ready combustion turbine in place when the 346–MW combined cycle plant (potential for up to 830 MW) begins initial operations in 2029. LADWP foresees the plant running on 100 percent electrolytic hydrogen by 2035.[410] The Intermountain Power Project, also noted in section IV.E of this preamble, commenced construction in 2022 on an 840–MW M501 JAC Mitsubishi Hitachi Power Systems combustion turbine designed to operate using 30 percent (by volume) hydrogen upon startup. The plant is projected to be operational by July 2025 and to transition to 100 percent hydrogen by 2045.[411] Several existing gas turbine technologies are capable of operating with 100 percent hydrogen, including Siemens Energy's SGT–A35 and General Electric's B, E, and F class gas turbines.[412] Comments submitted to the EPA's non-regulatory docket confirm that at the present time, existing units can be retrofitted to operate using 100 percent hydrogen. DOE's National Energy Technology Lab states: Based on data from a literature survey and input from manufacturers, NETL has found that today's modern gas turbines can reliably combust 30–60 percent hydrogen fuels with similar NO_X emissions as compared to their pure natural gas counterparts. Public and private research is underway to produce a 100 percent hydrogen-fueled turbine. NETL anticipates that industry will achieve this technology by around 2030 based on current research progress and publicly announced forecasts.'' [413] Turbine projects that have recently been built and that are currently under construction (such as the Longview turbine and the Intermountain Power Project discussed elsewhere in this preamble) are being developed with the understanding that these technology advances will be retrofittable to these types of turbines. It is worth noting that in many cases, existing turbines are able to co-fire large amounts of hydrogen without significant re-engineering. This is because their burners are developed relatively simply and are able to combust large amounts of hydrogen. In retrospect almost all new turbines are designed with more sophisticated burners that closely control the mixture of air and fuel to maximize efficiency while limiting nitrogen oxide generation. Because hydrogen has very different characteristics than natural gas such as higher flame temperature, these burners need to be re-engineered to accommodate large amounts of hydrogen [414] [415] For more information about the status of combustion turbines with respect to combusting hydrogen see the TSD, ''*Hydrogen in Combustion Turbine EGUs,*'' in the docket for this rulemaking.

Access to low-GHG hydrogen, however, is also an important component of the BSER analysis. Midstream infrastructure limitations and the adequacy and availability of hydrogen storage facilities currently present obstacles and increase prices for delivered low-GHG hydrogen. This is part of the rationale for why the EPA is not proposing hydrogen co-firing as part of the first component of the BSER. Moving gas via pipeline tends to be the least expensive transport and today there are 1,600 miles of dedicated hydrogen pipeline infrastructure.[416] As noted later in a section of this preamble, based on industry announcements, many electrolytic hydrogen production projects will be sited near existing

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[404] Mitsubishi Power Americas. *https://power.mhi.com/special/hydrogen/article_1*.

[405] Overcoming technical challenges of hydrogen power plants for the energy transition. *https://www.nsenergybusiness.com*.

[406] *https://www.dieselgasturbine.com/news/siemens-energy-explores-gas-turbines-future-in-net-zero-energy-mix/8024799.article*.

[407] Mitsubishi highlights four hydrogen projects at CERAWeek. *https://www.power-eng.com/hydrogen/mitsubishi-power-highlights-four-hydrogen-projects/#gref*.

[408] Constellation Energy Corporation's Comments on EPA Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units Docket ID No. EPA–HQ–OAR–2022–0289. Docket comments noted, ''Retrofits using existing technology are available to achieve 50–100% hydrogen combustion by volume at some generators.''

[409] Siemens Energy to provide hydrogen-capable turbines to back up utility-scale solar installation in Nebraska. *https://press.siemens-energy.com/global/en/pressrelease/siemens-energy-provide-hydrogen-capable-turbines-back-utility-scale-solar-installation*.

[410] *https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf*.

[411] IPP Renewed—Intermountain Power Agency.*ipautah.com*.

[412] ICF. Retrofitting Gas Turbine Facilities for Hydrogen Blending.

[413] National Energy Technology Laboratory, A Literature Review of Hydrogen and Natural GAS Turbines: Current State of the Art With Regard to Performance and NO_X 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*; Department of Energy, National Energy Technology Laboratory, ''Experts Discuss Use of Hydrogen-Fueled Turbines to Drive Clean Energy'' September 15, 2022. *https://netl.doe.gov/node/12058*.

[414] Siemens Energy, ''Ten Fundamentals to Hydrogen Readiness'' September 2022. *https://www.siemens-energy.com/global/en/news/magazine/2022/hydrogen-ready.html*.

[415] General Electric, ''Hydrogen-Fueled Gas Turbines'' *https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-overview.pdf*.

[416] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf*.

infrastructure and, in certain cases, will provide combustion turbines access to supply and delivery solutions. Hydrogen blending into existing natural gas pipelines presents another mode of transport and distribution that is actively in use in Hawaii and under exploration in other areas of the country.[417] On-road distribution methods include gas-phase trucking and liquid hydrogen trucking, the latter requiring cooling and compression prior to transport. Different regional distribution solutions may emerge initially in response to localized hydrogen demand.

Gaseous and liquified hydrogen storage technologies are developing, along with lined hard rock storage and limited but promising geologic salt cavern storage. Increased storage capacity and market demand for low-GHG hydrogen is anticipated in response to Federal H2Hub investments as low-GHG hydrogen develops from a localized fuel into a national commodity.

Given the growth in the hydrogen sector and Federal funding for the H2Hubs, which will explicitly explore and incentivize hydrogen distribution, the EPA therefore believes hydrogen distribution and storage infrastructure will not present a barrier to access for new combustion turbines opting to co-fire 30 percent low-GHG hydrogen by volume in 2032 and to co-fire 96 percent low-GHG hydrogen by volume in 2038. The EPA is soliciting comment on the expected low-GHG hydrogen availability by those dates. The EPA is also soliciting comment on whether hydrogen infrastructure is likely to be sufficiently developed by 2030 to provide access to low-GHG hydrogen for new and reconstructed combustion turbines. If so, this would support moving forward the compliance date of the second phase of the standards of performance and/or increase the percent of hydrogen co-firing assumed in establishing the standards.

Whether there will be sufficient volumes of low-GHG hydrogen for new sources to co-fire 30 percent by volume between 2030 and 2032 and then for some base load sources to co-fire 96 percent by 2038 will depend on the deployment of additional low-GHG electric generation sources, the growth of electrolyzer capacity, and market demand. Along with the power sector, the industrial and transportation sectors are also advancing hydrogen-ready technologies. Industries and policymakers in those sectors are actively planning to use hydrogen to drive decarbonization. For the industrial sector where hydrogen is a chemical input to the process or a replacement for liquid fuels, multiple projection pathways are being considered as approaches to lower the GHG intensity of these sectors. The production pathways for the industrial sector include, but are not limited to, fossil-derived hydrogen in combination with CCS. However, due to thermodynamic inefficiencies in using hydrogen to produce electricity, it is likely that only a specific type of low-GHG hydrogen will be used in the power sector. Announcements of co-firing applications support this assertion, and as discussed in another section of this preamble, the power sector is already focused on utilizing low-GHG hydrogen, electricity generators are likely to have ample access to low-GHG hydrogen and in sufficient quantities to support 30 percent co-firing by 2032 and 96 percent by 2038. The DOE's estimates of clean hydrogen production volumes of 10 MMT by 2030 and 20 MMT by 2040, referenced throughout this rulemaking, do not apportion which type of hydrogen is likely to be produced, just that it is 'clean.'[418] The available credits for the lowest GHG hydrogen production tier under IRC section 45V tax subsidies going into effect in 2023, as outlined in another section of this preamble, are three times higher than the credit values allotted for other hydrogen production tiers in IRC section 45V. This incentive can be combined with additional monetization access through direct pay and transferability, and therefore has the potential to drive significant volumes of electrolytic hydrogen, which is likely to be considered as low-GHG hydrogen in this proposal.[419] The EPA's hydrogen co-firing BSER proposal, if finalized, would create a significant additional demand driver for electrolytic hydrogen not considered in the DOE's hydrogen production goals of 10 MMT by 2030 and 20 MMT by 2040. Indeed, high volumes of electrolytic hydrogen were central to pathways enabling the power sector to achieve net-zero emissions by 2035 according to analysis by the National Renewable Energy Laboratory (NREL).[420] These incentives will be multiplied by investments through the DOE's H2Hub program. Electrolytic production costs, inclusive of the 45V PTC, are estimated to fall to less than \$0.40/kg by 2030; this could translate to delivered cost of hydrogen for combustion turbines in 2030 between \$0.70/kg and \$1.15/kg depending on storage and distribution costs.[421] The EPA is soliciting comment on whether sufficient quantities of low-GHG hydrogen are likely to be available at reasonable costs by 2030. If so, this would support moving forward the compliance date of the second component of the BSER and/or increase the percent of hydrogen co-firing assumed in establishing the standard of performance.

As discussed earlier, an important feature of hydrogen as a potential fuel for combustion turbines is the level of GHG emissions generated during the production process, with different processes resulting in different levels of GHG emissions. The EPA proposes to conclude that co-firing with low-GHG hydrogen (but not other forms of hydrogen) appropriately considers the statutory factors and constitutes the ''best'' system of emission reduction. Here, the EPA discusses the proposed definition of low-GHG hydrogen. In the IIJA and IRA, Congress established programs to support the development of low-GHG hydrogen, including section 40314 of the IIJA which established a \$8 billion Clean Hydrogen Hubs H2Hubs program, the \$500 million Clean Hydrogen Manufacturing and Recycling Program, and a \$1 billion Clean Hydrogen Electrolysis Program to further electrolysis development. Section 40315 of the IIJA required DOE to establish a non-regulatory Clean Hydrogen Production Standard (CHPS). Most recently, in the IRA, section 13204, Congress authorized the clean hydrogen production tax credit (45V). Several Federal agencies, including the EPA, are implementing those programs. DOE consulted the EPA while developing its proposed CHPS, which included examining various hydrogen production processes and the spectrum of resulting overall carbon intensities.

[417] *https://www.hawaiigas.com/clean-energy/decarbonization.*

[418] DOE, as required by the IIJA, proposed a Clean Hydrogen Production Standard (CHPS) of having an overall emissions rate of 4 kg CO_2e/kg H_2. CHPS is not an actual standard, rather a non-binding tool for DOE's internal use with selecting projects under the H2Hubs program. DOE's proposed CHPS can be found at *https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf.*

[419] ''The Hydrogen Credit Catalyst: How US Treasury guidance on a new tax credit could shape the clean hydrogen economy, the future of American industry, and orient the power sector for full decarbonization,'' Rocky Mountain Institute, February 27, 2023.

[420] Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. Golden, CO: National Renewable Energy Laboratory. NREL/TP[1]6A40–81644. *https://www.nrel.gov/docs/fy22osti/81644.pdf.*

[421] U.S. Department of Energy (DOE). Pathways to Commercial Liftoff: Clean Hydrogen. March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.*

That collaborative process provided useful points of reference for the EPA to use in proposing a definition in this rulemaking.

In enacting the IRA, Congress recognized that different methods of hydrogen production generate different amounts of GHG emissions and sought to encourage lower-emitting production methods through the multi-tier hydrogen production tax credit (IRC section 45V). The IRC section 45V tax credits provide four tiers of tax credits, and thus award the highest amount of tax credits to the hydrogen production processes with the lowest estimated GHG emissions. The highest tier of the credits is \$3/kg H_2 for 0.0 to 0.45 kg CO_2e/kg H_2 produced, and the lowest is \$0.6/kg H_2 for 2.5 to 4.0 kg CO_2e/kg H_2.[422] Congress also provided a definition of ''clean hydrogen'' in section 822 of the IIJA. This provision sets out a non-binding goal intended for use in development of the DOE's Clean Hydrogen Production Standard (CHPS) and DOE's funding programs to promote promising new hydrogen technologies.

Several Federal agencies are engaging in low-GHG hydrogen-related efforts, some of which implement the IRA and IIJA provisions. As discussed earlier in this section, the DOE is working on a Clean Hydrogen Production Standard,[423] an \$8 billion Clean Hydrogen Hub solicitation,[424] and several hydrogen-related research and development grant programs.[425] The Department of the Treasury is taking public comment on examining appropriate parameters for evaluating overall emissions associated with hydrogen production pathways as it prepares to implement IRC section 45V.[426] Within the EPA, there are rulemaking efforts that could impact low-GHG hydrogen production pathways, namely the proposed and supplemental oil and gas emission guidelines to reduce methane emissions.

The IIJA includes both a textual definition of ''clean hydrogen'' and requires the DOE to develop a Clean Hydrogen Production Standard: these two references are related but distinct. Upon review of the reference points that these legislative provisions and Agency programs provide, it is apparent that the clean hydrogen definition in section 822 of the IIJA is not appropriate for the purposes of this rule. As noted, this provision sets a non-binding goal for use in the development of the DOE's Clean Hydrogen Production Standard (CHPS) and the DOE's funding programs to promote promising new hydrogen technologies. The definition of clean hydrogen in the IIJA is limited to GHGs emitted at the hydrogen production site and is therefore not intended to consider overall GHG emissions associated with that production method. According to the IIJA, clean hydrogen as defined as part of the CHPS is ''. . . hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide-equivalent produced *at the site of production* per kilogram of hydrogen produced'' (emphasis added). A significant portion of the GHG emissions associated with hydrogen derived from natural gas originates from upstream methane emissions, which are not accounted for in the CHPS definition.[427] That definition was taken into consideration, along with multiple other data points, for development of the CHPS. In CHPS draft guidance, a target of 4 kg CO_2e/kg H_2 on a well-to-gate basis, which aligns with full range of the IRC section 45V definition in the IRA.[428]

In contrast, the EPA believes that the highest tier of the IRC section 45V(b)(2) production tax credit is salient for purposes of the present rule. That provision provides the highest available amount of production tax credit for hydrogen produced through a process that has a GHG emissions rate of 0.45 kg CO_2e/kg H_2 or less, from well-to-gate. As explained further below, the EPA proposes that co-firing hydrogen that meets this criterion qualifies as a component of the ''best'' system of emission reduction, taking into account the statutory considerations. Thus, consistent with the tiered approach and system boundaries in the IRA definition of clean hydrogen, the EPA is proposing that low-GHG hydrogen is hydrogen that is produced through a process that has a GHG emissions rate of 0.45 kg CO_2e/kg H_2 or less, from well-to-gate. Each of the subsequent hydrogen production categories outlined in 45V(b)(2) convey increasingly higher amounts of GHG emissions (from a well-to-gate analysis), making them less suitable to be a component of the BSER.

Electrolyzers with various low-GHG energy inputs, like solar, wind, hydroelectric, and nuclear, appear most likely to produce hydrogen that would meet the 0.45 kg CO_2e/kg H_2 or less, from well-to-gate criteria.[429] Hydrogen production pathways using methane as a feedstock induce upstream methane emissions associated with extraction, production, and transport of the methane. SMR and ATR also release heating and process-related CO_2 emissions that are difficult to capture at high rates economically. High contributions to overall GHG emission rates may disqualify certain hydrogen production pathways from producing low-GHG hydrogen. The EPA recognizes that the pace and scale of government programs and private research suggest that we will gain significant experience and knowledge on this topic during the timeframe of this proposed rulemaking. Accordingly, the EPA is soliciting comment broadly on its proposed definition for low-GHG hydrogen, and on alternative approaches, to ensure that co-firing low-GHG hydrogen minimizes GHG emissions, and that combustion turbines subject to this standard utilize only low-GHG hydrogen.

The EPA is also taking comment on whether it is necessary to provide a definition of low-GHG hydrogen in this rule. 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 standards for this rule, low-GHG hydrogen may be the most common source of hydrogen available for electricity production. 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. These power suppliers include NextEra, Los Angeles Department of Power and Water, and New York Power Authority, as discussed earlier in this section. Many utilities and merchant generators own nuclear, wind, solar, and hydroelectric generating sources as well as combustion turbines. The EPA has identified an emerging trend in which energy companies with this broad collection of generation assets are planning to produce low-GHG hydrogen for sale and to use a portion of it to fuel their stationary combustion turbines. This emerging trend lends support to the view that the power sector is likely

[422] These amounts assume that wage and apprenticeship requirements are met.

[423] 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*.

[424] *https://www.energy.gov/oced/regional-clean-hydrogen-hubs*.

[425] *https://www.hydrogen.energy.gov/funding_opportunities.html*.

[426] *https://home.treasury.gov/news/press-releases/jy0993*.

[427] Infrastructure Investment and Jobs Act of 20211Law PUBL058.PS (*https://www.congress.gov*).

[428] U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance

[429] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB–0329-update.pdf*.

to have access to and will choose to utilize low-GHG hydrogen for its co-firing applications. Some NGOs have expressed concern that existing non-emitting assets will channel electricity from the grid toward electrolyzers, potentially increasing marginal electricity generation from assets with higher carbon intensities. The EPA agrees these are important issues that should be considered as levels of excess zero carbon-emitting generation vary diurnally and by region. The EPA notes that these concerns should mitigate over time as the carbon intensity of the grid is projected to decline.

Moreover, by the next decade, costs for low-GHG hydrogen are expected to be competitive with higher-GHG forms of hydrogen given declines due to learning and the IRC section 45V subsidies. Given the tax credits in IRC section 45V(b)(2)(D) of \$3/kg H_2 for hydrogen with GHG emissions of less than 0.45 kg CO_2e/kg H_2, and substantial DOE grant programs to drive down costs of clean hydrogen, some entities project the delivered costs of electrolytic low-GHG hydrogen to range from \$1/kg H_2 to \$0/kg H_2 or less.[430 431 432] These projections are more optimistic than, but still comparable to, DOE projections of 2030 for delivered costs of electrolytic low-GHG hydrogen in the range of \$0.70/kg to \$1.15/kg for power sector applications, given R&D advancements and economies of scale.[433] A growing number of studies are demonstrating more efficient and less expensive techniques to produce low-GHG electrolytic hydrogen; and, tax credits and market forces are expected to accelerate innovation and drive down costs even further over the next decade.[434 435 436] The combination of competitive pricing and widespread net-zero commitments throughout the utility and merchant electricity generation market has the potential to drive future hydrogen co-firing applications to be low-GHG hydrogen.[437] The EPA is therefore soliciting comment on whether low-GHG hydrogen needs to be defined as part of the BSER in this proposed rulemaking.

vii. Justification for Proposing 30 Percent Co-Firing Low-GHG Hydrogen and 96 Percent Co-Firing Low-GHG Hydrogen as Components of the BSER

The EPA is proposing that co-firing 30 percent low-GHG hydrogen, as proposed to be defined above, by new combustion turbines in the relevant subcategories, by 2032, meets the requirements under CAA section 111(a)(1) to qualify as a component of the BSER. Similarly, the EPA is proposing that co-firing 96 percent low-GHG hydrogen by new base load combustion turbines in the relevant subcategory, by 2038, also meets the requirements under CAA section 111(a)(1) to qualify as a component of the BSER. As discussed below, co-firing 30 percent low-GHG hydrogen is adequately demonstrated because it is feasible and well-demonstrated for new combustion turbines to co-fire that percentage of hydrogen and multiple combustion turbine vendors have targets to have 100 percent hydrogen-capable combustion turbines available by around 2030 and are selling combustion turbines today with the intention of those combustion turbines being retrofittable to 100 percent hydrogen firing.[438 439] Several project developers have announced plans to transition from lower levels of co-firing up to firing with 100 percent hydrogen.

The EPA proposes that co-firing 30 percent low-GHG hydrogen by 2032 and 96 percent by 2038 qualify as a BSER pathway for new baseload combustion turbines. For the reasons discussed next, the EPA proposes that co-firing low-GHG hydrogen on that pathway is adequately demonstrated in light of the capability of combustion turbines to co-fire hydrogen and the EPA's reasonable expectation that adequate quantities of low-GHG hydrogen will be available by 2032 and 2038 and at reasonable cost. Moreover, combusting hydrogen will achieve reductions because it does not produce GHG emissions and will not have adverse non-air quality health or environmental impacts or energy requirements, including on the nationwide energy sector. Because the production of low-GHG hydrogen generates the fewest GHG emissions, the EPA proposes that co-firing low-GHG hydrogen, and not other types of hydrogen, qualifies as the ''best'' system of emission reduction. The fact that co-firing low GHG hydrogen creates market demand for, and advances the development of, low-GHG hydrogen, a fuel that is useful for reducing emissions in the power sector and other industries, provides further support for this proposal.

(A) Adequately Demonstrated

As part of the present rulemaking, the EPA evaluated the ability of new combustion turbines to operate with certain percentages (by volume) of hydrogen blended into their fuel systems. This evaluation included an analysis of the technical challenges of co-firing hydrogen in a combustion turbine EGU to generate electricity. The EPA also evaluated available information to determine if adequate quantities of low-GHG hydrogen can be reasonably expected to be available for combustion turbine EGUs by 2032.

Although industrial combustion turbines have been burning byproduct fuels containing large percentages of hydrogen for decades, utility combustion turbines have only recently begun to co-fire smaller amounts of hydrogen as a fuel to generate electricity. The primary technical challenges of hydrogen co-firing are related to certain physical characteristics of the gas. When hydrogen fuel is combusted, it produces a higher flame speed than the flame speed produced with the combustion of natural gas; and hydrogen typically combusts at a faster rate than natural gas. When the combustion speed is faster than the flow rate of the fuel, a phenomenon known as ''flashback'' can occur, which can lead to upstream complications.[440] Hydrogen also has a higher flame temperature and a wider flammability range compared to natural gas.[441]

The industrial combustion turbines currently burning hydrogen are smaller than the larger utility combustion turbines and use diffusion flame combustion, often in combination with water injection, for NO_X control. While

[430] ''US green hydrogen costs to reach sub-zero under IRA: longer-term price impacts remain uncertain,'' S&P Global Commodity Insights, September 29, 2022.

[431] ''DOE Funding Opportunity Targets Clean Hydrogen Technologies'' American Public Power, January 31, 2023.

[432] With the 45V PTC, delivered costs of hydrogen are projected to fall in the range of \$0.70/kg to \$1.15/kg for power sector applications.

[433] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.*

[434] ''Sound waves boost green hydrogen production,'' Power Engineering, January 4, 2023.

[435] ''Direct seawater electrolysis by adjusting the local reaction environment of a catalyst,'' Nature Energy, January 30, 2023.

[436] *https://h2new.energy.gov/.*

[437] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.*

[438] *https://www.powermag.com/first-hydrogen-burn-at-long-ridge-ha-class-gas-turbine-marks-triumph-for-ge/.*

[439] *https://www.doosan.com/en/media-center/press-release_view?id=20172449.*

[440] Inoue, K., Miyamoto, K., Domen, S., Tamura, I., Kawakami, T., & Tanimura, S. (2018). *Development of Hydrogen and Natural Gas Co-firing Gas Turbine.* Mitsubishi Heavy Industries Technical Review. Volume 55, No. 2. June 2018.*https://power.mhi.com/randd/technical-review/pdf/index_66e.pdf.*

[441] Andersson, M., Larfeldt, J., Larsson, A. (2013). *Co-firing with hydrogen in industrial gas turbines. http://sgc.camero.se/ckfinder/userfiles/files/SGC256(1).pdf.*

water injection requires demineralized water and is generally only a NO_X control option for simple cycle turbines, existing simple cycle combustion turbines have successfully demonstrated that relatively high levels of hydrogen can be co-fired in combustion turbines using diffusion flame and supports the EPA's proposal to determine that co-firing 30 percent hydrogen is technically feasible for new base load and intermediate load stationary combustion turbine EGUs by 2032 and that co-firing higher levels—up to 96 percent by volume—is feasible by 2038. The EPA solicits comment on these proposed findings.

The more commonly used NO_X combustion control for base load combined cycle turbines is dry low NO_X (DLN) combustion. Even though the ability to co-fire hydrogen in combustion turbines that are using DLN combustors to reduce emissions of NO_X is currently more limited, all major combustion turbine manufacturers have developed DLN combustors for utility EGUs that can co-fire hydrogen.[442] Moreover, the major combustion turbine manufacturers are designing combustion turbines that will be capable of combusting 100 percent hydrogen by 2030, with DLN designs that assure acceptable levels of NO_X emissions.[443 444] Several developers have announced installations with plans to initially co-fire lower percentages of low-GHG hydrogen by volume before gradually increasing their co-firing percentages—to as high as 100 percent in some cases—depending on the pace of the anticipated expansion of low-GHG hydrogen production processes and associated infrastructure. The goals of equipment manufacturers and the fact that existing combined cycle combustion turbines have successfully demonstrated the ability to co-fire various percentages of hydrogen supports the EPA's proposal to determine that co-firing 30 percent hydrogen is technically feasible for new base load stationary combustion turbine EGUs by 2032 and that co-firing 96 percent hydrogen is technically feasible for new base load stationary combustion turbine EGUs by 2038.

The combustion characteristics of hydrogen can lead to localized higher temperatures during the combustion process. These ''hotspots'' can increase emissions of the criteria pollutant NO_X.[445] NO_X emissions resulting from the combustion of high percentage by volume blends of hydrogen are also of concern in many regions of the country. For turbines using diffusion flame combustion, water or steam injection is used to control emissions of NO_X. The level of water injection can be varied for different levels of NO_X control and adjustments can be made to address any potential increases in NO_X that would occur from co-firing hydrogen in combustion turbines using diffusion flame combustion. As stated previously, all major combustion turbine manufacturers have developed DLN combustors for utility EGUs that can co-fire hydrogen and are designing combustion turbines that will be capable of combusting 100 percent hydrogen by 2030, with DLN designs that assure acceptable levels of NO_X emissions. In addition, EGR in diffusion flame combustion turbines reduces the oxygen concentration in the combustor and limits combustion temperatures and NO_X formation. Furthermore, while combustion controls can achieve low levels of NO_X, many new intermediate load and base load combustion turbines using DLN combustion also use selective catalytic reduction (SCR) to reduce NO_X emissions even further. The design level of control from SCR can be tied to the exhaust gas concentration. At higher levels of incoming NO_X, either the reagent injection rate can be increased and/or the size of the catalyst bed can be increased.[446] The EPA has concluded that any potential increases in NO_X emissions do not change the Agency's view that on balance, co-firing low-GHG hydrogen qualifies as a component of the BSER.

As noted above, at present, most of the hydrogen produced in the U.S. is produced for the industrial sector through SMR, which is a high GHG-emitting process. Limited quantities of hydrogen are currently being produced via SMR with CCS, which reduces some, but not all, of the associated GHG-emitting processes. Only small-scale facilities are currently producing hydrogen through electrolysis with renewable or nuclear energy, and as described below, much larger facilities are under development.

However, as also noted above, incentives in recent Federal legislation are anticipated to significantly increase the availability of low-GHG hydrogen by 2032, including for the utility power sector. The IIJA, enacted in 2021, allocated more than $9 billion to the DOE for research, development, and demonstration of low-GHG hydrogen technologies and the creation of at least four regional low-GHG hydrogen hubs. The DOE has indicated its intention to fund between six and 10 hubs.[447] In addition, the IRA provided significant incentives to invest in low-GHG hydrogen production (For additional discussion of the IIJA and/or IRA, see section IV.E of this preamble.)

Programs from the IIJA and IRA have been successful in prompting the development of new low-GHG hydrogen projects and infrastructure. As of August 2022, 374 new projects had been announced that would produce 2.2 megatons (Mt) of low-GHG hydrogen annually, which represents a 21 percent increase over current output.[448] Examples include:

- In June 2022, the DOE issued a $504.4 million loan guarantee to finance Advanced Clean Energy Storage (ACES), a low-GHG hydrogen production and long-term storage facility in Delta, Utah.[449] The facility will use 220 MW of electrolyzers powered by renewable energy to produce low-GHG hydrogen. The hydrogen will be stored in salt caverns and serve as a long-term fuel supply for the combustion turbine at the Intermountain Power Agency (IPA) project, which is described earlier in this section.
- In January 2023, NextEra announced an 800–MW solar project in the central U.S. to support the development of low-GHG hydrogen as well as plans to produce its own low-

[442] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. *https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/.*

[443] Simon, F. (2021). *GE eyes 100% hydrogen-fueled power plants by 2030. https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.*

[444] Patel, S. (2020). *Siemens' Roadmap to 100% Hydrogen Gas Turbines. https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/.*

[445] Guarco, J., Langstine, B., Turner, M. (2018). *Practical Consideration for Firing Hydrogen Versus Natural Gas.* Combustion Engineering Association. *https://cea.org.uk/practical-considerations-for-firing-hydrogen-versus-natural-gas/.*

[446] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. *https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/.*

[447] IIJA authorized a total of $9.5B for hydrogen related programs ($8 billion for Clean Hydrogen Hubs H2Hubs, $1B for electrolyzer research and development and $500 million for hydrogen-related manufacturing incentives). See also: U.S. Dept. of Energy, Regional Clean Hydrogen Hubs. *https://www.energy.gov/oced/regional-clean-hydrogen-hubs.*

[448] Energy Futures Initiative (February 2023). *U.S. Hydrogen Demand Action Plan. https://energyfuturesinitiative.org/reports/.*

[449] U.S. Department of Energy (DOE). (2022). Loan Office Programs. Advanced Clean Energy Storage. *https://www.energy.gov/lpo/advanced-clean-energy-storage.*

GHG hydrogen at a facility in Arizona.[450]

• In New York, Constellation (formerly Exelon Generation) is exploring the potential benefits of integrating onsite low-GHG hydrogen production, storage, and usage at its Nine Mile Point nuclear station. The project is funded by a DOE grant and includes partners such as Nel Hydrogen, Argonne National Laboratory, Idaho National Laboratory, and the National Renewable Energy Laboratory. The project is expected to generate an economical supply of low-GHG hydrogen that will be safely captured, stored, and potentially taken to market as a source of power for other purposes, including industrial applications such as transportation.[451]

• Bloom Energy began installation of a 240-kW electrolyzer at Xcel Energy's Prairie Island nuclear plant in Minnesota in September 2022 to produce low-GHG hydrogen. The demonstration project, designed to create ''immediate and scalable pathways'' for producing cost-effective hydrogen, is expected to be operational in 2024 and is also funded with a DOE grant.[452]

• In California, Sempra subsidiary SoCalGas has announced plans to develop the nation's largest hydrogen infrastructure system called ''Angeles Link.'' When operational, the project will provide enough hydrogen to convert up to four natural gas-fired power plants. Developers predict the increased access to hydrogen will also displace 3 million gallons of diesel fuel from heavy-duty trucks.[453] [454]

• In December 2022, Air Products and AES announced plans to build a $4-billion low-GHG hydrogen production facility at the site of a former coal-fired power plant in Texas.[455] [456] The plant is expected to be completed in 2027, and once operational, will produce approximately 200 metric tons of low-GHG hydrogen per day from electrolyzers powered by 1.4 GW of wind and solar energy, as noted earlier. This follows an announcement by Air Products in October 2022 to invest $500 million in a low-GHG hydrogen production facility in New York. This 35 metric-ton-per-day project is also expected to be operational by 2027, and in July 2022, received approval from the New York Power Authority for 94 MW of hydroelectric power.[457]

• The DOE National Clean Hydrogen Strategy and Roadmap identified a plausible path forward for the production of 10 MMT of low-GHG hydrogen annually by 2030, 20 MMT annually by 2040, and 50 MMT annually by 2050.

• The NREL Clean Grid 2035 analysis examined several pathways for the power sector to reach net-zero emissions by 2035: each of those pathways included at least 10 MMT of electrolytic hydrogen by 2035, demonstrating how electrolytic hydrogen technologies support rapid grid decarbonization.[458]

• The H2@Scale is a DOE initiative that brings together stakeholders to advance affordable hydrogen production, transport, storage, and utilization to enable decarbonization and revenue opportunities across multiple sectors.

These legislative actions, utility initiatives, and industrial sector production and infrastructure projects indicate that sufficient low-GHG hydrogen and sufficient distribution infrastructure can reasonably be expected to be available by 2032, when offtake scales after 2030,[459] so that, at a minimum, the majority of new combustion turbines could co-fire low-GHG hydrogen. The EPA specifically solicits comment on whether rural areas and small utility distribution systems (serving 50,000 customers or less) can expect to have access to low-GHG hydrogen. To the extent low-GHG hydrogen might be less available in rural areas compared to areas with higher population densities, the EPA solicits comment if sufficient electric transmission capacity is available, or could be constructed, such that electricity generated from low-GHG hydrogen could be transmitted to these rural areas.

By 2035, substantial additional amounts of renewable energy are expected to be available, which can support the production of low-GHG hydrogen through electrolysis.

(B) Costs

There are three sets of potential costs associated with co-firing hydrogen in combustion turbines: (1) The capital costs of combustion turbines that have the capability of co-firing hydrogen; (2) pipeline infrastructure to deliver hydrogen; and (3) the fuel costs related to production of low-GHG hydrogen.

As stated previously, manufacturers are already developing combustion turbines that can co-fire up to 100 percent hydrogen. Accordingly, this limits the amount of additional costs needed to allow combustion turbines to co-fire 30 percent (by volume) hydrogen and, later, 96 percent (by volume). According to data from EPRI's US–REGEN model, 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.[460] However, the EPA is soliciting comment on what additional costs would be required to ensure that combustion turbines are able to co-fire between 30 to 96 percent (by volume) hydrogen and if there are efficiency impacts from co-firing hydrogen.

With respect to pipeline infrastructure, there are approximately 1,600 miles of dedicated hydrogen pipelines currently operating in the U.S. Existing natural gas infrastructure may be capable of accepting blends of hydrogen with modest investments, but the actual limits will vary depending on pipeline materials, age, and operating conditions. Due to the lower energy density of hydrogen relative to natural gas, the piping required to deliver pure hydrogen would have to be larger, and the material used to construct the piping could need to be specifically designed

450 Penrod, Emma. (January 30, 2023). *NextEra charts path for renewables expansion, but campaign finance allegations loom in the background.* Utility Dive. *https://www.utilitydive.com/news/nextera-renewables-expansion-green-hydrogen-solar-alleged-campaign-finance-violation/641475/.*

451 *https://www.exeloncorp.com/newsroom/Pages/DOE-Grant-to-Support-Hydrogen-Production-Project-at-Nine-Mile-Point.aspx.*

452 *https://www.utilitydive.com/news/bloom-energy-hydrogen-xcel-nuclear-prairie-island/632148/.*

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454 Penrod, Emma. (February 18, 2022). *SoCalGas begins developing 100% clean hydrogen pipeline system.* Utility Dive. *https://www.utilitydive.com/news/socalgas-begins-developing-100-clean-hydrogen-pipeline-system/619170/.*

455 McCoy, Michael. (December 8, 2022). *Air Products plans big green hydrogen plant in U.S.* Chemical and Engineering News. *https://cen.acs.org/energy/hydrogen-power/Air-Products-plans-big-green/100/web/2022/12.*

456 Air Products (December 8, 2022). *Air Products and AES Announce Plans to Invest Approximately $4 Billion to Build First Mega-scale Green Hydrogen Production Facility in Texas. https://www.airproducts.com/news-center/2022/12/1208-air-products-and-aes-to-invest-to-build-first-mega-scale-green-hydrogen-facility-in-texas/.*

457 Air Products (October 6, 2022). *Air Products to Invest About $500 Million to Build Green Hydrogen Production Facility in New York. https://www.airproducts.com/news-center/2022/10/1006-air-products-to-build-green-hydrogen-production-facility-in-new-york.*

458 Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. Golden, CO: National Renewable Energy Laboratory NREL/TP[1]6A40–81644. *https://www.nrel.gov/docs/fy22osti/81644.pdf.*

459 DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.*

460 *https://us-regen-docs.epri.com/v2021a/assumptions/electricity-generation.html#new-generation-capacity.*

to be able to handle higher concentrations of hydrogen that would prevent embrittlement and leaks. These risks can be mitigated through deployment of new pipeline infrastructure designed for compatibility with hydrogen in support of a new combustion turbine installation. The majority of announced combustion turbine EGU projects proposing to co-fire hydrogen are located close to the source of hydrogen. Therefore, the fuel delivery systems (*i.e.,* pipes) for new combustion turbines can be designed to transport hydrogen without additional costs. Therefore, the EPA proposes that co-firing rates of 30 percent and up to 100 percent by volume would have limited, if any, additional capital costs for new combustion turbine EGU projects. The EPA is soliciting comment on if additional infrastructure costs, such as bulk hydrogen storage in salt caverns, should be accounted for when determining the costs of hydrogen co-firing.

The primary cost for co-firing hydrogen is the cost of hydrogen relative to natural gas. The cost of delivered hydrogen depends on the technology used to produce the hydrogen and the cost to transport the hydrogen to the end user. For context, the DOE National Clean Hydrogen Strategy and Roadmap cites the current cost of low-GHG electrolytic hydrogen production at approximately $5/kg. The DOE has established a goal of reducing the cost of low-GHG hydrogen production to $1/kg (equivalent to $7.4/MMBtu) by 2030, which is approximately the same as the current production costs of hydrogen from SMR. Using $1/kg (equivalent to $7.4/MMBtu) as the delivered cost of low-GHG hydrogen, co-firing 30 percent (by volume) hydrogen in a combined cycle EGU operating at a capacity factor of 65 percent would increase both the levelized cost of electricity (LCOE) by $2.9/MWh.[461] This is a 6 percent increase from the baseline LCOE. A 96 percent (by volume) co-firing rate increases the LCOE by $21/MWh, a 47 percent increase in the baseline LCOE. Regardless of the level of hydrogen co-firing, the CO_2 abatement cost is $64/ton ($70/metric ton) at the affected facility.[462] For an aeroderivative simple cycle combustion turbine operating at a capacity factor of 40 percent, co-firing 30 percent hydrogen increases the LCOE by $4.1/MWh, representing a 5 percent increase from the baseline LCOE. A 96 percent (by volume) co-firing rate increases the LCOE by $30/MWh, a 31 percent increase in the baseline LCOE.

However, DOE's projected goal of $1/kg production costs (equivalent to $7.4/MMBtu) for low-GHG hydrogen was established prior to the IIJA incentives and IRA tax subsidies for low-GHG hydrogen production, CCS, and generation from renewable sources. These subsidies could be equivalent to, or even exceed, the production costs of low-GHG hydrogen. Even when the cost to transport the hydrogen from the production facility to the end user is accounted for, the cost of low-GHG hydrogen to the end user could be less than $1/kg. Assuming a delivered price of $0.75/kg ($5.6/MMBtu), the CO_2 abatement costs for co-firing hydrogen would be $32/ton ($35/metric ton). For a combined cycle EGU, the LCOE increase would be $1.4/MWh and $11/MWh for the 30 percent and 96 percent (by volume) cases, respectively. For a simple cycle EGU, the LCOE would be $2.1/MWh and $15/MWh for the 30 percent and 96 percent (by volume) cases, respectively. If the delivered cost of low-GHG hydrogen is $0.50/kg ($3.7/MMBtu), this would represent cost parity with natural gas and abatement costs would be zero.

The EPA is proposing to determine that the increase in operating costs from a BSER based on low-GHG hydrogen is reasonable.

(C) Non-Air Quality Health and Environmental Impact and Energy Requirements

The co-firing of hydrogen in combustion turbines in the amounts that the EPA proposes as the BSER would not have adverse non-air quality health and environmental impacts. It would result in NO_X emissions, but those emissions can be controlled, as described in section VII.F.3.c.vii.(A) of this preamble.

In addition, co-firing hydrogen in the amounts proposed would not have adverse impacts on energy requirements, including either the requirements of the combustion turbines to obtain fuel or on the energy sector more broadly, particularly with respect to reliability. As discussed in sections VII.F.3.c.vii.(A)–(B), combustion turbines can be constructed to co-fire high volumes of hydrogen in lieu of natural gas, and the EPA expects that low-GHG hydrogen will be available in sufficient quantities and at reasonable cost. Any impact on the energy sector would be further mitigated by the large amounts of existing generation that would not be subject to requirements in this rule and the projected new capacity in the base case modeling.

(D) Extent of Reductions in CO_2 Emissions

The site-specific reduction in CO_2 emissions achieved by a combustion turbine co-firing hydrogen is dependent on the volume of hydrogen blended into the fuel system. Due to the lower energy density by volume of hydrogen compared to natural gas, an affected source that combusts 30 percent by volume hydrogen with natural gas would achieve approximately a 12 percent reduction in CO_2 emissions versus firing 100 percent natural gas.[463] A source combusting 100 percent hydrogen would have zero CO_2 stack emissions because hydrogen contains no carbon, as previously discussed. A source co-firing 96 percent by volume hydrogen (approximately 89 percent by heat input) would achieve an approximate 90 percent CO_2 emission reduction, which is roughly equivalent to the emission reduction achieved by sources utilizing 90 percent CCS.

(E) Promotion of the Development and Implementation of Technology

Determining co-firing 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent (by volume) to be components of the BSER would generally advance technology development in both the production of low-GHG hydrogen and the use of hydrogen in combustion turbines. This would facilitate co-firing larger amounts of low-GHG hydrogen and facilitate co-firing low-GHG hydrogen in existing combustion turbines. Developing new configurations for flame dimensions and turbine modifications to adjust for the characteristics unique to hydrogen combustion are technology forcing advancements that industry appears to be already leaning into based on the project announcements. Thus, co-firing low-GHG hydrogen fulfills the requirements of BSER to generally advance technology development. In addition, co-firing 30 percent (by volume) low-GHG hydrogen by 2032 would promote additional technology development and infrastructure to facilitate co-firing at higher amounts of low-GHG hydrogen in 2038. As discussed in the preceding section, there are multiple combustion turbine projects planned by industry to co-fire hydrogen initially and progress to firing with 100 percent hydrogen. Fueling combustion turbines with 100 percent hydrogen would eliminate all carbon

[461] The EIA long-term natural gas price for utilities is $3.69/MMBtu.

[462] The abatement cost of co-firing low-GHG hydrogen is determined by the relative delivered cost of the low-GHG hydrogen and natural gas.

[463] The energy density by volume of hydrogen is lower than natural gas.

dioxide stack emissions. It would also promote reliability because it would provide grid operators with asset options, in addition to battery and energy storage, capable of voltage support and frequency regulation. These are asset characteristics that will be required in increasing capacities as more variable generation is deployed.

(F) Basis for Proposing Co-Firing Low-GHG Hydrogen, Not Other Types of Hydrogen, as the ''Best'' System of Emissions Reduction

In this section, the EPA explains further why the type of hydrogen co-fired as a component of the BSER must be limited to low-GHG hydrogen, and not include other types of hydrogen. The EPA explains further the proposed definition of low-GHG hydrogen as 0.45 kg CO_2e/kg H_2 or less from the production of hydrogen, from well-to-gate. Finally, the Agency summarizes the reasons, described above, for the proposal that co-firing 30 percent low-GHG hydrogen meets the criteria under CAA section 111 as the BSER.

(1) Limitation of Co-Firing to Low-GHG Hydrogen

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. Co-firing low-emitting fuels—sometimes referred to as clean fuels—is a traditional type of emissions control, and recognized as a system of emission reduction under CAA section 111. In *West Virginia* v. *EPA,* the Supreme Court noted that in the EPA's prior CAA section 111 actions, the Agency has treated ''measures that improve the pollution performance of individual sources'' as ''system[s] of emission reduction,'' 142 S. Ct. at 2615,[464] and further noted with approval a statement the EPA made in the Clean Power Plan that ''fuel-switching'' was one of the ''more traditional air pollution control measures.'' 142 S. Ct. at 2611 (quoting 80 FR 64784; October 23, 2015). The EPA has relied on lower-emitting fuels as the BSER in several CAA section 111 rules. See 44 FR 33580, 33593 (June 11, 1979) (coal that undergoes washing prior to its combustion to remove sulfur, so that its combustion emits fewer SO_2 emissions); 72 FR 32742 (June 13, 2007) (same); 80 FR 64510 (October 23, 2015) (natural gas and clean fuel oil). Co-firing hydrogen in a combustion turbine in place of natural gas reduces GHG emissions at the source and therefore plainly qualifies as a ''system of emission reduction.'' This is true even if that phrase is narrowly defined to be limited to controls measures that can be applied at and to the source and that reduce emissions from the source, as the ACE Rule provided, or if it is defined more broadly.[465]

In the present proposal, the EPA recognizes that even though the *combustion* of hydrogen is zero-GHG emitting, its *production* entails a range of GHG emissions, from low to high, depending on the method. As noted in VII.F.3.c.v of this preamble, these differences in GHG emissions from the different methods of hydrogen production are well-recognized in the energy sector, and, in fact, hydrogen is generally characterized by its production method and the attendant level of GHG emissions.

Accordingly, the EPA is proposing to require that to qualify as the ''best'' system of emission reduction, the hydrogen that is co-fired must be low-GHG hydrogen, as defined above. This is because the purpose of CAA section 111 is to reduce pollution that endangers human health and welfare to the extent achievable, CAA section 111(b), through promulgation of standards of performance that reflect the ''best'' system of emission reduction that, taking into account certain factors, is adequately demonstrated. CAA section 111(a)(1). Co-firing hydrogen at combustion turbines when that hydrogen is produced with large amounts of GHG emissions would ultimately result in increasing overall GHG emissions, compared to combusting solely natural gas at the combustion turbine. To avoid this anomalous outcome, in evaluating a ''system of emission reduction'' of co-firing hydrogen, the GHG emissions from producing the hydrogen should be recognized to determine whether co-firing that hydrogen is the ''best'' system of emission reduction, within the meaning of CAA section 111(a)(1). The EPA recognizes that the production of low-GHG hydrogen also results in fewer emissions of other air pollutants, although it also requires the use of more water, compared to other methods of producing hydrogen, in particular, ones involving methane, as discussed in section VII.F.3.c.v of this preamble. All these factors, considered together, point towards co-firing low-GHG hydrogen, and not other types of hydrogen, as the ''best'' system of emission reduction.

D.C. Circuit caselaw supports applying the term ''best'' in this manner. In several cases decided under CAA section 111(a)(1) as enacted by the 1970 CAA Amendments, which did not provide that the EPA must consider non-air quality health and environmental impacts in determining the BSER,[466] the court stated that the EPA must consider whether byproducts of pollution control equipment could cause environmental damage in determining whether the pollution control equipment qualified as the best system of emission reduction. *See Portland Cement Ass'n* v. *Ruckelshaus,* 465 F.2d 375, 385 n.42 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974) (stating that ''[t]he 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''); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 439 (D.C. Cir. 1973) (remanding because the EPA failed to consider ''the significant land or water pollution potential'' from byproducts of air pollution control equipment). The situation here is analogous because a standard that allowed for co-firing with other hydrogen would create more damage (in the form of GHG emissions) than it prevented, the precise problem CAA section 111 is intended to address. Considering the overall emissions impact of the production of fuel used by the affected facility to lower its

[464] As discussed in section V.B.4 of this preamble, the ACE Rule took the position that under CAA section 111(a)(1), a ''system of emission reduction'' must be limited to measures that apply at or to the source. 84 FR 32524 (July 8, 2019).

[465] Co-firing hydrogen in place of fossil fuel (generally, natural gas in a combustion turbine) may be contrasted with co-firing biomass in place of fossil fuel (generally, coal in a steam generating unit). The ACE Rule rejected co-firing biomass as a potential BSER for existing coal-fired steam generating units. The rule explained that co-firing biomass does not meet the definition of a ''system of emission reduction,'' under the ACE Rule's interpretation of that term, because co-firing biomass in place of coal at a steam generating unit does not reduce emissions emitted from that source; rather, any emission reductions rely on accounting for activities that occur upstream. 84 FR 32546 (July 8, 2019). In contrast, as discussed in the accompanying text, co-firing hydrogen in place of natural gas at a combustion turbine achieves emission reductions at the source. For that reason, co-firing hydrogen qualifies as a ''system of emission reduction,'' even as the ACE Rule defined the term. As noted in section V.C.3.a of this preamble, the EPA has proposed to reject that definition as too narrow.

[466] As enacted under the 1970 CAA Amendments, CAA section 111(a)(1) read as follows:

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) the Administrator determines has been adequately demonstrated.

In the 1977 CAA Amendments, Congress revised section 111(a)(1) to incorporate a reference to ''non-air quality health and environmental impacts,'' and Congress retained that phrase in the 1990 CAA Amendments when it revised CAA section 111(a)(1) to read as it currently does.

emissions—here, hydrogen—is consistent with considering the environmental impacts of the byproducts of pollution control technology used by the affected facility to lower its emissions.

In addition, the EPA's proposed determination that co-firing low-GHG hydrogen qualifies as the BSER is supported by the IRA and its legislative history. In the IRA, Congress enacted or expanded tax credits to encourage the production and use of low-GHG hydrogen.[467] In addition, as discussed in section IV.E.1 of this preamble, IRA section 60107 added new CAA section 135, 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). The legislative history of this provision makes clear that Congress anticipated that the EPA could promulgate rules under CAA section 111(b) to ensure GHG emissions reductions from fossil fuel-fired electricity generation. 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone, Jr.). The legislative history goes on to state that ''Congress anticipates that EPA may consider . . . clean hydrogen as [a] candidate[ ] for BSER for electric generating plants. . . .'' *Id.*

Most broadly, proposing that only low-GHG hydrogen qualifies as part of the co-firing BSER is required by the ''reasoned decisionmaking'' that the Supreme Court has long held, including recently in *Michigan* v. *EPA,* 576 U.S. 743 (2015), that ''[f]ederal administrative agencies are required to engage in.'' *Id.* at 751 (internal quotation marks omitted and citation omitted). In *Michigan,* the Court held that CAA section 112(n)(1)(A), which directs the EPA to regulate hazardous air pollutants from coal-fired power plants if the EPA ''finds such regulation is appropriate and necessary,'' must be interpreted to require the EPA to consider the costs of the regulation. The Court explained that if the EPA failed to consider cost, it could promulgate a regulation to eliminate power plant emissions harmful to human health but do so through the use of technologies that ''do even more damage to human health'' than the emissions they eliminate. *Id.* at 752. The Court emphasized, ''No regulation is 'appropriate' if it does significantly more harm than good.'' *Id.* Here, as explained above, permitting EGUs to burn high-GHG hydrogen would ''do even more damage to human health'' than the emissions eliminated and therefore could not be considered ''reasoned decisionmaking.'' *Id.* at 751. Likewise, the Supreme Court has long said that an agency engaged in reasoned decisionmaking may not ignore ''an important aspect of the problem.'' *Motor Vehicles Mfrs. Ass'n* v. *State Farm Auto Ins. Co.,* 463 U.S. 29, 43 (1983). Permitting EGUs to burn high-GHG hydrogen to meet the standard of performance here would ignore an important aspect of the problem being addressed, contrary to reasoned decisionmaking.

The proposed standard of performance that is founded upon a BSER of burning hydrogen and the requirement that owners and operators seeking to burn hydrogen use low-GHG hydrogen are distinct requirements that could function independently. It may not be necessary to require that only low-GHG hydrogen be used to comply for owners and operators choosing this pathway included in the BSER in order to be confident that low-GHG hydrogen will be used to meet the standard. Incentives in the IRA may render production of low-GHG hydrogen less costly than higher-GHG hydrogen at some point, thus pushing the hydrogen market toward low-GHG hydrogen. In addition, the EPA may also initiate a rulemaking to regulate GHG emissions from hydrogen production under section 111 of the CAA. The EPA solicits comment on whether it is necessary to define and require low-GHG in this rulemaking. Similarly, the EPA also solicits 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.

(2) Definition of Low-GHG Hydrogen

As noted in section VII.F.3.c.vi of this preamble, the EPA proposes a definition for low-GHG hydrogen that aligns with the highest of the four tiers of tax credit available for hydrogen production, IRC section 45V(b)(2)(D). Under this provision, taxpayers are eligible for a tax credit of $3 per kilogram of hydrogen that is produced with a GHG emissions rate of 0.45 kg CO_2e/kg H_2 or less, from well-to-gate. This amount is three times higher than the amount for the next tier of credit, which is for hydrogen produced with a GHG emissions rate between 1.5 and 0.45 kg CO_2e/kg H_2, from well-to-gate, IRC section 45V(b)(2)(C); and four and five times higher than the amount for the next two tiers of credit, respectively. IRC section 45V(b)(2)(B), (A). With these provisions, Congress indicated its judgement as to what constitutes the lowest-GHG hydrogen production, and its intention to incentivize production of that type of hydrogen. Congress's views inform the EPA's proposal to define low-GHG hydrogen for purposes the BSER for this CAA section 111 rulemaking consistent with IRC section 45V(b)(2)(D).

It should be noted that the EPA is not proposing that the ''clean hydrogen'' definition in section 822 of the IIJA is appropriate for the EPA's regulatory purposes. This definition is designed for a non-regulatory purpose. It sets out a non-binding goal, not a standard or a regulatory definition, intended for use in development of the DOE's CHPS and funding programs to promote promising new hydrogen technologies.

For the reasons discussed above, co-firing low-GHG hydrogen qualifies as the BSER because it is adequately demonstrated, is of reasonable cost, does not have adverse non-air quality health or environmental impacts or energy requirements—in fact, it offers potential benefits to the energy sector—and reduces GHG emissions. The fact that this control promotes the advancement of hydrogen co-firing in combustion turbines provides additional support for proposing it as part of the BSER. Finally, Congress's direction to choose the ''best'' system of emissions reduction and principles of reasoned decision-making dictate that the standard should be based on burning low-GHG hydrogen, and not using other forms of hydrogen.

4. Other Options for BSER

The EPA considered several other systems of emission reduction as candidates for the BSER for combustion turbines, but is not proposing them as the BSER. They include CHP and the hybrid power plant, as discussed below.

a. 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

[467] 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).

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 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 is not proposing CHP as the BSER.

b. 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 NGCC 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. In a hybrid power plant, the lower quality steam is heated to higher temperatures and pressures in the boiler (or HSRG) 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,[468] 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.[469] 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 NGCC 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 three percent reduction in the overall CO_2 emissions and a one 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 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. The EPA is soliciting comment on updated costs for hybrid power plants and if the use of hybrid power plants could be incorporated as part of the BSER for base load combustion turbines.

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).

The EPA is not proposing hybrid power plants as the BSER because of gaps in the EPA's knowledge about costs, and concerns about the cost-effectiveness of the technology, as noted above.

5. Subcategories

Stationary combustion turbines are defined in the 2015 NSPS to include

[468] EIA, Annual Energy Outlook 2018, February 6, 2018. *https://www.eia.gov/outlooks/aeo/*.

[469] 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).

both simple cycle and combined cycle EGUs. In addition, 40 CFR part 60, subpart TTTT includes three subcategories for combustion turbines—natural gas-fired base load EGUs, natural gas-fired non-base load EGUs, and multi-fuel-fired EGUs. Base load EGUs are those that sell electricity in excess of the site-specific electric sales threshold to an electric distribution network on both a 12-operating-month and 3-year rolling average basis. Non-base load EGUs are those that sell electricity at or less than the site-specific electric sales threshold to an electric distribution network on both a 12-operating-month and 3-year rolling average basis. Multi-fuel-fired EGUs combust 10 percent or more (by heat input) of fuels not meeting the definition of natural gas on a 12-operating-month rolling average basis.

a. Legal Basis for Subcategorization

As noted in section V.C.1, 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 F3d at 933. As also noted in section V.C.1, in prior CAA section 111 rules, the EPA has subcategorized on numerous bases, including, among other things, fuel type and load.

b. Electric Sales Subcategorization (Low, Intermediate, and Base Load Combustion Turbines)

As noted earlier, in the 2015 NSPS, the EPA established separate standards for 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 combustion 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 but 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 is proposing changes to the subcategories in 40 CFR part 60, subpart TTTTa that will be applicable to sources that commence construction or reconstruction after the date of this proposed rulemaking. First, the Agency is proposing 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. It is important to note that this would have the effect of lowering the electric sales threshold. In addition, the EPA is proposing to further divide 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 one 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.[470] The EPA default is to reference all technologies on a HHV basis,[471] and the Agency is proposing to base 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.[472]

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*

[470] 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, *etc.*)) within the pipeline and will slightly move the ratio.

[471] Natural gas is also sold on a HHV basis.

[472] 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.

output, which reflects the EGU gross output minus its parasitic load.[473]

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 proposing output-based standards based on gross output. However, to recognize the superior environmental benefit of minimizing auxiliary/parasitic loads, the Agency is proposing to include optional equivalent standards on a net output basis. To convert from gross to net-output based standards, the EPA used a 1 percent auxiliary load for simple cycle turbines, a 2 percent auxiliary load for combined cycle turbines, and a 7 percent auxiliary load for combined cycle EGUs using 90 percent CCS.

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.

For the reasons noted below, the EPA is proposing in 40 CFR part 60, subpart TTTTa that the design efficiency be based on the HHV efficiency instead of LHV efficiency and that the 50 percent maximum and 33 percent minimum restriction not be included. 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.[474] The 33 percent criterion is 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 is not proposing that they be used to determine the electric sales threshold. By basing the electric sales threshold on the HHV design efficiency, the 50 percent restriction is no longer appropriate because currently available combined cycle designs operating as intermediate load combustion turbines would be limited to selling 55 percent of their potential electric output. 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 is also proposing 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 of less than 33 percent; and this will likely have no cost or emissions impact. However, this provides assurance that new combustion turbines will maximize design efficiencies. Because of this relationship between the electric sales threshold and the design efficiency of an individual EGU, the proposed definition of design efficiency would have the effect of lowering the electric sales threshold between the base load and non-base load subcategories. For combined cycle EGUs, the current base load electric sales threshold is 55 percent. Proposing the definition of the design efficiency to be based on HHV would make the base load electric sales threshold for combined cycle EGUs between 46 and 55 percent.[475] The current electric sales threshold for simple cycle turbines (*i.e.,* non-base load) peaks in a range of 40 to 49 percent of potential electric sales. Under the proposed definition, simple cycle turbines would be able to sell no more than between 33 and 40 percent of their potential electric output without moving into the base load subcategory. A design efficiency definition based on the HHV will have the effect of decreasing the electric sales threshold in relative terms by 19 percent and absolute terms by 7 to 9 percent.[476] The EPA is soliciting comment on whether the intermediate/base load electric sales threshold should be reduced further. The EPA is considering a range that would lower the base load electric sales threshold for simple cycle combustion turbines to between 29 to 35 percent (depending on the design efficiency) and to between 40 to 49 percent for combined cycle combustion turbines (depending on the design efficiency). This would be equivalent to reducing the design efficiency by 6 percent (*e.g.,* multiplying by 0.94) when determining the electric sales threshold.

The EPA determined that proposing to lower the electric sales threshold is appropriate for new combustion turbines because, as will be discussed later, the first component of BSER for both intermediate load and base load turbines is based on highly efficient generation. Combined cycle units are significantly more efficient than simple cycle turbines; and therefore, in general,

[473] 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 loses'' 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.

[474] 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.

[475] The electric sales threshold for combined cycle EGUs with the highest design efficiencies would remain at 55 percent.

[476] The design efficiency appears twice in the equation used to determine the electric sales threshold. Amending the design efficiency to use the HHV numeric value results in a larger reduction in the electric sales threshold than the difference between the HHV and LHV design efficiency.

the EPA should be focusing its determination of the BSER for base load units on that more efficient technology. In the 2015 NSPS, the EPA used a higher sales threshold because of the argument that less efficient simple cycle turbine technology served a unique role that could not be served by more efficient combined cycle technology. At the time, the EPA determined that a BSER based exclusively on that more efficient technology could exclude the building of simple cycle turbines that are needed to maintain electric reliability. With improvements to the ramp rates for combined cycle units and with integrated renewable/energy storage projects becoming more common, these less efficient simple cycle turbines are no longer the only technology that can serve this purpose. Further, as EGUs operate more, they have more hours of steady state operation relative to hours of startup/cycling. Amending the electric sales threshold would result in GHG reductions by assuring that the most efficient generating and lowest emitting combustion turbine technology is used for each subcategory. Therefore, the proposed change to calculate the design efficiency on a HHV basis will result in additional emission reductions at reasonable costs.

Based on EIA 2022 model plants, combined cycle EGUs have a lower levelized cost of electricity (LCOE) at capacity factors above approximately 40 percent compared to simple cycle EGUs operating at the same capacity factors. This supports the proposed base load electric 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 their unit as a base load unit. Furthermore, based on an analysis of monthly emission rates, recently constructed combined cycle EGUs maintain a 12-operating-month emissions rates at 12-operating-month capacity factors of less than 55 percent (the base load electric sales threshold in subpart TTTT) relative to operation at higher capacity factors. Therefore, the base load subcategory operating range could be expanded in subpart TTTTa without impacting the stringency of the numeric standard. However, at 12-operating-month capacity factors of less than approximately 50 percent, emission rates of combined cycle EGUs increase relative to operation at a higher capacity factor. It takes longer for a HRSG to begin producing steam that can be used to generate additional electricity than the time it takes a combustion engine to reach full power. Under operating conditions with a significant number of starts and stops, typical of 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 efficient simple cycle combustion 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. Above capacity factors of approximately 40 percent, the average run time per start for combined cycle EGUs tends to increase significantly and the HRSG would be available to contribute additional electric generation. For more information on the impact of capacity factors on the emission rates of combined cycle EGUs see the *Efficient Generation at Combustion Turbine Electric Generating Units* TSD, which is available in the rulemaking docket.

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 on 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, the vast majority of simple cycle turbines that commenced operation between 2010 and 2016 (the most recent simple cycle combustion turbines not subject to 40 CFR part 60, subpart TTTT) have operated well below the base load electric sales threshold in 40 CRF 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 proposing 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 proposed threshold is not overly restrictive since a simple cycle turbine could operate on average for more than 8 hours a day.

iii. Low and Intermediate Load Subcategories

The EPA is proposing in 40 CFR part 60, subpart TTTTa to create a low load subcategory to include combustion turbines that operate only during periods of peak electric demand (*i.e.,* peaking units) which would be separate from the intermediate load subcategory. Low load combustion turbines also provide ramping capability and other ancillary serves 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, we use the terms ''electric sales'' and ''capacity factor'' interchangeably.) Peaking units only operate for short periods of time and potentially at relatively low duty cycles.[477] 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 peaking units.

To determine the electric sales threshold—that is, to distinguish

[477] 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.

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 found the 10 percent level problematic for two reasons. First, simple cycle combustion turbines operating at that level or lower have highly variable emission rates, and therefore it would be 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 which is only achievable for simple cycle combustion 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.

Importantly, based on the EPA's review of hourly emissions data, above a 15 percent capacity factor, GHG emission rates for many simple cycle combustion turbines begin to stabilize, see the *Simple Cycle Stationary Combustion Turbine EGUs* TSD, which is available in the rulemaking docket. 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. Approximately 60 percent of recently constructed simple cycle turbines have maintained 12-operating-month capacity factors of 15 percent or less while two-thirds of recently constructed simple cycle turbines have operated at capacity factors of 20 percent or less; and, the emission rates clearly stabilize for the majority of simple cycle turbines operating at capacity factors of greater than 20 percent. Nearly 80 percent of recently constructed simple cycle turbines maintain maximum 12-operating-month capacity factors of 25 percent or less. Based on this information, the EPA is proposing the low load electric sales threshold—again, the dividing line to distinguish between the intermediate- and low-load subcategories—to be 20 percent and is soliciting comment on a range of 15 to 25 percent. The EPA is also soliciting comment on whether the low load electric sales threshold should be determined by a site-specific threshold based on three quarters of the design efficiency of the combustion turbine.[478] Under this approach, simple cycle combustion turbines selling less than 18 to 22 percent of their potential electric output (depending on the design efficiency) would still be considered low load combustion turbines. This ''sliding scale'' electric sales threshold approach is similar to 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 be able to sell between 26 to 31 percent of their potential electric output while still being considered low load combustion turbines.

Placing low load and intermediate load combustion turbines into separate subcategories is consistent with how these units are operated and how emissions from these units can be quantified and controlled. Consistent with the 2015 NSPS, the BSER analysis for base load combustion turbine EGUs assumes the use of combined cycle technology and the BSER analysis for intermediate and low load combustion turbine EGUs assumes the use of simple cycle technology. However, the Agency notes that combined cycle EGUs can elect to operate at lower levels of electric sales and be classified as intermediate or peaking EGUs. In this case, owners/operators of combined cycle EGUs would be required to comply with the standards of performance for intermediate or peaking EGUs.

c. Multi-Fuel-Fired Combustion Turbines

40 CFR part 60, subpart TTTT subcategorizes multi-fuel-fired combustion turbines 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.[479] 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, m^3) (950 and 1,100 British thermal units (Btu) per dry standard cubic foot). Natural gas typically contains 95 percent methane and has a heating value of 1,050 Btu/lb.[480] 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 concerns, the EPA is proposing to eliminate the multi-fuel subcategory for low, intermediate, and base load combustion turbines in 40 CFR part 60, subpart TTTTa. This would mean that new multi-fuel-fired turbines that commence construction or reconstruction after the date of this proposal will fall within a particular subcategory depending on their level of electric sales. The EPA also proposes 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 Rule, the maximum allowable heat input-based emissions rate would be 160 lb CO_2/MMBtu. For example, a standard of performance based on efficient generation would be 33 percent

[478] 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 quarters of the design efficiency reduces the electric sales threshold by half.

[479] 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).

[480] Note that 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/Sm3, and 10 percent of the heat input could be coming from a fuel not meeting the definition of natural gas.

higher for a fuel oil-fired combustion turbine compared to a natural gas-fired combustion turbine. This would assure that the BSER, in this case efficient generation, is applied, while at the same time accounting for the use of multiple fuels. As explained in section VII.F, in the second phase of the NSPS, the EPA is proposing to further subcategorize base load combustion turbines based on whether the combustion turbine is combusting hydrogen. During the first phase of the NSPS, all base load combustion turbines would be in a single subcategory. Table 2 summarizes the proposed electric sales subcategories for combustion turbines.

TABLE 2—PROPOSED SALES THRESHOLDS FOR SUBCATEGORIES OF COMBUSTION TURBINE EGUS

Subcategory	Electric sales threshold (percent of potential electric sales)
Low Load	≤20 percent.
Intermediate Load	>20 percent and ≤site-specific value determined based on the design efficiency of the affected facility. • Between ~ 33 to 40 percent for simple cycle combustion turbines. • Between ~ 45 to 55 percent for combined cycle combustion turbines.
Base Load	>Site-specific value determined based on the design efficiency of the affected facility. • Between ~ 33 to 40 percent for simple cycle combustion turbines. • Between ~ 45 to 55 percent for combined cycle combustion turbines.

G. Proposed 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 proposes that because the technology for reducing GHG emissions from combustion turbines is advancing rapidly, a multi-phase set of standards of performance, which reflect a multi-component BSER, is appropriate for base load and intermediate 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 for both base load and intermediate load combustion turbines. 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 2032 and 2035 respectively, the BSER for base load turbines includes either 30 percent low-GHG hydrogen co-firing or 90 percent capture CCS, and beginning in 2032 the BSER for intermediate load EGUs includes 30 percent low-GHG hydrogen co-firing. The affected EGUs would be subject to either an emissions rate that reflects continued use of highly efficient generation coupled with CCS, or one that reflects continued use of highly efficient generation coupled with co-firing low-GHG hydrogen. For the third phase of the standards, beginning in 2038 for base load turbines that began co-firing 30 percent low-GHG hydrogen in 2032, the BSER includes co-firing 96 percent low-GHG hydrogen. In addition, the EPA is proposing a single component BSER, applicable from the date of proposal, for low 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.

For new and reconstructed natural gas-fired base load combustion turbine EGUs, the EPA proposes to find that the most efficient available combined cycle technology—which qualifies as the BSER for base load combustion turbines—supports a standard of 770 lb CO_2/MWh-gross for large natural gas-fired EGUs (*i.e.,* those with a nameplate heat input greater than 2,000 MMBtu/h) and 900 lb CO_2/MWh-gross for natural gas-fired small EGUs (*i.e.,* those with a nameplate base load rating of 250 MMBtu/h). The proposed standard of performance for natural gas-fired base load EGUs with base load ratings between 250 MMBtu/h and 2,000 MMBtu/h would be between 900 and 770 lb CO_2/MWh-gross and be determined based on the base load rating of the combustion turbine.[481] The EPA proposes to find 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 proposes 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 proposes these standards to apply at all times and compliance to be determined on a 12-operating-month rolling average basis.

The EPA has determined 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 is proposing 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 site-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-operaitng month period would be 1,070 lb CO_2/MWh-gross.[482]

[481] 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 NGCC EGU 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.

[482] 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

To determine what emission rates are currently achieved by existing high-efficiency combined cycle EGUs and simple cycle EGUs, the EPA reviewed 12-operating-month generation and CO_2 emissions data from 2015 through 2021 for all combined and simple cycle EGUs 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 and simple cycle EGU fleets. Since an NSPS is a never-to-exceed standard, the EPA is proposing 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 calculated 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.

For base load combustion turbines, the EPA evaluated three emission rates: 730, 770, and 800 lb CO_2/MWh-gross. An emissions rate of 730 lb CO_2/MWh-gross has been demonstrated by a single combined cycle facility—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 is not proposing 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 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 [483]) and combined cycle EGUs with the best performance when operated as intermediate load EGUs.[484] Either of these outcomes could result in greater overall emissions from the power sector. An advantage of multi-shaft (2-on-1 and 3-on-1) 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 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.[485]

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 in areas where water requirements could have significant ecological impacts. Therefore, the EPA proposes that the efficient generation standard for base load EGUs should account for the use of dry cooling.

Finally, the Okeechobee Clean Energy Center is a relatively new EGU and full efficiency degradation might not be accounted for in the emissions analysis. Therefore, the EPA is not proposing that an emissions rate of 730 lb CO_2/MWh-gross is an appropriate nationwide standard. However, the EPA is soliciting comment on whether the use of alternate working fluid, such as supercritical CO_2, or other potential efficiency improvements would make this emissions rate an appropriate standard of performance for base load combustion turbines.

An emissions rate of 770 lb CO_2/MWh-gross has been demonstrated by 14 percent of recently constructed combined cycle EGUs. These turbines include combined cycle EGUs using 1-on-1 configurations and dry cooling, are manufactured by multiple companies, and have long-term emissions data that fully account for potential degradation in efficiency. One of the best performing large combined cycle EGUs that has maintained an emissions rate of 770 lb CO_2/MWh-gross is the Dresden plant, located in Ohio.[486] This 2-on-1 combined cycle facility, uses a recirculating cooling tower, and has maintained an emissions rate of 765 lb CO_2/MWh-gross, measured over 12 operating months with 99 percent confidence. The turbine engines are rated at 2,250 MMBtu/h, which demonstrates that the standard of 770 lb CO_2/MWh-gross is achievable at a heat input rating of 2,000 MMBtu/h. In addition, while a 2-on-1 configuration and a cooling tower are more efficient than a 1-on-1 configuration and dry cooling, the Dresden Energy Facility does not use the most efficient combined cycle design currently available. Multiple more efficient designs have been developed since the

CO_2/MWh) to get the applicable emissions rate (1,070 lb CO_2/MWh).

[483] 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.

[484] 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.

[485] 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.

[486] 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.

Dresden Energy Facility commenced operation a decade ago that more than offset these efficiency losses. Therefore, the EPA proposes that while the Dresden combined cycle EGUs uses a 2-on-1 configuration with a cooling tower, it demonstrates that an emissions rate of 770 lb CO_2/MWh-gross is achievable for all new large combined cycle EGUs. For additional information on the EPA analysis of emission rates for high efficiency base load combined cycle EGUs, see the *Efficient Generation at Combustion Turbine Electric Generating Units* TSD, which is available in the rulemaking docket.

The EPA is not proposing an emissions rate of 800 lb CO_2/MWh-gross because it does not represent the most efficient combined cycle EGUs designs. Nearly half of recently constructed combined cycle EGUs have maintained an emissions rate of 800 lb CO_2/MWh-gross. However, the EPA is soliciting comment on whether this higher emissions rate is appropriate on grounds that it would increase flexibility and reduce costs to the regulated community by allowing more available designs to operate as base load combustion turbines.

With respect to small combined cycle combustion turbines, the best performing unit 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.[487] 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. 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 250 MMBtu/h should be able to maintain an emissions rate of 900 lb CO_2/MWh-gross.[488] In addition, there is a commercially available HRSG that uses supercritical CO_2 instead of steam as the working fluid. This HRSG would be significantly more efficient than the HRSG that uses dual pressure steam, which is common for small combined cycle EGUs.[489] When these efficiency improvements are accounted for, a new small natural gas-fired combined cycle EGU would be able to maintain an emissions rate of 850 lb CO_2/MWh-gross. Therefore, the Agency is soliciting comment on whether the small natural gas-fired base load combustion turbine standard of performance should be 850 lb CO_2/MWh-gross.

In summary, the Agency solicits comment on the following range of potential standards of performance:

- New and reconstructed natural gas-fired base load combustion turbines with a heat input rating that is greater than 2,000 MMBtu/h: a range of 730–800 lb CO_2/MWh-gross;
- New and reconstructed natural gas-fired base load combustion turbines with a heat input rating of 250 MMBtu/h: a range of 850 to 900 lb CO_2/MWh-gross.

For intermediate load combustion turbines, the EPA evaluated the performance of recently constructed high efficiency natural gas-fired simple cycle EGUs. The EPA evaluated three emission rates for the intermediate load standard of performance: 1,200, 1,150, and 1,100 lb CO_2/MWh-gross. Sixty two percent of recently constructed intermediate load simple cycle EGUs have maintained an emissions rate of 1,200 lb CO_2/MWh-gross, 17 percent have maintained an emissions rate of 1,150 lb CO_2/MWh-gross, and 6 percent have maintained an emissions rate of 1,100 lb CO_2/MWh-gross. However, the units that have maintained an emissions rate of 1,100 lb CO_2/MWh-gross generally have a single large aeroderivative combustion turbine design. In contrast, the ones that have maintained an emission rate of 1,150 lb CO_2/MWh-gross have multiple different designs, including an industrial frame combustion turbine design, and are made by multiple manufacturers. Therefore, the EPA is proposing an intermediate load standard of performance of 1,150 lb CO_2/MWh-gross. The Agency is soliciting comment on whether the standard should be 1,100 lb CO_2/MWh-gross, or whether that would result in unacceptably high costs because currently only a single design for a large aeroderivative simple cycle turbine would be able to meet this standard. The Agency is also soliciting comment on a standard of performance of 1,200 lb CO_2/MWh-gross. While this would achieve fewer GHG reductions, it would increase flexibility, and potentially reduce costs, to the regulated community by allowing the currently available designs to operate as intermediate load combustion turbines. For additional information on the EPA analysis of emission rates for high efficiency intermediate load simple cycle EGUs, see the *Efficient Generation at Combustion Turbine Electric Generating Units* TSD, which is available in the rulemaking docket

The EPA is also soliciting comment on whether the use of steam injection is applicable to intermediate load combustion turbines. Steam injection is the use of a relatively low cost HRSG to produce steam that is injected into the combustion chamber of the combustion turbine engine instead of using a separate steam turbine.[490] Advantages of steam injection include improved efficiency and increases the output of the combustion turbine as well as reducing NO_X emissions. Combustion turbines using steam 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. Combustion turbines using steam injection are simpler and have lower capital costs than combined EGUs but have lower efficiencies. The EPA is aware of a single combustion turbine that is using steam injection that has maintained a 12-operaitng month emission rates of less than 1,000 lb CO_2/MWh-gross. The EPA requests that commenters include information on whether this technology would be applicable to intermediate load combustion turbines and could be part of either the first or second component of the BSER along with cost information.[491]

2. Phase-2 Standards

The use of CCS and hydrogen co-firing are both approaches developers are considering to reduce GHG emissions beyond highly efficient generation. However, as noted above, these approaches apply to different subcategories and are not applicable to

[487] 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 does not materially reduce 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.

[488] To estimate an achievable emissions rate for an efficient combined cycle EGU at 250 MMBtu/h the EPA assumed a linear relationship for combined cycle efficiency with turbine engines with base load ratings of less than 2,000 MMBtu/h.

[489] 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).

[490] 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.

[491] The second component of the BSER, 30 percent low-GHG hydrogen co-firing, would reduce the emissions rate to 880 lb CO_2/MWh-gross.

the same EGUs. The proposed phase-2 standards are in table 3.

TABLE 3—PHASE-2 STANDARDS OF PERFORMANCE

Subcategory	BSER	Standard of performance
Low load	Lower emitting fuels	120–160 lb CO_2/MMBtu.
Intermediate load	Highly efficient simple cycle technology coupled with co-firing 30 percent (by volume) low-GHG hydrogen.	1,000 lb CO_2/MWh-gross.
Base load adopting the CCS pathway	Highly efficient combined cycle technology coupled with 90 percent CCS.	90 lb CO_2/MWh-gross.
Base load adopting the low-GHG hydrogen co-firing pathway.	Highly efficient combined cycle technology coupled with co-firing 30 percent (by volume) low-GHG hydrogen.	680 lb CO_2/MWh-gross.

Co-firing 30 percent by volume low-GHG hydrogen reduces emissions by 12 percent. The EPA applied this percent reduction to the emission rates for the intermediate load and base load units adopting the low-GHG hydrogen co-firing pathway subcategories, to determine the phase-1 standards. For the base load combustion turbines adopting the CCS subcategory, the EPA reduced the emissions rate by 89 percent to determine the CCS based phase-2 standards.[492] 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. However, if the 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. As noted in section VII.F.3.b.iii(A)(2) of this preamble, the operating availability (*i.e.,* the amount of time a process operates relative to the amount of time it planned to operate) of industrial processes is usually less than 100 percent. Assuming that CO_2 capture achieves 90 percent capture when available to operate, that CCS is available to operate 90 percent of the time the combustion turbine is operating, and that the combustion turbine operates the same whether or not CCS is available to operate, total emission reductions would be 81 percent. Higher levels of emission reduction could occur for higher capture rates coupled with higher levels of operating availability relative to operation of the combustion turbine. If the combustion turbine were not permitted to operate when CCS was unavailable, there may be local reliability consequences or issues during startup or shutdown, and the EPA is soliciting comment on how to balance these issues. Additionally, the EPA is soliciting comment on the range of reduction in emission rate of 75 to 90 percent.

The standards of performance for the intermediate and base load combustion turbines would also 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 1,300 lb CO_2/MWh-gross, 120 lb CO_2/MWh-gross, and 910 lb CO_2/MWh-gross for the intermediate load, non low-GHG hydrogen co-firing base load, and low-GHG hydrogen co-firing base load subcategories respectively.

3. Phase-3 Standards

The third component of the BSER is applicable to owner/operators of base load combustion turbines that elect to implement early GHG reductions (*i.e.,* comply with an emissions rate of 680 lb CO_2/MWh-gross starting in January 2032). The phase 3 BSER standard of performance increases the GHG reduction requirements and is based on co-firing 96 percent by volume low-GHG hydrogen in addition to the use of highly efficient combined cycle technology in combination with the best operating and maintenance practices. The proposed phase-3 standards are in table 4.

TABLE 4—PHASE-3 STANDARDS OF PERFORMANCE

Subcategory	BSER	Standard of performance
Base load electing to implement early GHG reductions.	Highly efficient combined cycle technology coupled with co-firing 89 percent (by heat input) low-GHG hydrogen.	90 lb CO_2/MWh-gross.

Co-firing 89 percent by heat input (96 percent by volume) low-GHG hydrogen reduces GHG emissions by 89 percent. The EPA applied this percent reduction to the emission rates for base load under phase 1 of the BSER. Similar to the phase 1 and 2 standards of performance, the numeric standard would 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.

As a variation on proposing the date for meeting this standard as 2038, the EPA solicits comment on proposing the date as 2035, coupled with authorizing an approach for crediting early reductions, under which a source that achieves reductions due to co-firing low-GHG hydrogen starting in 2032 may apply credit for those reductions to its emission rate beginning in 2035. Another, more stringent, variation of this approach would be to allow credit only for reductions below the emission rate otherwise required by 2032. Other

[492] 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.

variations would allow sources to generate credits from reductions from co-firing low-GHG hydrogen, or from any other reductions below their standard of performance, in any year before 2035. In this manner, the source would be authorized to comply with its 2035 standard in part through use of credits generated by making reductions beginning in 2032. Under such an approach, early credits could only be used by the unit that generated those credits. For instance, a unit co-firing 30 percent low-GHG hydrogen prior to 2035 would be able to generate credits that it could use in 2035 and beyond. This would allow a unit co-firing low-GHG hydrogen to ramp up the amount it co-fired over time, while still achieving the same amount of emission reductions that would have been achieved had the unit co-fired enough low-GHG hydrogen (*e.g.,* 96 percent by volume) starting in 2035. Another variation on this approach would be to treat such a crediting scheme as a compliance alternative to the CCS BSER by showing equivalent emission reductions, rather than the standard itself.

The EPA proposes the following mechanism to ensure that affected sources in the base load subcategory comply with the applicable standard of performance in the event that the EPA finalizes both the CCS pathway (that is, the use of 90-percent-capture CCS by 2035) and the low-GHG hydrogen pathway (that is, co-firing 30 percent low-GHG hydrogen by 2032 and 96 percent by 2038). The EPA proposes that affected sources must notify the EPA by January 1, 2031, which pathway they are selecting, and thus which standard they intend to comply with. If they select the low-GHG hydrogen pathway, they must comply with the applicable standard based on co-firing 30 percent hydrogen (by volume) in 2032 through 2037. In addition, in 2033 through 2037, they must be prepared to demonstrate that they complied with the applicable standard based on co-firing 30 percent low-GHG hydrogen in the preceding years, beginning in 2032. In 2038, they must comply with the applicable standard based on co-firing 96 percent (by volume) now-GHG hydrogen.

H. Reconstructed Stationary Combustion Turbines

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 is proposing to use the same emissions analysis for both new and reconstructed stationary combustion turbines. For each of the subcategories, the EPA is proposing that the proposed BSER results in the same standard of performance for new stationary combustion turbines and reconstructed stationary combustion turbines. Since reconstructed turbines could likely incorporate technologies to co-fire hydrogen as part of the reconstruction process at little or no cost, the low-GHG hydrogen co-firing would likely to be similar to those for newly constructed combustion turbines. For CCS, the EPA approximated the cost to add CCS to a reconstructed combustion turbine by increasing the capital costs of the carbon capture equipment by 10 percent relative to the costs for a newly constructed combustion turbine. This increases the capital cost from $949/kW to $1,044/kW.[493] Using a 12-year amortization period, a 90 percent-capture amine-based post combustion CCS system increases the LCOE by $8.5/MWh and has overall CO_2 abatement costs of $25/ton ($28/metric ton).

A reconstructed stationary combustion turbine is not required to meet the standards if doing so is deemed to be ''technologically and economically'' infeasible.[494] 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 would consider 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 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. EPA is not proposing, or soliciting comment on whether it should propose, standards of performance for modifications of combustion turbines.

J. Startup, Shutdown, and Malfunction

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the U.S. Court of Appeals for the District of Columbia Circuit (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. Consistent with *Sierra Club* v. *EPA,* the EPA is proposing 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

[493] The kW value used as reference for the costs is the output from the combined cycle EGU prior to the installation of the CCS.

[494] 40 CFR 60.15(b)(2).

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 is proposing to retain in subpart TTTTa the requirements that sources comply with the standard(s) at all times. Therefore, the EPA is proposing in table 3 of the new subpart TTTTa to override the general provisions for SSM provisions. The EPA is proposing that all standards in subpart TTTTa apply at all times.

The EPA has attempted to ensure that the general provisions we are proposing to override are inappropriate, unnecessary, or redundant in the absence of the SSM exemption. The EPA is specifically seeking comment on whether we have successfully done so.

In proposing 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, has not proposed 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 proposing 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 case law 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 will include a discussion on the current testing and monitoring requirements of the NSPS and any additions the EPA is proposing to include in 40 CFR part 60, subpart TTTTa.

1. General Requirements

The current rule allows three approaches for determining compliance with its emissions limits: Continuous measurement using CO_2 CEMS and flow measurements for all EGUs; calculations using hourly heat input and 'F' factors[495] for EGUs firing uniform oil or gas or non-uniform fuels; or Tier 3 calculations using fuel use and carbon content as described in GHGRP regulations for EGUs firing non-uniform fuels. The first two approaches are in use for carbon dioxide 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 carbon dioxide, nitrous oxide, and methane reporting from stationary fuel combustion sources (40 CFR part 98, subpart C).

The EPA believes continuing the use of these familiar approaches already in use by other programs represents a cost-effective means of obtaining quality assured data requisite for determining carbon dioxide mass emissions. Therefore, no changes to the current ways of collecting carbon dioxide and associated data needed for mass determination, such as flow rates, fuel heat content, fuel carbon content, and the like, are proposed. Because no changes are proposed and because the cost and burden for EGU owners or operators are already accounted for by other rulemakings, this aspect of the proposed rule is designed to have minimal, if any, cost or burden associated with carbon dioxide testing and monitoring. In addition, the proposal contains no changes to measurement and testing requirements for determining electrical output, both gross and net, as well as thermal output, to current existing requirements.

However, the EPA requests comment on whether continuous carbon dioxide and flow measurements should become 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 or non-uniform fuel-fired calculation-based approaches for compliance. By way of reference, the annualized cost associated with adoption and use of continuous carbon dioxide and flow measurements where none now exist is estimated to be about $52,000. To the extent that the rule were to mandate continuous carbon dioxide and 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.

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 2022, to complement GHGRP subpart RR, the EPA proposed 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

[495] An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel.

reporting geologic sequestration in association with EOR.[496 497 498]

The current rule leverages the regulatory requirements under GHGRP subpart RR and does not reference GHGRP subpart VV. The EPA is proposing 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 proposed GHGRP subpart VV. If the emitting EGU sends the captured CO_2 offsite, it must assure that the CO_2 is managed at a facility subject to the GHGRP requirements, and the facility injecting the CO_2 underground must report under GHGRP subpart RR or proposed GHGRP subpart VV. This proposal 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, we are leveraging regulatory reporting 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 proposed GHGRP subpart VV. We also emphasize that this proposal 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 assure that captured CO_2 is managed at 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 proposed rule.

3. Requirements for Sources Co-Firing Low-GHG Hydrogen

Because the EPA is basing its proposed definition of low-GHG hydrogen consistent with IRC section 45V(b)(2)(D), it is reasonable, if possible and practicable, for the EPA to adopt, in whole or in part, the eligibility, monitoring, verification, and reporting protocols associated with IRC section 45V(b)(2)(D) when finalized by Treasury for the production of low-GHG hydrogen, and apply those protocols, as applicable, to requirements the EPA establishes for the demonstration by EGUs that they are using low-GHG hydrogen. Adopting very similar requirements for demonstrations by EGUs that they are using low-GHG hydrogen would help ensure there are not dueling eligibility requirements for low-GHG hydrogen production with overall emissions rates of 0.45 kg CO_2e/kg H_2 or less. Adopting similar methods for assessing GHG emissions associated with hydrogen production pathways would create clarity and certainty and reduce confusion.

The EPA is taking comment on its proposal to closely follow Treasury protocols in determining how EGUs demonstrate compliance with the fuel characteristics required in this rulemaking. The EPA is taking comment on what forms of acceptable mechanisms and documentary evidence should be required for EGUs to demonstrate compliance with the obligation to co-fire low-GHG hydrogen, including proof of production pathway, overall emissions calculations or modeling results and input, purchasing agreements, contracts, and energy attribute certificates. Given the complexities of tracking produced hydrogen and the public interest in such data, the EPA is also taking comment on whether EGUs should be required to make fully transparent their sources of low-GHG hydrogen and the corresponding quantities procured. The EPA is also seeking comment on requiring that EGUs using low-GHG hydrogen demonstrate that their hydrogen is exclusively from facilities that only produce low-GHG hydrogen, as a means of reducing demonstration burden and opportunities for double counting that could otherwise occur for hydrogen purchased from facilities that produce multiple types of hydrogen and the complex recordkeeping and documentation that would be necessary to reliably verify that the hydrogen purchased from such facilities qualifies. The EPA solicits comment on a mechanism to operationalize such a provision.

Treasury is currently developing implementing rules for IRC section 45V. Congress specified that tax credit eligibility for the credit tiers (45V(b)(2)(A), 45(V)(b)(2)(B), 45(b)(2)(C), and 45V(b)(2)(D)) should be based on an assessment of the estimated well-to-gate[499] GHG emissions of hydrogen production, determined based on the most recent Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (GREET model) or a successor model as determined by the Secretary of Treasury. Consistent with its proposal to define low-GHG hydrogen consistent with IRC section 45V(b)(2)(D), the EPA is also proposing that, for the purpose of demonstrating compliance with the requirement to combust low-GHG hydrogen under this NSPS, the maximum extent possible the same methodology specified in IRC section 45V and requirements currently under development should apply. One example would be requiring that the owner/operator of the combustion turbine obtain from the hydrogen producer from which they purchase low-GHG hydrogen the hydrogen producer's calculation of GHG levels associated with its hydrogen production using the GREET well-to-gate analysis. The GREET model is well established, designed to adapt to evolving knowledge, and capable of including technological advances. The EPA solicits comment on whether the Agency should consider unrelated or third-party verification as part of the standards required for EGUs to demonstrate compliance. Given the

[496] 87 FR 36920 (June 21, 2022).

[497] 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'').

[498] As described in 87 FR 36920 (June 21, 2022), both subpart RR and proposed 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.

[499] Well-to-gate analysis of lifecycle GHG emissions represents a smaller scope than cradle-to-grave analysis. Well-to-gate emissions of hydrogen production include those associated with fossil fuel or electricity feedstock production and delivery to the hydrogen facility; the hydrogen production process itself; and any associated CCS applied at the hydrogen production facility. Well-to-gate analysis does not consider emissions associated with the manufacture or end-of-life of the hydrogen production facility or facilities providing feedstock inputs to the hydrogen production facility. Nor does it consider emissions associated with transportation, distribution, and use of hydrogen beyond the production facility.

sequential timing of EPA and Treasury processes, the EPA may take further action, after promulgation of this NSPS, to provide additional guidance on application of Treasury's framework for IRC section 45V to this particular context. The EPA requests comment on its proposal to adopt as much as possible the methodology specified in IRC section 45V and any associated implementing requirements established by Treasury, once the methodology and implementing requirements are finalized, as part of the obligations for EGUs to demonstrate compliance with the requirement to combust low-GHG hydrogen under this NSPS.

Although proposing to incorporate as much as possible Treasury's eligibility, monitoring, reporting, and verification protocols, the EPA recognizes that Treasury protocols concern hydrogen production, whereas the EPA's proposed requirements apply to affected EGUs that use the hydrogen to demonstrate compliance with the low-GHG hydrogen co-firing obligations. The EPA is also taking comment on several underlying policy issues relevant to ensuring that hydrogen used to comply with this rule is low-GHG hydrogen. One reason that the EPA is considering whether an alternative method to the Treasury guidance may be needed to determine whether hydrogen meets the requirements to be considered low-GHG is because hydrogen production facilities that begin construction after 2032 will not be eligible for the tax credits. The EPA wants to make sure a pathway exists for low-GHG hydrogen to be used for compliance purposes even if the producer began construction after 2032 and is not receiving tax credits.

Given this and other uncertainties, the EPA is taking comment on issues that would be relevant should the Agency develop its own protocols for EGUs to demonstrate compliance with the overall emissions rate in IRC section 45V(b)(2)(D) for co-firing as BSER in this rulemaking.

The EPA is also taking comment on strategies the EPA could adopt to inform its own eligibility, monitoring, reporting and verification protocols for ensuring compliance with the 0.45 kg CO_2e/kg H_2 or less emission rate for compliance with the low-GHG provisions of this rule, if the EPA does not adopt Treasury's protocols. The purpose of these strategies would be to ensure that EGUs are using only low-GHG hydrogen, *i.e.,* hydrogen that results in GHG emissions of less than 0.45 kg CO_2 per kg H_2. The EPA is taking comment on the appropriateness of requiring EGUs to provide verification that the hydrogen they use complies with this standard, as demonstrated by the GREET model for estimating the GHG emissions associated with hydrogen production from well-to-gate, and to what extent EGUs should be required to verify the accuracy of the energy inputs and conclusions of the GREET model for the hydrogen used by the EGU to comply with this rule.

Several important considerations with respect to determining overall GHG emissions rates for hydrogen production pathways have been raised by researchers and have been picked up in trade press coverage.[500] [501] Given the importance of these issues, the recent accumulation of relevant research, and the range of stakeholder positions, the EPA is taking comment on the need for (and design of) approaches and appropriate timeframes for allowing EGUs to meet requirements for geographic and temporal alignment requirements to verify that the hydrogen used by the EGU is compliant with this rulemaking, recognizing that EPA's low-GHG standard for compliance would not begin until 2032. The EPA is soliciting comment on these issues, as they relate to co-firing low-GHG hydrogen in combustion turbines and the requisite need to only utilize the lowest-GHG hydrogen in these applications as specified in IRC section 45V, specifically IRC section 45V(b)(2)(D). The EPA notes this is one of multiple forthcoming opportunities for public comment on this suite of issues, and the EPA's proposal is specific to low-GHG hydrogen in the context of qualifying a co-firing fuel as part of BSER.

It is important to note that the landscape for methane emissions monitoring and mitigation is changing rapidly. For example, the EPA is in the process of developing enhanced data reporting requirements for petroleum and natural gas systems under its GHGRP, and is in the process of finalizing requirements under New Source Performance Standards and Emission Guidelines for the oil and gas sector that will result in mitigation of methane emissions. With these changes, it is expected that the quality of data to verify methane emissions will improve and methane emissions rates will change over time. Adequately identifying and accounting for overall emissions associated with methane-based feedstocks is essential in the determination of accurate overall emissions rates to comply with the low-GHG hydrogen standards in this rule. The EPA is taking comment on how methane leak rates can be appropriately quantified and conservatively estimated given the inherent uncertainties and wide range of basin-specific characteristics. The EPA is soliciting comment on whether EGUs should be required to produce a demonstration of augmented in-situ monitoring requirements to determine upstream emissions when methane feedstock is used for low-GHG hydrogen used by the EGU for compliance with this rule. The EPA is also taking comment on whether EGUs should use a default assumption for upstream methane leak rates in the event monitoring protocols are not finalized as part of this rulemaking, and what an appropriate default leak rate should be, including what evidence would be necessary for the EGU to deviate from that default assumption. The EPA is also taking comment on the appropriateness of requiring EGUs to provide CEMS data for SMR or ATR processes seeking to produce qualifying low-GHG hydrogen for co-firing to ensure the amount of carbon captured by CCS is properly and consistently monitored and outage rates and times are recorded and considered. The EPA is soliciting comment on providing EGUs with a representative and climate-protective default assumption for carbon capture rates associated with SMR and ATR hydrogen pathways, inclusive of outages, if CCS is used for low-GHG hydrogen production as part of this rulemaking, including what evidence would be necessary for the EGU to deviate from that default assumption. These topics are particularly important to ensuring use of low-GHG hydrogen given the DOE estimate that by 2050, reformation-based production with CCS may account for 50–80 percent of total U.S. hydrogen production.[502] The EPA is taking comment on requiring substantiation of energy inputs used in any overall GHG emissions assessment for hydrogen production used by EGUs for compliance with this requirement.

In comparison with petrochemical-based hydrogen production pathways discussed above, electrolyzer-based hydrogen production has the potential for lower-GHG hydrogen because the technology is based on splitting water (H_2O) molecules rather than splitting hydrocarbons (*e.g.,* CH_4).[503] For EGUs

[500] Without Sufficient Guardrails, the Hydrogen Tax Credit Could Increase Emissions—Union of Concerned Scientists. *ucsusa.org.*

[501] Hydrogen's Power Grid Demands Under Scrutiny in Tax Credit. *bloomberglaw.com.*

[502] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.*

[503] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/*

Continued

relying on hydrogen produced using this pathway, the EPA is seeking comment on the method for assuring that energy inputs to that production are consistent with the low-GHG hydrogen standard that EGUs would be required to meet under this rule. Specifically, the EPA is taking comment on requiring EGUs to provide substantiation of low-GHG energy inputs into any overall emissions assessment for electrolytic hydrogen production pathways for hydrogen used by the EGUs to comply with the low-GHG hydrogen standard in this rule. Energy Attribute Certificates (EACs) (EACs from renewable sources are sometimes known as Renewable Energy Credits or RECs) are produced for each megawatt hour of low-GHG generation and therefore offer a measurable, auditable, and verifiable approach for determining the GHG emissions associated with the energy used to make the low-GHG hydrogen. EACs with specific attributes are commonly used in the electricity markets to substantiate corporate clean energy commitments and use, as well as for utility compliance with State RPS and CES programs. The EPA is taking comment on requiring EGUs to provide EAC verification for low-GHG emission energy inputs into GHG emissions assessments for hydrogen used by that EGU to comply with the low-GHG standard in this rule, for all hydrogen pathways. The EPA is seeking comment on allowing EGUs to use EACs as part of the documentation required for verifying the use of low-GHG hydrogen.

The EPA is taking comment on allowing EGUs to comply with the low-GHG hydrogen standard in this rule if they demonstrate that the hydrogen used is produced from: (1) dedicated low-GHG emitting electricity from a generator sited on the utility side of a meter that is contractually obligated to a electrolyzer, (2) a generator collocated with an electrolyzer and sited behind a common utility meter, or (3) a generator whereby the electrolyzer and generator are collocated but not interconnected to the grid and have no grid exchanges of power. The EPA is also taking comment on approaches for EGUs to demonstrate that purchased hydrogen produced from an electrolyzer could meet the low-GHG standard, in whole or part, through an allotment of zero emitting electricity to a portion of the electrolyzer's hydrogen output. Many announced hydrogen production projects pair electrolyzers with renewable (including hydroelectric) or nuclear energy, which are likely capable of producing low-GHG hydrogen. Wind and solar renewable generation sources are variable, and nuclear units go offline for refueling purposes. In these cases, and others, grid-based electricity, which often has a high carbon intensity might be pursued in combination with EACs for each megawatt hour of grid-based energy used. Aligning the time and place (temporal and geographic alignment) of EACs used to allocate and describe delivered grid-based electricity consumed could potentially help ensure that hydrogen used is low-GHG hydrogen.[504] Some degree of alignment geographically, for example delivery of power to the balancing authority in which the electricity is consumed by the electrolyzer, could ensure that EACs used are representative of the allocation of the energy mix consumed by the electrolyzers. However, alignment could also entail trade-offs, about which the EPA would like more information.

In the case of temporal matching, the central issue is whether a producer must obtain sufficient EACs to match the total electricity demand of the electrolyzer on an annual basis corresponding to an overall emissions rates of 0.45 kg CO_2e/kg H2 or less, or whether the producer must verify that it has obtained an EAC for low carbon generation on a more granular timeframe, such as an hourly or monthly basis, for each time period the electrolyzer is running. In other words, how can book and claim methods for grid-connected systems be developed to reliably claim total energy input emissions are equivalent to a pure off-grid zero-carbon emitting system. Considerations around how grid-based electricity can effectively assure zero-carbon emitting energy inputs as validated by EACs have received greater attention since passage of the IRA. Solutions offered by researchers at Princeton University include requiring new grid-based hydrogen producers to match 100 percent of electricity consumption on an hourly basis with new carbon-free generation (substantiated through EACs with hourly attributes), with an estimated cost impact of $1/kg.[505] Other research analyzing near-term emissions benefits of hourly EAC alignment with respect to IRC section 45V implementation is growing, with some divergent views about the emissions benefits of more precise alignment requirements.[506] Several research papers have focused on the expense, trade-offs, and benefits of phasing in new and hourly EAC alignment requirements.[507] An MIT Energy Initiative Working Paper examined emissions benefits of hourly alignment and supported a '' 'a phased approach'. . . . annual matching in the near term with a re-evaluation leaning towards hourly matching later on in the decade''.[508] A Rhodium Report found that while ''[r]equiring a high degree of stringency across regional, temporal, and additionality variables on day one . . . increases the total subsidized cost of hydrogen production'' in the initial phase of the program, and concludes that ultimately ''policymakers can't ignore the long-term emissions risk'' and recommends, ''[t]o construct emissions guardrails, the IRS can establish target dates for ratcheting up the certainty on key implementation details like a transition to more temporally granular matching. Such phase-in approaches give the hydrogen and power industries the signposts they need to develop the tracking tools, calculation approaches, contract language, and other key elements to assure green hydrogen contributes to decarbonization.'' [509] This analysis did not consider potential system-wide emissions impacts if costs present a near-term barrier to electrolytic hydrogen production, and reformation-based methods continue to dominate hydrogen production market share moving forward. Other research, for example from Princeton, supports hourly time-matching, additionality, and location requirements—arguing that all three pillars are important in ensuring low-GHG outcomes and that additional costs are not unreasonable. Research by Energy Innovation aligns with the Princeton study with respect to locational and additionality requirements and diverges in its recommendation of phasing in hourly EAC requirements by 2026.[510]

wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.

[504] ''How Can Hydrogen Producers Show That They Are ''Clean''?, Resources for the Future, October 27, 2022.

[505] Princeton Citation: Minimizing emissions from grid-based hydrogen production in the United States—IOPscience January 2023.

[506] American Council on Renewable Energy (ACORE), ''Analysis of Hourly & Annual GHG Emissions: Accounting for Hydrogen Production'', April 2023. *acore.org.*

[507] Energy Futures Initiative, ''The Hydrogen Demand Action Plan'', February 2023. *https://energyfuturesinitiative.org/wp-content/uploads/sites/2/2023/02/EFI-Hydrogen-Hubs-FINAL-2-1.pdf.*

[508] MIT Energy Initiative, April 2023 ''Producing hydrogen from electricity: How modeling additionality drives the emissions impact of time-matching requirements'' Anna Cybulsky, Michael Giovanniello, Tim Schittekatte, Dharik S. Mallapragada.

[509] Rhodium Group, ''Scaling Green Hydrogen in a post-IRA World'' March 16, 2023. *https://rhg.com/research/scaling-clean-hydrogen-ira/.*

[510] *https://energyinnovation.org/wp-content/uploads/2023/04/Smart-Design-Of-45V-Hydrogen-Production-Tax-Credit-Will-Reduce-Emissions-And-Grow-The-Industry.pdf.*

The European Commission proposed a phased-in approach to defining what constitutes 'renewable hydrogen' for the European Union (EU). The EU framework includes multiple components including temporal alignment requirements: monthly EAC alignment is required at the onset of the program, and hourly EAC alignment requirements are phased-in by 2030.[511 512] An impact assessment of the temporal alignment requirements is to be completed in 2028 and could impact the timing of the hourly EAC phase-in requirements. The EU hydrogen requirements and conditions will apply to domestic producers and imports and do not expire. EAC alignment requirements impact both new and existing projects. Geographic alignment for EACs is required at the onset of the EU program, whereas vintage requirements necessitating new zero-carbon emitting energy source-based generation, often called 'additional', are phased in after 2028. The EU proposal was released in February and must be approved by the European Parliament and the Council of the EU within four months: amendments to the underlying policy are not permitted. Notably, unlike the United States, the EU has a carbon policy for power sector emissions that could help ensure that additional electricity demand from hydrogen production does not result in additional power sector CO_2 emissions. The EU and stakeholders examining costs and benefits of temporal EAC alignment requirements generally find that hourly EAC alignment is preferred before the 2032 proposed effective date of hydrogen co-firing requirements in this proposed rule, with most converging on or before 2030.[513 514]

The EPA is soliciting comment on requiring EGUs to use geographic and temporal alignment approaches for EAC-related requirements and the appropriate timing and trade-offs of such approaches. The EPA is soliciting comment on the appropriateness of requiring geographic alignment for EACs used in conjunction with energy inputs at the balancing authority level at the onset of the compliance period for BSER in 2032. Similarly, the EPA is soliciting comments on the appropriateness of requiring hourly EAC alignment requirements at the onset of the compliance period for BSER in 2032. Relatedly, the EPA is taking comment on whether any hourly EAC alignment requirements should affect both existing and new projects beginning in 2032, regardless of when a project became operational and a recipient of IRC section 45V credits.

Hourly tracking systems are evolving to meet this need in real time. For example, PJM announced it would introduce EACs with hourly data stamping for low-GHG generators in March 2023. M–RETS, a regional attribute tracking system headquartered in the Midwest, has also introduced the capability to track hourly energy attributes. While several tracking systems are announcing or have started issuing hourly EACs, standardized methods, and nationwide coverage is still developing. Recognizing that the timing of EPA's proposed regulations would not require such tracking systems to be fully functional until the 2030s, the EPA is taking comment on the suitability of emerging and differentiated tracking systems to provide the infrastructure for hourly energy attribute tracking for EGUs complying with low-GHG hydrogen standards. The EPA is also taking comment on the need for energy attribute tracking systems to uniformly approach the issuance, allocation, tracking and retirement of hourly EACs using similar approaches to ensure a common and consistent national practice.

L. Mechanisms To Ensure Use of Actual Low-GHG Hydrogen

The EPA is soliciting comment on appropriate mechanisms to ensure that the low-GHG hydrogen used by EGUs is actually low-GHG, and guard against EGU use of hydrogen that is falsely claimed to be low-GHG hydrogen. The EPA solicits comment on whether EGUs should be required to provide an independent third-party verification that hydrogen the EGU uses to comply with this regulation meets the requirements for low-GHG hydrogen. EPA also solicits comment on whether any such verifying third party must hold an active accreditation from an accrediting body, such as the California Air Resources Board's Low Carbon Fuels Standards Program or the International Standards Organization 14064 Code. EPA seeks comment on any other mechanisms to ensure that hydrogen used by EGUs meets the low-GHG standard and what the remedy should be if an EGU uses hydrogen that is determined not to meet the definition of low-GHG hydrogen.

M. 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 and, for the EGUs relying on the compliance approaches contained in Appendix G of 40 CFR part 75, with the reporting requirements of that Appendix. 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 today's proposal. Because all EGUs are expected to be covered by and included in the ECMPS, minimal, if any, costs for reporting are expected for this proposal. 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 proposes to retain 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 would 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 upon promulgation, this annual cost for recordkeeping will be maintained.

N. Additional Solicitations of Comment and Proposed Requirements

This section includes additional issues the Agency is specifically soliciting comment on. It also provides a summary of some of the key considerations the EPA is soliciting comment on with respect to the

[511] C_2023_1087_1_EN_ACT_part1_v8.pdf. (*europa.eu*)

[512] European Commission, ''Commission sets out rules for renewable hydrogen'' Brussels, February 13, 2023. See: Hydrogen (*europa.eu*), Delegated regulation on Union methodology for RFNBOs. (*europa.eu*)

[513] *https://energyinnovation.org/wp-content/uploads/2023/04/Smart-Design-Of-45V-Hydrogen-Production-Tax-Credit-Will-Reduce-Emissions-And-Grow-The-Industry.pdf.*

[514] April 12, 2023, memorandum, ''How annual matching for the Inflation Reduction Act's (IRA) 45V clean hydrogen tax credit can accelerate progress towards the Biden administration's decarbonization and clean hydrogen goals'' signed by 23 companies, addressed to Treasury Secretary Janet Yellen, Energy Secretary Jennifer Granholm and Senior Advisor to the President for Clean Energy Innovation and Implementation Mr. John Podesta, indicated an openness to examine hourly EAC requirements in 2032 or earlier and asserted, ''recent studies warn that overly stringent temporal matching would hinder the development of clean hydrogen industry.''

proposed CAA section 111(b) requirements.

1. CCS and Co-Firing Low-GHG Hydrogen as BSER for the Base Load Subcategory

As described above, the EPA is proposing to establish two subcategories with different standards for the base load subcategory, each based on a different BSER pathway. The first is based on a BSER of CCS with 90 percent capture by 2035. The second is based on a BSER of co-firing 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent (by volume) by 2038. (Both pathways include efficient equipment and operation and maintenance as an initial component of the BSER.) In other sections of this preamble, the EPA solicits comment on variations in the amount of emissions reduction and the dates for compliance for each pathway.

The EPA believes that if it finalizes a subcategory approach with different standards in which sources may choose between the two standards and BSER pathways, each must achieve environmentally comparable emission reductions. Thus, if the EPA determines based on all of the statutory considerations that CCS with 90 percent capture qualifies as the BSER for base load combustion sources, then co-firing hydrogen could qualify as well only if it also achieves comparable reductions. Because the emissions standards are technology neutral, if the two pathways can achieve the same emissions reductions at the same time, there would be no need to establish separate subcategories and standards as sources could adopt either BSER pathway to meet the standard. But the EPA also believes that these two technologies may achieve comparable emissions reductions at slightly different times, thus potentially necessitating two alternate standards. The EPA solicits comment on the differences in emissions reductions in both scale and time that would result from the two standards and BSER pathways, including how to calculate the different amounts of emission reductions, how to compare them, and what conclusions to draw from those differences. From the perspective of an individual turbine, the proposed co-firing with low-GHG hydrogen-based standard results in earlier emission reductions because it takes effect in 2032, three years before the CCS-based standard, but the low-GHG hydrogen-based standard could also result in fewer total emission reductions because the 90 percent emission rate reduction is not required until 2038, three years after the CCS-based standard. Although early emission reductions have value in addressing climate change, it is the cumulative impact of the emission reductions that is of primary importance given the short time-scale over which those early reductions are occurring. The EPA also solicits comment on the potential benefits of prescribing two separate standards for new base load combustion turbines. Owners and operators of new combustion turbine EGUs are currently pursuing both CCS and co-firing with low-GHG hydrogen as approaches for reducing GHG emissions, and both require the development of infrastructure that may proceed at a different pace and scale and achieve emissions reductions on different timelines with respect to each technology. Although both CCS and co-firing with low-GHG hydrogen are, or are expected to be, broadly available throughout the United States, the EPA solicits comment on whether individual locations where new base load combustion turbines might be constructed might lend themselves more to one technology than the other (based on pipeline availability, proximity to hydrogen production or geologic sequestration sites, *etc.*). The EPA recognizes that the design of CAA section 111—whereby sources decide which emissions controls they use to meet standards of performance—provides sources with operational flexibility so long as they achieve the standard. A subcategory approach, however, may allow the EPA to consider the potentially differing scale and pace at which these technologies can achieve environmentally equivalent emissions reductions and whether there are characteristics of units that make one or the other pathways ''best'' for those types of units.

As an alternative to the proposed approach of two standards and BSER pathways for the base load subcategory, the EPA is soliciting comment on having a single standard, which would be based on CCS with 90 percent capture (along with efficiency as the initial component of the BSER). Under this alternative, the EPA would not establish a separate base load subcategory for combustion turbines that adopt the low-GHG hydrogen co-firing pathway.

The EPA solicits comment on whether finalizing a single, CCS-based standard for the baseload subcategory better reflects the more likely uses of hydrogen as a source of fuel in new combustion turbines. The EPA has proposed a standard for base load combustion turbines that adopt the low-GHG hydrogen co-firing in part because the Agency understands a number of power companies are actively developing combustion turbines that are designed to co-fire hydrogen. However, the Agency recognizes that power companies may ultimately come to utilize low-GHG hydrogen as a storage fuel reserved for intermediate load combustion turbines that support variable renewable generation, rather than for combustion turbines that generate at base load. An approach in which the EPA establishes a single CCS-based second phase standard for base load combustion turbines, along with a second phase standard for intermediate load combustion turbines that is based on low-GHG hydrogen as a component of the BSER, would align with this potential scenario. In addition, if an owner or operator of a new combustion turbine does seek to utilize low-GHG hydrogen for base load generation, a single CCS-based second phase standard for base load combustion turbines would not preclude owners and operators from utilizing low-GHG hydrogen as a means of compliance. Owners/operators could also comply with a CCS-based standard by co-firing 96 percent (by volume) low-GHG hydrogen from the outset of the second phase—rather than the proposed approach that would delay requirements for this level of co-firing until 2038.

2. Co-Firing Low-GHG Hydrogen as BSER for Intermediate Load Combined Cycle and Simple Cycle Subcategories

The EPA is also soliciting comment on subcategorizing intermediate load combustion turbines into an intermediate load combined cycle subcategory and an intermediate load simple cycle subcategory. The BSER for both subcategories would be two components: (1) Highly efficient generation (either combined cycle technology or simple cycle technology, respectively) and (2) co-firing 30 percent (by volume) low-GHG hydrogen, with the first component applying when the source commences operation and the second component applying in the year 2032. Dividing the intermediate load subcategory into these two subcategories would assure that intermediate load combined cycle turbines would have a more stringent standard of performance—that is, expressed in a lower lb CO_2/MWh—than intermediate load simple cycle turbines.

3. Integrated Onsite Generation and Energy Storage

Integrated equipment is currently included as part of the affected facility and the EPA is soliciting comment on the best approach to recognizing the environmental benefits of onsite integrated non-emitting generation and energy storage. The EPA is proposing regulatory text to clarify that the output from integrated renewables is included as output when determining the NSPS emissions rate. The EPA is also proposing that the output from the integrated renewable generation is not included when determining the net electric sales for applicability purposes. In the alternative, the EPA is soliciting 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 would have the impact of increasing the operational flexibility of owners/operators of intermediate load combustion turbines. Renewables typically have much lower 12-operating month capacity factors than the intermediate electric sales threshold so could allow the turbine engine itself to operate at a higher capacity factor while still being considered an intermediate load EGU. Conversely, if the integrated renewables operate at a 12-operating month capacity factor of greater than 20 percent that would reduce the ability of a peaking turbine engine to operate while still remaining in the low load subcategory. However, even if a combustion turbine engine itself were to operate at a capacity factor of less than 20 percent and become categorized as an intermediate load combustion turbine when the output form the integrated renewables are considered, the output from the integrated renewables could lower the emissions rate such that the affected facility would be in compliance with the intermediate load standard of performance.

For integrated energy storage technologies, the EPA is soliciting comment on including the rated output of the energy storage when determining the design efficiency of the affected facility. Similar to integrated renewables, this would increase the flexibility of owner/operators to operate at higher capacity factors while remaining in the low and intermediate load subcategories. The EPA is not proposing that the output from the energy storage be considered in either determining the NSPS emissions rate or as net electric sales for subcategorization applicability purposes. While additional energy storage will allow for integration of additional variable renewable generation, the energy storage devices could be charged using grid supplied electricity that is generated from other types of generation. Therefore, this is not necessarily stored low-GHG electricity.

4. Definition of System Emergency

40 CFR part 60, subpart TTTT (and the proposed 40 CFR part 60, subpart TTTTa) include a provision that electricity sold during hours of operation when a unit is called upon to operate due to a system emergency is not counted toward the percentage electric sales subcategorization threshold.[515] The EPA concluded that this exclusion is necessary to provide flexibility, to maintain system reliability, and to minimize overall costs to the sector (80 FR 64612; October 23, 2015). Some in the regulated community have informed the Agency that additional clarification on a system emergency would need to be determined and documented for compliance purposes. The intent is that the local grid operator would determine which EGUs are essential to maintain grid reliability. The EPA is soliciting comments on amending the definition of system emergency to clarify how it would be implemented. The current text is any abnormal system condition that the RTO, Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

5. Definition of Natural Gas

40 CFR part 60, subpart TTTT (and the proposed 40 CFR part 60, subpart TTTTa) include a definition of natural gas. Natural gas is 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. The EPA is soliciting comment on if the exclusions for specific gases such as landfill gas, etc. are necessary of if they should be deleted. If landfill gas, coal-derived gas, or other gases are processed to meet the methane and heating value content of pipeline quality natural gas they could be mixed into the pipeline network and it is the intent that this mixture be considered natural gas for the purposes of 40 CFR part 60, subpart TTTT and the proposed 40 CFR part 60, subpart TTTTa.

[515] 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.

6. Summary of Solicitation of Comment on BSER Variations

This section summarizes the variations on the subcategories and on BSER for combustion turbines on which the EPA is soliciting comment. It is intended to highlight certain aspects of the proposal the Agency is soliciting comment on and is not intended to cover all aspects of the proposal.

For the low load subcategory, the EPA is soliciting comment on:

- An electric sales threshold of between 15 to 25 percent for all combustion turbines regardless of the specific design efficiency.
- An electric sales threshold based on three quarters of the design efficiency of the combustion turbine. This would result in electric sales thresholds of 18 to 22 percent for simple cycle turbines and 26 to 31 percent for combined cycle turbines.
- Applying a second component of BSER, co-firing 30 percent (by volume) low-GHG hydrogen by 2032.

For the intermediate load subcategory, the EPA is soliciting comment on:

- An efficiency-based standard of performance of between 1,000 to 1,200 lb CO_2/MWh-gross.
- The use of steam injection as part of the first BSER component.
- An electric sales threshold based on 94 percent of the design efficiency. This would result in electric sales thresholds of 29 to 35 percent for simple cycle turbines and 40 to 49 percent for combined cycle turbines.
- A hydrogen co-firing range of 30 to 50 percent by volume as the second component of the BSER.
- Beginning implementation of the second component of the BSER (*i.e.,* hydrogen co-firing) as early as 2030.
- The second component of the BSER would establish separate subcategories

for simple and combined cycle intermediate load combustion turbines, both based on co-firing low-GHG hydrogen.

- Adding a third phase standard based on higher levels of low-GHG hydrogen co-firing by 2038.

For the base load subcategory, the EPA is soliciting comment on:

- An efficiency-based standard of performance of between 730 to 800 lb CO_2/MWh-gross for large combustion turbines.
- An efficiency-based standard of performance of between 850 to 900 lb CO_2/MWh-gross for small combustion turbines.
- Beginning implementation of the second component of the BSER (*i.e.,* CCS or hydrogen co-firing) as early as 2030.
- Beginning implementation of the third component of the co-firing low-GHG hydrogen-based BSER earlier than 2038.
- Whether the third component of the hydrogen BSER should be 96 percent by volume or a lower volume—note that if it is a lower volume that raises issues as to whether the BSER would be appropriate if EPA found that a CCS BSER of 90% for NGCCs was generally applicable
- A hydrogen co-firing range of 30 to 50 percent as the second component of the BSER for combustion turbines co-firing hydrogen.
- A single standard based on either a CCS-based BSER or a co-firing low-GHG-hydrogen based BSER for all base load combustion turbines.
- A carbon capture rate of 90 to 95 percent as the second component of the CCS-based BSER.

O. Compliance Dates

The EPA is proposing that affected sources that commenced construction or reconstruction after May 23, 2023, would need to 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 proposed compliance schedule is consistent with the requirements in section 111 of the CAA.

VIII. Requirements for New, Modified, and Reconstructed Fossil Fuel-Fired Steam Generating Units

A. 2018 NSPS Proposal

The EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015. 80 FR 64510 (October 23, 2015). As discussed in section V.B.2 of this preamble, on December 20, 2018, the EPA proposed amendments that would revise the determination of the BSER for control of GHG emissions from newly constructed coal-fired steam generating units in 40 CFR part 60, subpart TTTT (83 FR 65424; December 20, 2018). The EPA is not reopening for comment or soliciting comment on the 2018 NSPS Proposal, and intends to further address it in a separate action.

1. Additional Amendments

The EPA is proposing multiple less significant amendments. These amendments would be either strictly editorial and would not change any of the requirements of 40 CFR part 60, subpart TTTT or are intended to add additional compliance flexibility. The proposed amendments would also be incorporated into the proposed subpart TTTTa. For additional information on these amendments, see the redline strikeout version of the rule showing the proposed amendments. First, the EPA is proposing editorial amendments to define acronyms the first time they are used in the regulatory text. Second, the EPA is proposing to add International System of Units (SI) equivalent for owners/operators of stationary combustion turbines complying with a heat input-based standard. Third, the EPA is proposing to fix 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 is proposing to add 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 is proposing to update the ANSI, ASME, and ASTM test methods to include more recent versions of the test methods. Finally, the EPA is proposing to add additional compliance flexibilities for EGUs either serving a common electric generator or using a common stack. Specifically, for EGUs serving a common electric generator, the EPA is soliciting comment on whether the Administrator should be able to approve alternate methods for determining energy output. For EGUs using a common stack, the EPA is soliciting comment on whether specific procedures should be added for apportioning the emissions and/or if the Administrator should be able to approve site-specific alternate procedures.

B. Eight-Year Review of NSPS for Fossil Fuel-Fired Steam Generating Units

1. New Construction and Reconstruction

The EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015. As noted in section IV.F, the EPA is not aware of any plans by any companies to undertake new construction of a new fossil fuel-fired steam generating unit, or to undertake a reconstruction of an existing fossil fuel-fired steam generating unit, that would be subject to the 2015 NSPS for steam generating units. Accordingly, the EPA does not consider it necessary, nor a good use of agency resources, to review the NSPS for new construction or reconstruction. See ''New Source Performance Standards (NSPS) Review: Advanced notice of proposed rulemaking,'' 76 FR 65653, 65658 (October 24, 2011) (suggesting it may not be necessary for the EPA to review an NSPS when no new construction, modification, or reconstruction is expected in the source category). Should events change and the EPA learns that companies plan to undertake construction of a new fossil fuel-fired steam generating unit or reconstruction of an existing fossil fuel-fired steam generating unit, the EPA would consider reviewing these standards.

2. Modifications

In the 2015 NSPS, the EPA issued final standards for a steam generating 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. 80 FR 64514 (October 23, 2015).

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 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. *Id.* at 64597–98. The EPA is not reopening 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 would continue to be treated as an existing source that is subject to the CAA section 111(d) requirements being proposed today.

With respect to large modifications, we explained in the 2015 NSPS that they are rare, but there is record evidence indicating that they may occur. *Id.* at 64598. Because the EPA is proposing requirements for existing sources 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 is proposing to revise the BSER for large modifications to mirror the BSER for the subcategory of coal-fired steam generating units that plan to operate past December 31, 2039, 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 proposes 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 X.D.1.a. The EPA is proposing to determine 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. The EPA does not believe there are any considerations relative to a source undertaking a large modification that point towards a control system other than CCS with 90 percent capture qualifying as the BSER. The Agency solicits comment on this issue.

By the same token, the EPA is proposing 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 proposed for existing sources with CCS with 90 percent capture. See section X.D.1.a.iv. Based on this degree of emission limitation, the EPA is proposing that the standard of performance for steam generating units that undertake large modifications after the date of publication of this proposal 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 is proposing that an owner/operator of a modified steam generating unit comply with the proposed emissions rate upon startup of the modified affected facility or the effective date of the final rule, whichever is later. The EPA is proposing the same testing, monitoring, and reporting requirements as are currently in 40 CFR part 60, subpart TTTT.

C. Projects Under Development

Finally, 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.[516] [517] [518] 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.[519]

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 is proposing to remove these projects under the applicability exclusions in subpart TTTT.

IX. Proposed ACE Rule Repeal

The EPA is proposing to repeal the ACE Rule. A general summary of the ACE Rule, including its regulatory and judicial history, is included in section V.B of this preamble. The repeal of the ACE Rule is intended to stand alone and be severable from the other aspects of this rule. The EPA proposes to repeal the ACE Rule on three grounds that together, and each independently, justify the rule's repeal. First, as a policy matter, the EPA believes that the suite of heat rate improvements (HRI) the ACE Rule selected as the BSER should be reexamined and are no longer an appropriate BSER for existing coal-fired EGUs. The EPA concludes that the suite of HRI set forth in the ACE Rule provide

[516] *https://www.gpb.org/news/2010/07/26/judge-rejects-coal-plant-permits.*

[517] *https://www.southernenvironment.org/press-release/court-rules-ga-failed-to-set-safe-limits-on-pollutants-from-coal-plant/.*

[518] *https://permitsearch.gaepd.org/permit.aspx?id=PDF-OP-22139.*

[519] *https://www.southernenvironment.org/wp-content/uploads/legacy/words_docs/EPD_Plant_Washington_Denial_Letter.pdf.*

negligible CO_2 reductions at best and, in many cases, could increase CO_2 emissions because of the rebound effect, as explained in section X.D.5.a. These concerns taken together, along with new evidence, and the EPA's experience in implementing the ACE Rule, cast doubt on the ACE Rule's minimal projected 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, the ACE Rule rejected CCS and natural gas co-firing as the BSER for reasons that no longer apply. This rule should be repealed so that EPA may determine the BSER based on evaluating all the candidate technologies. Since the ACE Rule was promulgated, changes in the power industry, developments in the costs of controls, and new Federal subsidies have made these other technologies more broadly available and less expensive. The EPA is now proposing that these technologies are the BSER for certain subcategories of sources, as described in section X of this preamble.

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],'' but set forth an indeterminate range of values. Thus, 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. Along with this, the ACE Rule also improperly departed from the statutory framework of CAA section 111(d) by categorically precluding States from allowing their sources to comply with standards of performance by trading or averaging. Properly construed, CAA section 111(d) gives States discretion to provide sources with certain compliance flexibilities, including trading or averaging in appropriate circumstances so long as the other requirements of section 111 are met as described below.

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 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 undertaking this task 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 did decide to apply a particular technology to a particular source, the State could determine the level of heat rate improvement from the technology to 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 that 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.[520] 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 sources implemented HRI measures and became more efficient. This phenomenon is explained in more detail in section X.D.5.a.[521]

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, and especially for sources that have limited or no access to natural gas. 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 45Q tax credit, as it then applied, would provide only limited benefit to sources. Id. at 32548–49.

In addition, the ACE Rule interpreted CAA section 111 to preclude States from allowing their sources to trade or average to demonstrate compliance with their standards of performance. Id. at 32556–57.

B. Developments Undermining ACE Rule's Projected Emission Reductions

The EPA's first basis for proposing to repeal the ACE Rule is that there is doubt that the rule would achieve even the limited emissions reductions projected at the time of promulgation if it were implemented now, and implementation could increase CO_2

[520] ACE Rule RIA 3–11, table 3–3.

[521] 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,* EPA–HQ–OAR–2017–0355–26720, and for the ''Illustrative ACE Scenario. *IPM State-Level Emissions: Illustrative ACE Scenario,* EPA–HQ–OAR–2017–0355–26724.

emissions instead. Thus, the EPA concludes that as a matter of the Agency's policy judgment it is appropriate to repeal the rule and evaluate whether other technologies qualify as the BSER given new factual developments. This action is consistent with the Supreme Court's instruction in *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009), where 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).

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.[522] 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. And most sources had already optimized application of HRIs, and so there are fewer opportunities to reduce emissions than previously anticipated.

Second, for a subset of sources, HRI are likely to cause a rebound effect leading to an increase in GHG emissions for those sources for the reasons explained in section X.D.5.a. The estimate of the rebound effect was quite pronounced in the ACE Rule's own analysis—the rule projected that it would increase CO_2 emissions from power plants in 15 States and the District of Columbia. Specifically, the EPA prepared modeling projections to understand the impacts of the ACE Rule. These projections assumed that, consistent with the rule, sources would impose a small degree of efficiency improvements. The modeling showed that the rule would not result in absolute emissions reductions across all affected sources, and some would instead increase absolute emissions. See EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case,* EPA–HQ–OAR–2017–0355–26720 (providing ACE reference case); *IPM State-Level Emissions: Illustrative ACE Scenario,* EPA–HQ–OAR–2017–0355–26724 (providing illustrative scenario).

Despite the fact that 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 costs,'' ''[h]eat rates,'' ''[e]lectric generating capacity,'' and the ''timeline for implementation,'' among other information. 84 FR 32581 (July 8, 2019). 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.

In this context, the data undermining the ACE Rule's limited, projected emission reductions along with the risk that implementation of the rule could increase CO_2 pollution raises doubts that the HRI 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'' questioned whether the BSER selected was in fact the ''best'').

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 was finalized.[523]

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 EPA to propose that HRI are not the BSER for coal-fired power plants.

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 substantially for sources with longer-term operating horizons such that the EPA may determine that these measures satisfy the requirements for the BSER for the source categories identified below. 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 X.D.2.b.ii of this preamble, the costs of natural gas co-firing have substantially decreased, and the EPA is proposing that the costs of co-firing 40 percent by volume natural gas are reasonable for existing coal-fired EGUs in the medium-term subcategory, *i.e.,* units that plan to operate during, in general, the 2032 to 2040 period. In addition, the changed circumstances, including that natural gas is available in greater amounts, and there are fewer coal-fired EGUs, mitigates the concerns the ACE Rule identified about inefficient use of natural gas. See section X.D.2.b.iii(B).

Similarly, the ACE Rule rejected CCS as the BSER on grounds that it was too costly. But as discussed in section X.D.1.b.ii of this preamble, the costs of CCS have substantially declined, partly because of developments in the technology that have lowered capital costs, and partly because the IRA extended and increased the IRC section 45Q tax credit so that it defrays a higher

[522] ACE Rule RIA 3–11, table 3–3.

[523] 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.*

portion of the costs of CCS. Accordingly, for coal-fired EGUs that will continue to operate past 2040, the EPA is proposing that the costs of CCS, which have fallen to approximately $7–$12/MWh, are reasonable.

The 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 X.D.4 of this preamble. And for the BSER for medium-term units, 40 percent natural gas co-firing achieves reductions of 16 percent, as described in section X.D.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 proposing to adopt a new policy and change its regulatory scheme for coal-fired power plants. As discussed in section X.C.3 of this preamble, the EPA is proposing to subcategorize coal-fired power plants according to the time that they will continue to operate. For sources in the imminent-term and near-term subcategories—which include sources that, in general, have federally enforceable commitments to permanently cease operations by 2032 or 2035, respectively—the EPA is proposing that the BSER is routine methods of operation and maintenance, with associated presumptive standards of performance that do not permit an increased emission rate and are not anticipated to have a rebound effect; and the EPA is soliciting comment on whether co-firing some amount of natural gas should be part of the BSER. For sources in the medium-term subcategory—which includes sources that are not in the other subcategories and that have a federally enforceable commitment to permanently cease operations by 2040—the EPA is proposing 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 X.D.2.b.iii(B) of this preamble.

For sources in the long-term subcategory—which includes sources that do not have a federally enforceable commitment to permanently cease operations by 2040—the EPA is proposing 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 X.D.1.c of this preamble.

The EPA is not proposing HRI as the BSER for any coal-fired EGUs. As discussed in section X.D.5.a, the EPA does not consider HRIs an appropriate BSER for the imminent-term and near-term subcategories because these technologies would achieve few, if any, emissions reductions and may increase emissions due to the rebound effect. The EPA is proposing to reject HRI as the BSER for the medium-term and long-term subcategories because HRI could also lead to a 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. For these reasons, the EPA proposes to repeal the ACE Rule.

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

The third independent reason why the EPA is proposing to repeal 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 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 long-standing implementing regulations establish a clear process for the EPA and States to regulate emissions of certain air pollutants from existing sources. ''The statute directs 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,* 142 S. Ct. 2587, 2601 (2022) (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 emissions 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.'' 142 S. Ct. at 2602 (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 long-standing 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). The EPA's revised implementing regulations contain the same requirement. 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 XII.D.2.

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, but was not required to, apply 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, if the State chose. 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, EPA effectively abdicated its responsibilities, and directed each State to determine for its sources what the BSER would be (that is, which HRI technologies should be applied to the source and with what intensity), and, based on that, what the degree of emission limitation achievable by application of the BSER. 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 was 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 29828, 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 9905, 9919 (March 12, 1996) (limiting concentration of non-methane organic compounds from solid waste landfills to 20 parts per million by volume or 98-percent reduction). In the ACE Rule, the EPA 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.

For this reason, the EPA proposes to repeal the ACE Rule. Its 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.

E. ACE Rule's Preclusion of Emissions Trading or Averaging

While not an independent basis for repeal, the ACE Rule also interpreted CAA section 111(d) to bar States from allowing emissions trading or averaging among their sources in all cases, which further shows that the ACE Rule misconstrued section 111(d) and the appropriate roles for the EPA and for the States. A trading program might allocate allowances authorizing a particular level of emissions; a facility would not need to reduce its emissions so long as it traded for sufficient allowances. And an averaging program, for example, might require a group of facilities to reduce their average emissions to a particular level. So long as some facilities reduced their emissions sufficiently below that level, it would not be necessary for every facility to reduce its emissions. *Cf. Chevron U.S.A., Inc.* v. *Natural Res. Def. Council, Inc.,* 467 U.S. 837, 863 n.37 (1984) (explaining the ' ''bubble' or 'netting' concept). CAA section 111(d) accords States discretion in developing State plans, and allows States to include compliance flexibilities like trading or averaging in circumstances the EPA has determined are appropriate, as long as the plan achieves equivalent emissions reductions to the EPA's emission guidelines. The ACE Rule's legal interpretation that CAA section 111(d) always precludes the State from adopting those flexibilities was incorrect.

Under CAA section 111, EPA promulgates emission guidelines that identify the degree of emission limitation achievable through the application of the BSER as determined by the Administrator. Each State must then ''submit to the Administrator a plan'' to achieve the degree of emission limitation identified by EPA. 42 U.S.C. 7411(d)(a). That plan must ''establish[ ] standards of performance for any existing source'' that emits certain air pollutants, and also ''provide[ ] for the implementation and enforcement of such standards of performance.'' Under CAA section 111(a)(1), 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 [BSER].'' Although such standards of performance must ''reflect[ ] the degree of emission limitation achievable through the application of the [BSER],'' 42 U.S.C. 7411(a)(1), States need not compel regulated sources to adopt the particular components of the BSER itself.

The ACE Rule interpreted CAA section 111(a)(1) and (d) to preclude States from allowing their sources to trade or average to demonstrate compliance with their standards of performance. 84 FR 32556–57 (July 8, 2019). The ACE Rule based this interpretation on its view that CAA section 111 limits the type of ''system'' that the EPA may select as the BSER to ''measures that apply at and to an individual source and reduce emissions from that source.'' Id. at 32523–24. The ACE Rule also concluded that the compliance measures the States include in their plans ''should correspond with the approach used to set the standard in the first place,'' and therefore must also be limited to measures that apply at and to an individual source and reduce emissions from that source. Id. at 32556.

In its recently published notice of proposed rulemaking to amend the CAA section 111(d) implementing regulations, the EPA has proposed to determine that the ACE Rule's legal interpretation as to the type of ''system'' that may be selected as a BSER, and the universal prohibition of trading and averaging, was incorrect. ''Implementing Regulations under 40 CFR part 60 Subpart Ba Adoption and Submittal of State Plans for Designated Facilities: Proposed Rule,'' 87 FR 79176, 79207–79208 (December 23, 2022). As discussed in that document, no provision in CAA section 111(d), by its terms, precludes States from having flexibility in determining which measures will best achieve compliance with the EPA's emission guidelines.

Specifically, the plain language of section 111(d) does not affirmatively bar States from considering averaging and trading as a compliance measure where appropriate for a particular emission guideline. Under section 111(d)(1), States must ''establish[ ],'' ''implement[ ],'' and ''enforce[ ]'' ''standards of performance for any existing source.'' A State plan that specifies what each existing source must do to satisfy plan requirements is naturally characterized as establishing ''standards of performance for [each] existing source,'' even if measures like trading and averaging are identified as potential means of compliance. Trading and averaging programs may be appropriate as a policy matter as well because, in some circumstances, they can help to ensure that costs are reasonable by enabling market force to identify the facilities whose emissions can be reduced most cost-effectively. Nothing in the text of section 111 precludes States from considering a source's acquisition of allowances in implementing and enforcing a standard of performance for that particular source, so long as the State plan achieves the required level of emission reductions.

Further supporting this statutory interpretation, section 111(d) requires a ''procedure similar to that provided by Section 7410.'' Consideration of the section 110 framework reinforces the absence of any mandate that States consider only compliance measures that apply at and to an individual source. ''States have 'wide discretion' in formulating their plans'' under section 110. *Alaska Dep't of Envtl. Conservation* v. *EPA,* 540 U.S. 461, 470 (2004) (citation omitted); see *Union Elec. Co.* v. *EPA,* 427 U.S. 246, 269 (1976) (''Congress plainly left with the States, so long as the national standards were met, the power to deter-mine which sources would be burdened by regulation and to what extent.''); *Train* v. *Natural Res. Def. Council, Inc.,* 421 U.S. 60, 79 (1975) (''[S]o long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation.''). Exercising that discretion, States have included measures that do not apply at or to a source in their section 1410 plans. For example, States have employed NO_X and SO_2 trading programs to comply with section 7410(a)(2)(D)(i)(I), the ''Good Neighbor Provision.'' Section 110 thus does not distinguish between measures that do or don't apply at or to a source for compliance, and there is no sound reason to read section 111's comparably broad language differently.

Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests States with substantial discretion. As the U.S. Supreme Court has explained, CAA section 111(d) ''envisions extensive cooperation between federal and state authorities, generally permitting each State to take the first cut at determining how best to achieve EPA emissions standards within its domain.'' *American Elec. Power Co.* v. *Connecticut,* 564 U.S. 410, 428 (2011) (citations omitted).

To be sure, as discussed above, EPA retains an important role in reviewing State plans for adequacy. Under 111(d), each State must ''submit to the Administrator a plan'' to achieve the degree of emission limitation identified by EPA. That plan must ''establish[ ] standards of performance for any existing source for [the] air pollutant'' and also ''provide[ ] for the implementation and enforcement of such standards of performance.'' Id. If a State elects not to submit a plan, or submits a plan that EPA does not find ''satisfactory,'' EPA must promulgate a plan that establishes Federal standards of performance for the State's existing sources. 42 U.S.C. 7411(d)(2)(A). Thus, the flexibility that CAA section 111(d) grants to States in adopting measures for their State plans is not unfettered. As the Supreme Court stated in *West Virginia,* ''The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved.'' 142 S. Ct. at 2602. State plans then must contain ''emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA.'' Id. Thus, EPA bears the burden of ensuring that the permissible level of pollution is not exceeded by any State plan. When a compliance flexibility compromises the ability of the State plan to achieve the necessary emission reductions, then the EPA may reasonably preclude reliance on such measures, or otherwise conclude that the State plan is not satisfactory.

Thus, the EPA proposed to disagree with the ACE Rule's conclusion that State plan compliance measures must always apply at and to an individual source and reduce emissions of that source. As noted in section V.B.6, the U.S. Supreme Court in *West Virginia* v. *EPA,* 142 S. Ct. 2587 (2022), did not address the scope of the States' compliance flexibilities in developing State plans. The Court also declined to address whether CAA section 111 limits the type of ''system'' the EPA may consider to measures that apply substantially at and to an individual source. See id. at 2615.

For these reasons, in its notice of proposed rulemaking to amend the CAA section 111(d) implementing regulations, EPA proposes to interpret CAA section 111 as permitting each State to adopt measures that allow its sources to meet their emissions limits in the aggregate, when the EPA determines, in any particular emission guideline, that it is appropriate to do so, given, inter alia, the pollution, sources, and standards of performance at issue. Thus, it is the EPA's proposed position that CAA 111(d) authorizes the EPA to approve State plans under particular emission guidelines that achieve the requisite emission limitation through the aggregate reductions from those sources, including through trading or averaging where appropriate for a particular emission guideline and consistent with the intended environmental outcomes of the guideline. As discussed in section XII.E, the EPA is proposing to allow trading and averaging under the proposed emission guidelines and requesting comment on whether and how such compliance mechanisms could be implemented to ensure equivalency with the emission reductions that would be achieved if each affected source was achieving its applicable standard of performance.

The ACE Rule's flawed legal interpretation that CAA section 111(d) universally precludes States from emissions trading is incorrect and adds to EPA's rationale for proposing to repeal the rule.

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

A. Overview

In this section of the preamble, the EPA explains the basis for its proposed emission guidelines for GHG emissions from existing fossil fuel-fired steam generating units for States' use in plan development. This includes proposing different subcategories of designated facilities, the BSER for each subcategory, and the degree of emission limitation achievable by application of each proposed BSER. The EPA is proposing subcategories for steam generating units based on the type and amount of fossil fuel (*i.e.,* coal, oil, and natural gas) fired in the unit.

For existing coal-fired steam generating units that plan to operate in the long-term, the EPA is proposing CCS with 90 percent capture as BSER, based on a review of emission control technologies detailed further in this section of the preamble and accompanying TSDs, available in the docket. The EPA is soliciting comment on a range of maximum capture rates (90 to 95 percent or greater) and, to potentially account for the amount of time the capture equipment operates relative to operation of the steam generating unit, a slightly lower achievable degree of emission limitation (75 to 90 percent reduction in average annual emission rate, defined in terms of pounds of CO_2 per unit of generation).

During the EPA's engagement with stakeholders to inform this proposed rule, industry stakeholders noted that many coal-fired sources have plans to permanently cease operation in the coming years, and that GHG control technologies might not be cost reasonable for those units operating on shorter timeframes. These stakeholders recommended that the emission guidelines account for industry plans for permanently ceasing operation of coal-fired steam generating units by establishing a ''subcategory pathway'' with less stringent requirements.

Consistent with this stakeholder input, the EPA proposes to provide subcategories for coal-fired steam generating units planning to permanently cease operations in the 2030s. The EPA recognizes that the cost reasonableness of GHG control technology options differ depending on a coal-fired steam generating unit's expected operating time horizon. Accordingly, the EPA is proposing to divide the subcategory for coal-fired units into additional subcategories based on operating horizon (*i.e.,* dates for electing to permanently cease operation) and, for one of those subcategories, load level (*i.e.,* annual capacity factor), with a separate BSER and degree of emission limitation corresponding to each subcategory. For long-term coal-fired units, the EPA is proposing that CCS satisfies the BSER criteria, as noted above. For medium-term units, the EPA is proposing natural gas co-firing at 40 percent of annual heat input as BSER. The EPA is soliciting comment on the percent of natural gas co-firing from 30 to 50 percent and the degree of emission limitation defined by a reduction in emission rate from 12 to 20 percent. For imminent-term and near-term coal-fired steam generating units, the EPA is proposing a BSER of routine methods of operation and maintenance. Because of differences in performance between units, the EPA is proposing to determine the associated degree of emission limitation as no increase in emission rate. For imminent-term and near-term coal-fired steam generating units, the EPA is also soliciting comment on a potential BSER based on low levels of natural gas co-firing.

For natural gas- and oil-fired steam generating units, the EPA is proposing a BSER of routine methods of operation and maintenance and a degree of emission limitation of no increase in emission rate. Further, the EPA is proposing to divide subcategories for oil- and natural gas-fired units based on capacity and, in some cases, geographic location. Because natural gas- and oil-fired steam generating units with similar annual capacity factors perform similarly to one another, the EPA is proposing presumptive standards of performance of 1,300 lb CO_2/MWh-gross for base load units (*i.e.,* those with annual capacity factors greater than 45 percent) and 1,500 lb CO_2/MWh-gross for intermediate load units (*i.e.,* those with annual capacity factors between 8 and 45 percent). Because natural gas- and oil-fired steam generating units with low load have large variations in emission rate, the EPA is not proposing a BSER or degree of emission limitation for those units in this action. However, the EPA is soliciting comment on a potential BSER of ''uniform fuels'' and degree of emission limitation defined on a heat input basis by 120 to 130 lb CO_2/MMBtu for low load natural gas-fired steam generating units and 150 to 170 lb CO_2/MMBtu for low load oil-fired steam generating units. Also, because non-continental oil-fired steam generating units operate at intermediate and base load, and because there are relatively few of those units for which to define a limit on a fleet-wide basis, the EPA is proposing a degree of emission limitation for those units of no increase in emission rate and presumptive standards based on unit-specific emission rates, as detailed in section XII of this preamble. The EPA is soliciting comment on ranges of annual capacity factors to define the thresholds between the load levels and ranges in the degrees of emission limitation, as specified in section X.E of this preamble.

It should be noted that the EPA is proposing a compliance date of January 1, 2030, as discussed in section XII of this preamble on State plan development.

The remainder of this section is organized into the following subsections. Subsection B describes the proposed applicability requirements for existing steam generating units. Subsection C provides the explanation for the proposed subcategories. Subsection D contains, for coal-fired steam generating units, a summary of the systems considered for the BSER, detailed discussion of the systems and other options considered, and explanation and justification for the determination of BSER and degree of emission limitation. Subsection E contains, for natural gas- and oil-fired steam generating units, a summary of the systems considered for the BSER, detailed discussion of the systems and other options considered, and explanation and justification for the determination of BSER and degree of emission limitation.

B. Applicability Requirements for Existing Fossil Fuel-Fired Steam Generating Units

For the emission guidelines, the EPA is proposing that a designated facility [524] 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

[524] 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).

before January 8, 2014;[525] (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 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.[526] For this action, 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 this proposal concerning applicability is the same as that for 40 CFR part 60, subpart TTTT (80 FR 64543–44; October 23, 2015). The EPA incorporates 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 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. Moreover, because the EPA is now proposing revised standards of performance for coal-fired steam generating units that undertake a modification, a modified source would be considered ''new,'' and therefore not subject to these emission guidelines, if the modification occurs after the date this proposal is published in the **Federal Register**. Any source 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 proposing to include in the applicability requirements of the emission guidelines the same exemptions as discussed for 40 CFR part 60, subpart TTTT in section VII.E.1 of this preamble. Designated EGUs that may be excluded from 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) 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 steam generating unit(s), where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit) 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; or (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. The EPA solicits comment on the proposed definition of ''designated facility'' and applicability exemptions for fossil fuel-fired steam generating units.

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 VII.E.1 of this preamble. The exemptions listed above at (2), (3), and (8) are exemptions the EPA is proposing to revise for 40 CFR part 60, subpart TTTT, and the rationale for proposing the exemptions is in section VII.E.1 of this preamble. For consistency with the applicability requirements in 40 CFR part 60, subpart TTTT, we are proposing these same exemptions for the applicability of the emission guidelines.

The EPA is, in general, proposing the same emission guidelines for fossil fuel-fired steam generating units 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 is proposing for comparable units in the contiguous 48 States. However, units in non-continental and non-contiguous areas operate on small, isolated electric grids, may operate differently from units in the contiguous 48 States, and may have limited access to certain components of the proposed BSER due to their uniquely isolated geography or infrastructure. Therefore, the EPA is soliciting comment on the proposed BSER and degrees of emission limitation for units in non-continental and non-contiguous areas, and the EPA is soliciting comment on whether those units in non-continental and non-contiguous areas should be subject to different, if any, requirements.

The EPA notes that existing IGCC units are included in the proposed applicability requirements and that, in section X.C.1 of this preamble, the EPA is proposing to include 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 X.D of this preamble, the proposed BSER for coal-fired steam generating units includes co-firing natural gas and CCS, depending on their operating horizon. 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 are 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 capture process or a physical absorption capture process. For these reasons, the EPA is not proposing to distinguish 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.[527]

C. Subcategorization of Fossil Fuel-Fired Steam Generating Units

Steam generating units can have a broad range of technical and operational differences. Based on these differences, they may be subcategorized, and different BSER and degrees of emission limitation may be applicable to different subcategories. Subcategorizing allows for determining the most appropriate

[525] 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.

[526] 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.

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

control requirements for a given class of steam generating unit. Therefore, the EPA is proposing subcategories for steam generating units based on fossil fuel type, operating horizon and load level, and is proposing different BSER and degrees of emission limitation for those different subcategories. The EPA notes that in section XII.B of this preamble comment is solicited on the compliance deadline (*i.e.,* January 1, 2030), for imminent-term and near-term coal-fired steam generating units, and different subcategories of natural gas- and oil-fired steam generating units.

1. Subcategorization by Fossil Fuel Type

In this action, the EPA is proposing 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 subcategory definitions proposed for these emission guidelines are based on the definitions in 40 CFR part 63, subpart UUUUU, and using the fossil fuel definitions in 40 CFR part 60, subpart TTTT.

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 the 3 calendar years prior to the proposed compliance deadline (*i.e.,* January 1, 2030), or for more than 15.0 percent of the annual heat input during any one of those calendar years, 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 and that burns oil for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to the proposed compliance deadline (*i.e.,* January 1, 2030), or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal 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 and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to the proposed compliance deadline (*i.e.,* January 1, 2030), or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

2. Subcategorization of Natural Gas- and Oil-Fired Steam Generating Units by Load Level

The EPA is also proposing additional subcategories for oil-fired and natural gas-fired steam generating units, based on 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. In addition, the EPA is soliciting comment on a range from 5 to 20 percent to define the threshold value between low and intermediate load and a range from 40 to 50 percent to define the threshold value between intermediate and base load. Because non-continental oil-fired units may operate differently, the EPA is proposing a separate subcategory for intermediate and base load non-continental oil-fired units. The rationale for the proposed load thresholds and other subcategories is detailed in the description of the BSER for oil- and natural gas-fired steam generating units in section X.E of this preamble.

3. Subcategorization of Coal-Fired Steam Generating Units by Operating Horizon and Load Level

The EPA is proposing CCS with 90 percent capture as BSER for existing coal-fired steam generating units that will operate in the long-term (*i.e.,* those that intend to operate on or after January 1, 2040), as detailed in section X.D of this preamble. CCS is adequately demonstrated at coal-fired steam generating units, is cost reasonable, achieves meaningful reductions in GHG emissions, and meets the other criteria for the BSER. The EPA is soliciting comment on a range of maximum capture rates (90 to 95 percent or greater) and, to potentially account for the amount of time the capture equipment operates relative to operation of the steam generating unit, a slightly lower achievable degree of emission limitation (75 to 90 percent reduction in average annual emission rate, defined in terms of pounds of CO_2 per unit of generation).

During the EPA's engagement with stakeholders to inform this proposed rule, industry commenters to the pre-proposal docket noted that many sources have plans to permanently cease operation in the coming years, and that GHG control technologies might not be cost reasonable for those units operating on shorter timeframes. Further, industry stakeholders recommended that the emission guidelines account for industry plans for permanently ceasing operation of coal-fired steam generating units by establishing a ''subcategory pathway.'' Specifically, industry stakeholders requested that, ''[The] EPA should provide a subcategory pathway for units to decommission/repower into the early 2030s, which would include enforceable shutdown obligations, as part of an approach to existing unit guidelines.'' The stakeholders cited, as a precedent, the EPA's creation of—

> targeted subcategories for unit closures in other contexts, most notably the cessation of coal subcategory in the 2020 Clean Water Act (CWA) steam electric effluent guidelines . . . that allows for decommissioning/repowering by December 31, 2028. This subcategory allows those facilities that have already filed closure commitments to continue on a path to decommission/repower these assets without installing additional control equipment that could extend the lives of these units to support cost recovery.

EPA–HQ–OAR–2022–0723–0024. In subsequent comment, industry stakeholders reiterated that, ''[The] EPA should proactively include a subcategory that allows for units to opt-in to a federally enforceable retirement commitment as part of compliance with regulations for existing sources under CAA section 111(d).'' EPA–HQ–OAR–2022–0723–0038. Thus, industry stakeholders recommended that EPA allow existing sources that are on a path to near term retirement to continue on that path without having to install additional control equipment.

The proposed emission guidelines are aligned with this recommendation. Many fossil fuel-fired steam generating units have plans to cease operations, are part of utilities with commitments to net zero power by certain dates, or are in States or localities with commitments to net zero power by certain dates. Over one-third of existing coal-fired steam generating capacity has planned to cease operation by 2032, and approximately half of the capacity has planned to cease operations by 2040.[528] These plans are part of the industry trend, described in section IV.F and IV.I, in which owners and operators of the nation's coal fleet, much of it aging, are replacing their units with natural gas combustion turbines and, increasingly, renewable energy.

As industry stakeholders have pointed out, in previous rulemakings, the EPA has allowed coal-fired EGUs with plans to voluntarily cease operations in the near future to continue with their plans without having to install pollution control equipment. In addition to the 2020 CWA steam electric

[528] See the *Power Sector Trends* TSD.

effluent guidelines these stakeholders cite, the EPA has also approved regional haze State implementation plans in which coal-fired EGUs that voluntarily committed to cease operations by a certain date were not subject to more stringent controls.[529]

The EPA proposes to take the approach requested by industry stakeholders in this rulemaking. The EPA recognizes that the cost reasonableness of GHG control technology options differ depending on a coal-fired steam generating unit's expected operating time horizon. Certain technologies that are cost reasonable for EGUs that intend to operate for the long term are less cost reasonable for EGUs with shorter operating horizons because of shorter amortization periods and, for CCS, less time to utilize the IRC section 45Q tax credit.

Accordingly, the EPA is proposing to divide the subcategory for coal-fired units into additional subcategories based on operating horizon (*i.e.,* dates for electing to permanently cease operation) and, for one of those subcategories, load level (*i.e.,* annual capacity factor), with a separate BSER and degree of emission limitation corresponding to each subcategory. Coal-fired steam generating units would be able to opt into these subcategories if they elect to commit to permanently ceasing operations by a certain date (and, in the case of one subcategory, elect to commit to an annual capacity factor limitation), and also elect to make such commitments federally enforceable and continuing by including them in the State plan.

Specifically, the EPA is proposing four subcategories for steam generating units by operating horizon (*i.e.,* enforceable commitments to permanently cease operations) and, in one case, by load level (*i.e.,* annual capacity factor) as well. ''Imminent-term'' steam generating units are those that (1) Have elected to commit to permanently cease operations prior to January 1, 2032, and (2) elect to make that commitment federally enforceable and continuing by having it included in the State plan.[530] ''Near-term'' steam generating units are those that (1) Have elected to commit to permanently cease operations by December 31, 2034, as well as to adopt an annual capacity factor limit of 20 percent, and (2) elect to make both conditions federally enforceable and continuing by having them included in the State plan. ''Medium-term'' steam generating units are those that (1) Operate after December 31, 2031, (2) have elected to commit to permanently cease operations prior to January 1, 2040, (3) elect to make that commitment federally enforceable and continuing by having it included in the State plan, and (4) do not meet the definition of near-term units. ''Long-term'' steam generating units are those that have not elected to commit to permanently cease operations prior to January 1, 2040. Details regarding the implementation of subcategories in State plans are available in section XII.D of this preamble.

The EPA is proposing the imminent-term subcategory based on a 2-year operating horizon from the proposed compliance deadline (January 1, 2030, see section XII.B for additional details). This proposed subcategory is designed to accommodate units with operating horizons short enough that no additional CO_2 control measures would be cost reasonable. The EPA is proposing the near-term subcategory to provide an alternative option for units that intend to operate for a slightly longer horizon but as peaking units, *i.e.,* that intend to run at lower load levels. The load level of 20 percent for the near-term subcategory is based on spreading an average 2 years of generation (*i.e.,* 50 percent in each year, a typical load level) that would occur under the imminent-term subcategory over the 5-year operating horizon of the near-term subcategory. The EPA also solicits comment on whether the existence of the near-term subcategory makes the imminent-term subcategory unnecessary. More specifically, the EPA requests comment on the potential to remove the imminent-term subcategory, which as proposed includes coal-fired steam generating units that have elected to commit to permanently cease operations prior to January 1, 2032. The EPA is considering an option in which these units would instead be included in the near-term subcategory (units that have elected to commit to permanently cease operations before January 1, 2035 and commit to adopt an annual capacity factor limit of 20 percent) or the medium-term subcategory (units that have elected to commit to permanently cease operations before January 1, 2040 and that are not near-term units). The EPA further requests comment on an alternative, modified approach for units in the imminent-term subcategory that could take into account how units intending to cease operations operate in practice in the period leading up to such cessation. For instance, in their last few years of operation, those units may operate less than they have historically operated, lowering their total CO_2 mass emissions, but at the same time raising their emission rate (because lower utilization may result in lower efficiency). The EPA solicits comment on whether it would be appropriate for the imminent-term units' standards of performance to reflect the reduced utilization and higher emission rates through the use of an annual mass emission limitation. Such a limitation would account for lower utilization, but also allow greater flexibility with regard to hourly emission rate.

The EPA is proposing the 10-year operating horizon (*i.e.,* January 1, 2040) as the threshold between medium-term and long-term subcategories because long-term units will have a longer amortization period and may be better able to fully utilize the IRC section 45Q tax credit. For the analysis of BSER costs of CCS for long-term units, the EPA assumes a 12-year amortization period as this is commensurate with the time period the IRC section 45Q tax credit would be available. Based on the cost analysis performed under that assumption, the EPA is proposing the costs of CCS for long-term coal-fired units are reasonable, as detailed in section X.D.1.a.ii of this preamble. To support the 10-year operating horizon threshold, the costs for a 10-year amortization period are shown here. For a 10-year amortization period, assuming a 50 percent capacity factor, costs of CCS for a representative unit are $31/ton of CO_2 reduced or $27/MWh of generation. Assuming a 70 percent capacity factor, costs of CCS for a representative unit are $6/ton of CO_2

[529] *See, e.g.,* 76 FR 12651, 12660–63 (March 8, 2011) (best available retrofit technology requirements for Oregon source based on enforceable retirement that were to be made federally enforceable in state implementation plan).

[530] Operating conditions that are within the control of a source must, under a range of CAA programs, be made federally enforceable in order for a source to rely on them as the basis for a less stringent standard. See, *e.g.,* 76 FR 12651, 12660–63 (March 8, 2011) (best available retrofit technology requirements for Oregon source based on enforceable retirement that were to be made federally enforceable in state implementation plan); Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 34, EPA–457/B–19–003, August 2019 (to the extent a state relies 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); 84 FR 32520, 32558 (July 8, 2019) (to the extent a state relies on a source's retirement date for a standard of performance under 111(d), that date must be included in the state plan and will thus be made federally enforceable); 87 FR 79176, 79200–01 (December 23, 2022) (proposed revisions to CAA section 111(d) implementing regulations would require States to include operating conditions, including retirements, in their state plans whenever the state seeks to rely on that operating condition as the basis for a less stringent standard).

reduced or $5/MWh of generation. For the population of units planning to operate on or after January 1, 2030, the fleet average costs assuming a 50 percent capacity factor are $24/ton of CO_2 reduced or $22/MWh. For the population of units planning to operate on or after January 1, 2030, the fleet average costs assuming a 70 percent capacity factor are −$3/ton of CO_2 reduced or −$2/MWh. Costs vary depending on capacity factor assumptions, but are in either case generally comparable to the costs detailed in section VII.F.3.b.iii(B)(5) of this preamble of other controls on EGUs ($10.60 to $29.00/MWh) and less than 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 is soliciting comment on the dates and load levels used to define the coal-fired subcategories and is seeking data and analysis on the impact of those alternative dates and load levels on the compliance requirements. As noted in section X.D.1.a.ii(C) of this preamble, the costs for CCS may be reasonable for units with amortization periods as short as 8 years. Therefore, the EPA is specifically soliciting comment on an operating horizon of between 8 and 10 years (*i.e.,* January 1, 2038, to January 1, 2040) to define the date for the threshold between medium-term and long-term coal-fired steam generating units.

4. Legal Basis for Subcategorization

As noted in section V of this preamble, the EPA has broad authority under CAA section 111(d) to identify subcategories. As also noted in section V, 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 long-standing regulations under CAA section 111(d) explicitly recognize that subcategorizing may be appropriate for sources based on the ''costs of control.'' [531] Subcategorizing on the basis of operating horizon is consistent with a central characteristic of the coal-fired power industry that is relevant for determining the cost reasonableness of control requirements: A large percentage of the industry has announced, or is expected to announce, dates for ceasing operation, and the fact that many coal-fired steam generating units intend to cease operation affects what controls are ''best'' for different subcategories. 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 and the controls will thereby be less cost-effective and therefore may not qualify as the BSER.[532]

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 X.C of this preamble. For 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 64510, 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.,* because the costs are spread over less product produced.

The second is fuel type, as also noted in section X.C 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 fuel type presents an additional analogy to the present case of subcategorizing on the basis of the length of time when the source will continue to operate because this timeframe is tantamount to the length of time when 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.'' [533]

It should be noted that subcategorizing on the basis of operating horizon does not preclude a State from considering RULOF in applying a standard of performance to a particular source. 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. 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 the characteristics of a particular source that may differ from the assumptions EPA made in determining BSER generally. As noted above, the EPA is proposing these subcategories in response to requests by power sector representatives that this rule accommodate the fact that there is a class of sources that plans 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

[531] 40 CFR 60.22(b)(5), 60.22a(b)(5).

[532] 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).

[533] 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)).

address as described in section XII.D.2 of this preamble.

D. Determination of BSER for Coal-Fired Steam Generating Units

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. This section of the preamble discusses each of these alternatives, based on the criteria described in section V.C of this preamble.

The EPA is proposing CCS with 90 percent capture as BSER for long-term coal-fired steam generating units, that is, ones that are expected to continue to operate past 2039, because CCS can achieve an appropriate amount of emission reductions and satisfies the other BSER criteria. Because CCS is less cost reasonable for EGUs that do not plan to operate in the long term, the EPA is proposing other measures as BSER for the other subcategories of existing coal-fired steam generating units.

Specifically, for medium-term units, that is, ones that have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2040, and are not near-term units, the EPA is proposing a BSER of 40 percent natural gas co-firing on a heat input basis. However, the EPA is taking comment on the operating horizon (*i.e.,* between 8 and 10 years, instead of the proposed 10-year operating horizon) that defines the threshold date between medium-term and long-term coal-fired steam generating units, and it is possible that the costs of CCS may be considered reasonable for some portion of the units that may be covered by the medium-term subcategory as proposed.

For imminent-term and near-term units, that is, ones that have elected to commit to permanently cease operations before January 1, 2032, and between December 31, 2031, and January 1, 2035, coupled with an annual capacity factor limit, respectively, the EPA is proposing a BSER of routine methods of operation and maintenance that maintain current emission rates. The EPA is also soliciting comment on a potential BSER based on low levels of natural gas co-firing for imminent- and near-term units.

1. Long-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA evaluates CCS and natural gas co-firing as potential BSER for long-term coal-fired steam generating units.

The EPA is proposing CCS with 90 percent capture of CO_2 at the stack as BSER for long-term coal-fired steam generating units. The Agency is taking comment on the range of the amount of capture of CO_2 from 90 to 95 percent or greater. CCS 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, as indicated by the facts that it has been operated at scale and is widely applicable to 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 and energy requirements of CCS are not unreasonably adverse. These factors provide the basis for proposing CCS as BSER for these sources. In addition, determining CCS as the BSER promotes this useful GHG emission control technology.

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 reasonable, 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 proposing natural gas co-firing as the BSER for these units.

a. CCS

In this section of the preamble, the EPA evaluates the use of CCS as the BSER for existing long-term coal-fired steam generating units. This section incorporates by reference the parts of section VII.F.3.b.iii of this preamble that discuss the aspects of CCS that are common to new combustion turbines and existing steam generating units. This section also discusses additional aspects of CCS that are relevant for existing steam generating units and, in particular, long-term units.

i. Adequately Demonstrated

The EPA is proposing that CCS is technically feasible and has been adequately demonstrated, based on the utilization of the technology at existing coal-fired steam generating units and industrial sources in addition to combustion turbines. While the EPA would propose that CCS is adequately demonstrated on those bases alone, this determination is further corroborated by EPAct05-assisted projects.

The fundamental CCS technology has been in existence for decades, and the industry has extensive experience with and knowledge about it. Indeed, even without the requirements proposed here, the EPA projects that 9 GW of coal-fired steam generating units would apply CCS by 2030. Thus, the EPA will explain how existing and planned fossil fuel-fired electric power plants and other industrial projects that have installed or expect to install some or all of the components of CCS technology support the EPA's proposed determination that CCS is adequately demonstrated for existing coal-fired power plants, and the EPA will explain how EPAct05-assisted projects support that proposed determination, consistent with the legal interpretation of the EPAct05 in section VII.F.3.b.iii(A) of this preamble.

(A) CO_2 Capture Technology

The technology of CO_2 capture, in general, is detailed in accompanying TSDs (available in the docket) and in section VII.F.3.b.iii of this preamble. As noted there, solvent-based (*i.e.,* amine-based) post-combustion CO_2 capture is the technology that is most applicable at existing coal-fired steam generating units. Technology considerations specific to existing coal-fired steam generating units, including energy demands, non-GHG emissions, and water use and siting, are discussed in section X.D.1.a.iii of this preamble. As detailed in section VII.F.3.b.iii(A) of this preamble, the CO_2 capture component of CCS has been demonstrated at existing coal-fired steam generating units, industrial processes, and existing combustion turbines. In particular, SaskPower's Boundary Dam Unit 3 has demonstrated capture rates of 90 percent of the CO_2 in flue gas using solvent-based post-combustion capture retrofitted to existing coal-fired steam generating units. While the EPA would propose that the CO_2 capture component of CCS is adequately demonstrated on the basis of Boundary Dam Unit 3 alone, CO_2 capture has been further demonstrated at other coal-fired steam generating units (CO_2 capture from slipstreams of AES's Warrior Run and Shady Point) and industrial processes (*e.g.,* Quest CO_2 capture project), detailed descriptions of which are provided in section VII.F.3.b.iii(A)(2) of this preamble. The core technology of CO_2 capture applied to combustion turbines is similar to that of coal-fired steam generating units (*i.e.,* both may use amine solvent-based methods); therefore the demonstration of CO_2 capture at combustion turbines (*e.g.,* the Bellingham, Massachusetts, combined cycle unit), as detailed in section VII.F.3.b.iii(A)(3) of this preamble, provide additional support for the adequate demonstration of CO_2 capture for coal-fired steam generating units. Finally, EPAct05-assisted CO_2 capture projects (*e.g.,* Petra Nova) further corroborate the adequate demonstration of CO_2 capture.

(B) CO_2 Transport

As discussed in section VII.F.3.b.iii 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.[534] Other modes of CO_2 transportation also exist.

Based on data from DOE/NETL studies of storage resources, 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.[535] Additionally, of the coal-fired steam generating units with planned operation during or after 2030, 90 percent are located within 100 km of one or more types of sequestration formations, including deep saline, unmineable coal seams, and oil and gas reservoirs. This distance is consistent with the distances referenced in studies that form the basis for transport cost estimates in this proposal.[536 537] As noted in section VII.F.3.b.iii(A)(5) of this preamble, areas without reasonable access to pipelines for geologic sequestration can transport CO_2 to sequestration sites via other transportation modes such as ship, road tanker, or rail tank cars.

(C) Geologic Sequestration of CO_2

Geologic sequestration (*i.e.,* the long-term containment of a CO_2 stream in subsurface geologic formations) is well proven and broadly available throughout the U.S. Geologic sequestration is based on a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. As discussed in section VII.F.3.a.iii 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 Class VI well regulations, which are under the authority of SDWA, and the GHGRP, under the authority of the CAA.

Geologic sequestration potential for CO_2 is 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.

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.[538] These data show that of the coal-fired steam generating units with planned operation during or after 2030, 60 percent are located within the boundary of a saline reservoir, 77 percent are located within 40 miles (80 km) of the boundary of a saline reservoir, and 82 percent are located within 62 miles (100 km) of a saline reservoir. Additionally, of the coal-fired steam generating units with planned operation during or after 2030, 90 percent are located within 100 km of any of the considered formations, including deep saline, unmineable coal seams, and oil and gas reservoirs.[539 540] As noted in section VII.F.3.b.iii(A)(5) of this preamble, areas without reasonable access to pipelines for geologic sequestration can transport CO_2 to sequestration sites via other transportation modes such as ship, road tanker, or rail tank cars.

ii. Costs

The EPA has analyzed the costs of CCS for existing coal-fired long-term sources, including costs for CO_2 capture, transport, and sequestration. The EPA is proposing that this analysis demonstrates that the costs of CCS for these sources are reasonable. The EPA also evaluated costs assuming a higher capacity factor of 70 percent (resulting in lower costs) and different amortization periods, as discussed in section X.D.1.a.ii(C) of this preamble. The EPA is soliciting comment on the assumptions in the cost analysis, particularly with respect to the capacity factor assumption. As elsewhere in this section of the preamble, costs are presented in 2019 dollars.

The EPA assessed costs of CCS for a reference unit as well as the average cost for the fleet of coal-fired steam generating units with planned operation during or after 2030. The reference unit, which represents an average unit in the fleet, has a 400 MW-gross nameplate capacity and a 10,000 Btu/kWh heat rate. Applying CCS to the reference unit with a 12-year amortization period and assuming a 50 percent annual capacity factor—a typical value for the fleet—results in annualized total costs that can be expressed as an abatement cost of \$14/ton of CO_2 reduced and an incremental cost of electricity of \$12/MWh. Included in these estimates is the EPA's assessment that the transport and storage costs are roughly \$30/ton, on average for the reference unit. For the fleet of coal-fired steam generating units with planned operation during or after 2030, and assuming a 12-year amortization period and 50 percent annual capacity factor and including source specific transport and storage costs, the average total costs of CCS are \$8/ton of CO_2 reduced and \$7/MWh. These total costs also account for the IRC section 45Q tax credit, a detailed discussion of which is provided in section VII.F.3.b.iii(B)(3) of this preamble. Compared to the representative costs of controls detailed in section VII.F.3.b.iii(B)(5) of this preamble (*i.e.,* emission control costs on EGUs of \$10.60 to \$29/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 costs for CCS on long-term coal-fired steam generating units are similar or better. Based on all of these analyses, the EPA is proposing that for the purposes of the BSER analysis, CCS is cost reasonable for long-term coal-fired steam generating units. The EPA also evaluated costs of CCS under

[534] 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*.

[535] 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*.

[536] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[537] Note that the determination that the BSER has been adequately demonstrated does not require that every source in the long-term coal-fired steam generating unit subcategory be within 100 km of CO_2 storage.

[538] 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*.

[539] The distance of 100 km is consistent with the assumptions underlying the NETL cost estimates for transporting CO_2 by pipeline.

[540] Note that the determination that the BSER has been adequately demonstrated does not require that every source in the long-term coal-fired steam generating unit subcategory be within 100 km of CO_2 storage.

various other assumptions of amortization period and annual capacity factor. Finally, it is noted that these CCS costs are lower than those in prior rulemakings due to the IRC section 45Q tax credit and reductions in the cost of the technology.

(A) CO_2 Capture Costs at Existing Coal-Fired Steam Generating Units

A variety of sources provide information for the cost of CCS systems, and they generally agree around a range of cost. The EPA has relied heavily on information recently developed by NETL, in the U.S. Department of Energy, in particular, ''Cost and Performance Baseline for Fossil Energy Plants,'' [541] and the ''Pulverized Coal Carbon Capture Retrofit Database.'' [542] In addition, the EPA developed an independent engineering cost assessment for CCS retrofits, with support from Sargent and Lundy.[543]

(B) CO_2 Transport and Sequestration Costs

As discussed in section VII.F.3.b.iii of this preamble, NETL's ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies'' is one of the more comprehensive sources of information on CO_2 transport and storage costs available. The Quality Guidelines provide an estimation of transport costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operations and maintenance costs.[544] These Quality Guidelines also provide an estimate of sequestration costs reflecting 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. NETL's Quality Guidelines model costs for a given cumulative storage potential.[545]

(C) Amortization Period and Annual Capacity Factor

In the EPA's cost analysis for long-term coal-fired steam generating units, the EPA assumes a 12-year amortization period and a 50 percent annual capacity factor. The 12-year amortization period is consistent with the period of time during which the IRC section 45Q tax credit can be claimed and the 50 percent annual capacity factor is consistent with the historical fleet average. However, increases in utilization are likely to occur for units that apply CCS due to the incentives provided by the IRC section 45Q tax credit. Therefore, the EPA also assessed the costs for CCS retrofitted to existing coal-fired steam generating units assuming a 70 percent annual capacity factor. For a 70 percent annual capacity factor and a 12-year amortization period, the costs for the reference unit are negative at −$8/ton of CO_2 reduced and −$7/MWh. The negative costs indicate that the value of the 45Q tax credit more than offsets the costs to install and operate CCS. For either capacity factor assumption, the $/MWh costs are comparable to or less than the costs for other controls ($10.60–$29.00/MWh) which are detailed in section VII.F.3.b.iii(B)(5) of this preamble.

As noted in section X.C.3 of this preamble, the EPA is also taking comment on the operating horizon that defines the threshold date between the definition of medium-term and long-term coal-fired steam generating units, specifically an operating horizon between 8 and 10 years (*i.e.,* January 1, 2038 to January 1, 2040), instead of the proposed 10-year operating horizon. For a 70 percent annual capacity factor and an 8-year amortization period, annualized costs of applying CCS for the reference unit are $24/ton of CO_2 reduced and $21/MWh, and it is possible that the cost of generation may be reasonable relative to the representative cost for wet FGD. However, CCS may be less cost favorable for units with shorter amortization periods. For a 70 percent annual capacity factor and a 7-year amortization period, costs for the reference unit are $39/ton of CO_2 reduced and $34/MWh. Additional details of the cost analysis are available in the *GHG Mitigation Measures for Steam Generating Units* TSD.

(D) 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 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 $74/MWh (2022$),[546] while the 2022 report estimated incremental levelized cost at $44/MWh (2022$).[547] 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 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 effectiveness of CCS for purposes of determining whether it qualifies as the BSER.

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

CCS for steam generating units is not expected to have unreasonable adverse consequences related to non-air quality health and environmental impacts or energy requirements. The EPA has considered non-GHG emissions impacts, the water use impacts, the transport and sequestration of captured CO_2, and energy requirements resulting from CCS. Because the non-air quality health and environmental impacts are closely related to the energy requirements, the latter are discussed first.

As noted in section VII.F.3.b.iii(C) of this preamble, stakeholders have shared with the EPA concerns about the safety of CCS projects and concerns that their communities may bear a

[541] *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf.*

[542] *https://netl.doe.gov/energy-analysis/details?id=69db8281-593f-4b2e-ac68-061b17574fb8.*

[543] Detailed cost information, assessment of technology options, and demonstration of cost reasonableness can be found in the *GHG Mitigation Measures for Steam Generating Units* TSD.

[544] 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.*

[545] Details on CO_2 transportation and sequestration costs can be found in the *GHG Mitigation Measures for Steam Generating Units* TSD.

[546] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 3 (July 2015). *https://www.netl.doe.gov/projects/files/CostandPerformanceBaselineforFossilEnergyPlantsVolume1aBitCoalPCandNaturalGastoElectRev3_070615.pdf.*

[547] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022). *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf.*

disproportionate environmental burden associated with CCS projects. The EPA is committed to working with its fellow agencies to foster meaningful engagement with communities and protect communities from pollution through the responsible deployment of CCS. 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. CCS projects undertaken pursuant to these emission guidelines will, if the EPA finalizes proposed revisions to the CAA section 111 implementing regulations,[548] be subject to requirements for meaningful engagement as part of the State plan development process. See section XII.F.1.b of this preamble for additional details.

(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. Amine-based CO_2 capture is an energy-intensive process. In particular, the solvent regeneration process requires substantial amounts of 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.[549] 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 *GHG Mitigation Measures for Steam Generating Units* TSD, available in the docket. Despite decreases in efficiency, IRC section 45Q tax credits provide an incentive for increased generation with full operation of CCS because the credits are proportional to the amount of captured and sequestered CO_2 emissions and not to the amount of electricity generated. The Agency is proposing that the energy penalty is relatively minor compared to the GHG benefits of CCS and, therefore, does not disqualify CCS as being considered the BSER for existing coal-fired steam generating units.

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. The EPA is proposing that designating CCS as the BSER for existing long-term coal-fired steam generating units would have limited and non-adverse impacts on the long-term structure of the power sector. Absent the requirements defined in this action, the EPA projects that 9 GW of coal-fired steam generating units would apply CCS by 2030 and 35 GW of coal-fired steam generating units, some without controls, would remain in operation in 2040. Designating CCS to be the BSER for existing long-term coal-fired steam generating units would likely result in more of the coal-fired steam generating unit capacity applying CCS. The time available before the compliance deadline of January 1, 2030, provides for adequate resource planning, including accounting for the downtime necessary to install the CO_2 capture equipment at long-term coal-fired steam generating units. While the IRC 45Q tax credit is available, long-term coal-fired steam generating units are anticipated to run at base load conditions. Total generation from coal-fired steam generating units in the other subcategories would gradually decrease over an extended period of time through 2039, subject to the commitments those units have chosen to adopt. Any decreases in the amount of generation from coal-fired steam generating units, whether locally or more broadly, are compensated for by increased generation from other sources. Additionally, for the long-term units applying CCS, the EPA is proposing the increase in the annualized cost of generation for those units is reasonable. Therefore, the EPA is proposing that there would be no unreasonable impacts on the reliability of electricity generation. A broader discussion of reliability impacts of the proposed actions is available in section XIV.F of this preamble. Finally, changes in the amount of generation from coal-fired steam generating units may contribute to additional generation from combined cycle combustion turbines. Since these EGUs have lower GHG and criteria pollutant emission rates than existing coal-fired steam generating units, overall emissions from the power sector would likely decrease.

(B) Non-GHG Emissions

For amine-based CO_2 capture retrofits to coal-fired steam generating units, decreased efficiency and increased utilization would otherwise result in increases of non-GHG emissions; however, importantly, most of those impacts would be 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. Decreases in efficiency result in increases in the relative amount of coal combusted per amount of electricity generated and would otherwise result in increases in the amount of non-GHG pollutants emitted per amount of electricity generated. Additionally, increased utilization would otherwise result in increases in total non-GHG emissions. However, substantial flue gas conditioning, particularly to remove SO_2, 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 column, if they do not already have one, and may need an additional polishing column (*i.e.,* quencher). A wet FGD column and a polishing column will also reduce the emission rate of particulate matter. Additional improvements in particulate matter removal may also be necessary to reduce the fouling of other components (*e.g.,* heat exchangers) of the capture process. NO_X emissions can cause solvent degradation and nitrosamine formation by chemical absorption of NO_X, depending on the chemical structure of the solvent. 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.[550]

[548] 87 FR 79176, 79190–92 (December 23, 2022).

[549] 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.*

[550] 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.*

A conventional multistage water or acid wash and 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.[551] [552] 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, and those units may not need to install SCR for process purposes. However, most existing coal-fired steam generating units either already have SCR or will be covered by proposed Federal Implementation Plan (FIP) requirements regulating interstate transport of NO_X (as an ozone precursors) from EGUs. See 87 FR 20036 (April 6, 2022). 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 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 minor NSR purposes that installation of SCR is not required for the units. See section XIII.A of this preamble for additional discussion of the NSR program.

(C) Water Use and Siting

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.[553] 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.[554] Regions with limited water supply may rely on dry or hybrid cooling systems, although, in areas with adequate water, wet cooling systems can be more effective.

With respect to siting considerations, CO_2 capture systems have a sizeable physical footprint and a consequent land-use requirement. The EPA is proposing that the water use and siting requirements are manageable and therefore the EPA does not expect any of these considerations to preclude coal-fired power plants generally from being able to install and operate CCS. However, the EPA is soliciting comment on these issues.

(D) Transport and Geologic Sequestration

As noted in section VII.F.3.b.iii 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 subpart RR requirements, ensure the protection of USDWs and the security of geologic sequestration.

iv. Extent of Reductions in CO_2 Emissions

CCS can be applied to coal-fired steam generating units at the source and reduce the CO_2 emission rate by 90 percent or more. Increased steam and power demand have a small impact on the reduction in emission rate 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.[555] After capture, CO_2 can be transported and securely sequestered.[556] 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. Technology Advancement

The EPA considered the potential impact of designating CCS as the BSER for long-term coal-fired steam generating units on technology advancement, and the EPA is proposing that designating CCS as the BSER will provide for meaningful advancement of CCS technology, for many of the same reasons as noted in section VII.F.3.b.iii(F) of this preamble.

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 16–23 percent capture, based on the type of coal combusted, and consequently, the EPA promulgated standards of performance of 1,400 lb CO2/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 was 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, and not 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 proposal, and, by the same token, the associated degree of emission limitation and resulting standards of performance necessarily differ as well.

b. Natural Gas Co-Firing

The EPA also evaluated natural gas co-firing at 40 percent of the heat input as the potential BSER for long-term coal-fired steam generating units. Because

[551] 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).

[552] 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).

[553] 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.*

[554] 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.*

[555] 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.*

[556] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

the EPA is proposing natural gas co-firing as the BSER for medium-term units, details that are common to medium-term and long-term units are discussed in section X.D.2.b of the preamble. Based on the discussion therein, the EPA is proposing that natural gas co-firing is adequately demonstrated and that the non-air quality health and environmental effects and energy requirements are not unreasonable. The costs of natural gas co-firing for a long-term unit may also be reasonable. For example, for a representative unit with a 10-year amortization period, the cost of reductions is $53/ton of CO_2. Finally, while 40 percent natural gas co-firing achieves unit-level emission rate reductions of 16 percent, those reductions are less than CCS with 90 percent capture. Therefore, because CCS achieves more reductions at the unit level and is proposed as cost reasonable for long-term units, the EPA is not proposing natural gas co-firing as the BSER for long-term coal-fired steam generating units.

c. Conclusion

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. 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 are outweighed by the benefits of the significant GHG emission reductions at reasonable cost. In contrast, co-firing 40 percent natural gas would achieve far fewer emission reductions without improving the cost effectiveness of the control strategy. These considerations provide the basis for proposing 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 this useful control technology. Although the EPA believes that long-lived coal-fired power plants will generally be able to implement and operate CCS within the cost parameters calculated as part of the BSER analysis, and therefore that they would be able to meet a standard of performance based on CCS with 90 percent capture, the EPA solicits comment on whether particular plants would be unable to do so, including details of the circumstances that might make retrofitting with CCS unreasonable or infeasible.

2. Medium-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA evaluates CCS and natural gas co-firing as potential BSER for medium-term coal-fired steam generating units.

In section X.D.1.a of this preamble, the EPA evaluated CCS with 90 percent capture of CO_2 as the BSER for long-term coal-fired steam generating units. Much of this evaluation is relevant for medium-term units. However, because they have shorter operating horizons and, as a result, a shorter period for amortization and for collecting the IRC section 45Q tax credits, CCS would be less cost effective for those units. Therefore, the EPA is not proposing CCS as BSER for medium-term coal-fired steam generating units.

Instead, the EPA is proposing 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 adverse non-air quality health and environmental impacts or energy requirements, and achieves meaningful reductions in CO_2 emissions. Co-firing also advances useful control technology and has acceptable national and long-term impacts on the energy sector, which provide additional, although not essential, support for treating it as the BSER.

a. CCS

In this section of the preamble, the EPA evaluates the use of CCS as the BSER for existing medium-term coal-fired steam generating units. This evaluation is much the same as the evaluation for long-term units, with the important difference of costs.

For long-term units, as discussed earlier in this preamble, the EPA's analysis used to evaluate the reasonableness of CCS costs employs a 12-year amortization period, which is consistent with the period of time during which the IRC section 45Q tax credit can be claimed. However, existing coal-fired steam generating units that have elected to commit to permanently cease operations prior to 2040—ones in the medium-term subcategory, as well as in the near-term, and imminent-term subcategories—would have a shorter period to amortize capital costs and also would not be able to fully utilize the IRC section 45Q tax credit. As a result, for these sources, the cost effectiveness of CCS is less favorable. As noted in section X.D.1.a.ii(C) of this preamble, for a 70 percent annual capacity factor and a 7-year amortization period, costs for the reference unit are $39/ton of CO_2 reduced and $34/MWh. This $/MWh generation cost is less favorable relative to the representative cost ($/MWh) for wet FGD, the costs for which are detailed in section VII.F.3.b.iii(B)(5). Due to the higher incremental cost of generation, the EPA is not proposing CCS as the BSER for medium-term coal-fired steam generating units.

While the EPA is not proposing CCS as BSER for the proposed subcategory of medium-term units, the EPA is taking comment on the operating horizon (*i.e.,* between 8 and 10 years, instead of the proposed 10-year operating horizon) that most appropriately defines the threshold date between medium-term and long-term units and the EPA is also taking comment on the level of costs of CCS that should be considered reasonable.

b. Natural Gas Co-Firing

In this section of the preamble, the EPA evaluates natural gas co-firing as potential BSER for medium-term coal-fired steam generating units. Considerations that are common to the proposed subcategories of existing coal-fired steam generating units are discussed in section X.D.1.a of the preamble, in addition to considerations that are specific to medium-term 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 proposing 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 proposing to find 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

Most 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.[557] 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 proposing 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 *GHG Mitigation Measures for Steam Generating Units* TSD.

(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 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, many will 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. As discussed in the *GHG Mitigation Measures for Steam Generating Units* TSD, 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. 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 proposed rule.

The maximum amount of pipeline capacity, if all coal-fired steam capacity in the medium-term subcategory implemented the proposed BSER by co-firing 40 percent natural gas, would be a fraction of the pipeline capacity constructed recently. The EPA estimates that this maximum total capacity would be about 17.3 billion cubic feet per day, which would require almost 4,000 miles of pipeline costing roughly $13.3 billion. Over 5 years, this maximum total incremental pipeline capacity would amount to 800 miles per year and approximately $2.7 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 capacity of 10 to 25 billion cubic feet per day. This represents an estimated annual investment of up to nearly $15 billion. These historical annual values are much higher than the maximum annual values that could be expected under this proposed BSER measure—which, as noted above, represent a conservative estimate that overstates the amount of co-firing that the EPA projects would occur under this proposed 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 average about $37 billion per year through 2035, which is lower than historical levels. Approximately $10 to $20 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 considerably greater than the average annual expenditure of $2.7 billion on 800 miles per year of new pipeline construction that would be necessary for the entire operational fleet of coal-fired steam generating units to co-fire with natural gas. The actual pipeline investment for this subcategory would be substantially lower.

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

[557] 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*.

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 post-IRA 2022 reference case projects that in 2030, the average delivered price of coal will be $1.47/MMBtu and the average delivered price of natural gas will be $2.53/MMBtu. Thus, assuming the same level of generation and no impact on heat rate, the additional fuel cost would be above $1/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 *GHG Mitigation Measures for Steam Generating Units* TSD, the EPA's cost estimates assume a 1 percent 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. For purposes of the cost reasonableness estimates as follows, the EPA assumes pipeline costs of $92/kW, which is the median value of all unit-level pipeline cost estimates, as explained in the *GHG Mitigation Measures for Steam Generating Units* TSD. The range in costs reflects a range in the amortization period of the capital costs over 6 to 10 years, which is consistent with the amount of time over which the units in the medium-term subcategory could be operational.

The EPA sums the natural gas co-firing costs as follows: For a typical base load coal-fired steam generating unit in 2030, the EPA estimates that the cost of co-firing with 40 percent natural gas on an annual average basis is approximately $53 to $66/ton CO_2 reduced, or $9 to $12/MWh, respective to amortization periods of 10 to 6 years. This estimate is based on the characteristics of a typical coal-fired unit in 2021 (400 MW capacity and an average heat rate of 10,500 Btu/kWh) operating at a typical capacity factor of about 50 percent, and it assumes a pipeline cost of $92/kW, as discussed earlier in this preamble.

Based on the coal-fired steam generating units that existed in 2021 and that do not have known plans to cease operations or convert to gas by 2030, and assuming that each of those units continues to operate at the same level in 2030 as it operated in 2017–2021, on average, the EPA estimates that the weighted average cost of co-firing with 40 percent natural gas on an annual average basis is approximately $64 to $78/ton CO_2 reduced, or $11 to $14/MWh. The $/ton cost estimate is lower than average for approximately 82 GW, and the $/MWh cost estimate is lower than average for 86 GW (about 69 percent and 72 percent, respectively, of the relevant coal fleet). These estimates and all underlying assumptions are explained in detail in the *GHG Mitigation Measures for Steam Generating Units* TSD.

As was described in section X.D.1 of this preamble, the EPA has compared the estimated costs discussed in section X.D.2 of this preamble to costs that coal-fired steam generating units have incurred to install controls that reduce other air pollutants, such as SO_2. Compared to the representative costs of controls detailed in section VII.F.3.b.iii(B)(5) of this preamble (*i.e.,* emission control costs on EGUs of $10.60 to $29/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)), both estimates of annualized costs of natural gas co-firing (approximately $53–$66/ton or $9–$12/MWh for a typical unit and $64–$78/ton or $11–$14/MWh on average)) are comparable or lower. The range of cost effectiveness estimates presented in this section is lower than previously estimated by the EPA in the proposed CPP, for several reasons. Since then, the expected difference between coal and gas prices has decreased significantly, from over $3/MMBtu to about $1/MMBtu in this proposal. Additionally, 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.

Based on the cost analysis presented in this section, the EPA is proposing that the costs of natural gas co-firing are reasonable for the medium-term coal-fired steam generating unit subcategory.

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 proposal, 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.

Additionally, sufficient regulations 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.[558] PHMSA also recently promulgated a rule covering natural gas transmission,[559] 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.[560] Additionally, FERC oversees the development of new natural gas pipelines.

(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 32520 at 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. Additionally, the natural gas co-firing measure is now being proposed for a medium-term coal-fired steam generating unit subcategory, a group of units that will operate at most for 10 years following the compliance date, which would further reduce the total amount of required natural gas.

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 proposing 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 proposing 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 shifting 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 proposed 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. Conclusion

The EPA proposes 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, any adverse non-air quality health and environmental impacts and energy requirements of natural gas co-firing are limited and are outweighed by the benefits of the emission reductions at reasonable cost. In contrast, CCS, although achieving greater emission reductions, would be less cost-effective, in general, for the proposed subcategory of medium-term units.

While the EPA is not proposing CCS as BSER for the proposed subcategory definition of medium-term units, the EPA is taking comment on the operating horizons that define the threshold date between medium-term and long-term units (*i.e.,* between 8 and 10 years, instead of the proposed 10-year operating horizon) and on what amount of costs should be considered reasonable.

[558] 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).

[559] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (84 FR 52180; October 1, 2019).

[560] 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).

3. Imminent-Term and Near-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA evaluates CCS, natural gas co-firing, low levels of natural gas co-firing, and routine methods of operation and maintenance as the BSER for imminent-term and near-term coal-fired steam generating units. Primarily because of the effect of a short operating horizon on the cost of controls for these units, the EPA proposes routine methods of operation and maintenance as the BSER.

a. CCS

As noted in section X.D.2.a of this preamble, the EPA is not proposing CCS for medium-term units due to $/MWh costs being less favorable based on the appropriate cost metrics. Because of the shorter operating horizons for imminent-term and near-term coal-fired steam generating units, CCS is less cost favorable for them than for medium-term units. Therefore, the EPA is not proposing CCS as BSER for imminent-term or near-term coal-fired steam generating units. Additional details of cost values for amortization periods representative of imminent-term and near-term units are available in the *GHG Mitigation Measures for Steam Generating Units* TSD.

b. Natural Gas Co-Firing

i. Natural Gas Co-Firing at 40 Percent

Much of the discussion of natural gas co-firing in section X.D.2.b of this preamble for medium-term units is relevant for imminent-term and near-term units, except that natural gas co-firing is less cost effective for the latter units because of their short operating horizons, particularly on a $/ton of CO_2 reduced basis. For a 2-year amortization period, annualized costs for the representative unit are $130/ton of CO_2 reduced and $23/MWh of generation. Therefore, the EPA is not proposing natural gas co-firing as BSER for imminent-term or near-term units. Additional details of cost are available in the *GHG Mitigation Measures for Steam Generating Units* TSD.

ii. Natural Gas Co-Firing at Low Levels of Heat Input

Although higher levels of natural gas co-firing may be less cost effective for imminent-term and near-term units, it is possible that lower levels of natural gas co-firing may be cost reasonable. Many units have demonstrated the ability to co-fire with natural gas over short periods of time and operating with those same levels of natural gas co-firing over longer periods of time (*i.e.,* annually) may achieve emission reductions. A low level of natural gas co-firing (up to 10 percent of annual heat input) is adequately demonstrated and may be broadly achievable, may achieve reductions in GHG emissions, may be of reasonable cost, and is unlikely to cause unreasonable adverse non-air quality health and environmental impacts or result in substantial energy requirements. Therefore, the EPA is soliciting comment on low levels of natural gas co-firing as a potential component of the BSER for imminent-term and near-term coal-fired steam generating units.

The EPA recognizes that different coal-fired units may be already capable of different natural gas co-firing rates (as discussed in section X.D.2.b.i of this preamble) and is therefore soliciting comment on defining a potential BSER on the basis of the maximum hourly heat input of natural gas fired in the unit (MMBtu/hr) relative to the maximum hourly heat input the unit is capable of (*i.e.,* the nameplate capacity on an MMBtu/hr basis). Alternatively, the EPA is soliciting comment on a fixed value of annual heat input percentage that represents a low level of natural gas co-firing, as well as the definition of a low level of natural gas co-firing that is based on the characteristics of an existing facility (*e.g.,* the capacity of the existing pipeline). The EPA is also soliciting comment on a degree of emission limitation resulting from low levels of natural gas co-firing, as detailed in section X.D.4.c of this preamble.

(1) Adequately Demonstrated

For many of the same reasons stated in section X.D.2.b.i of this preamble for natural gas co-firing at higher levels, natural gas co-firing at low levels is adequately demonstrated. The EPA also identified that 369 of the 565 EGUs operating at the end of 2021 have either reported natural gas as a fuel source, are located at a plant with a natural gas generator, and/or are located at a plant with a natural gas pipeline connection. A large percentage of the existing fleet of coal-fired steam generating units would therefore likely be able to co-fire natural gas at low levels without having to make boiler modifications or build additional pipelines.

(2) Costs

The costs of low levels of natural gas co-firing may be reasonable because low levels of natural gas co-firing likely require little, if any, capital investment. Additionally, the relatively small increase in natural gas fuel use would only result in a modest increase in total fuel cost.

(3) Non-Air Quality Health and Environmental Impact and Energy Requirements

For many of the same reasons stated in section X.D.2.b.iii of this preamble, low levels of natural gas co-firing are unlikely to cause unreasonable adverse non-air quality health and environmental impacts or result in substantial energy requirements. Furthermore, low levels of natural gas co-firing may require only limited construction of additional infrastructure as existing pipeline laterals to the units should be of sufficient size to achieve low levels of natural gas co-firing.

(4) Extent of Reductions in CO_2 Emissions

The emission reductions achieved at the unit from low levels of natural gas co-firing of 1 to 10 percent may be relatively low at around 0.4 to 4 percent, respectively. However, these are likely on average greater than the emission reductions that could be achievable by other technologies, such as HRI. Furthermore, because the efficiency of the unit is not increased as with HRI, the unit likely does not move up in dispatch order, and it is likely the unit would not be subject to the rebound effect. See section X.D.5 of this preamble for a discussion of HRI.

(5) Technology Advancement

Low levels of natural gas co-firing do not advance useful control technology, for reasons similar to those discussed in section X.D.2.b.v of this preamble.

c. Routine Methods of Operation and Maintenance

For the imminent-term and near-term coal-fired steam generating units, the EPA is proposing that the BSER is routine methods of operation and maintenance already occurring at the unit, so as to maintain the current unit-specific CO_2 emission rates (expressed as lb CO_2/MWh).

Routine methods of operation and maintenance are adequately demonstrated because units already operate by those methods. They will not result in additional costs from any controls, and will not create adverse non-air quality health and environmental impacts or energy requirements. They will not achieve CO_2 emission reductions at the unit level relative to current performance, but they can prevent worsening of emission rates over time. Although they do not advance useful control technology, they do not have adverse impacts on the energy sector from a nationwide or long-term perspective.

4. Degree of Emission Limitation

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. Proposed presumptive standards of performance are detailed in section XII.D 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, for each of the four subcategories of coal-fired steam generating units, the EPA is proposing to determine the degree 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 proposing 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 proposing 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).

As noted in section X.D.1.a of this preamble, new CO_2 capture retrofits on existing coal-fired steam generating units may achieve capture rates greater than 90 percent, and the EPA is taking comment on a range of capture rates that may be achievable. As noted in section VII.F.3.b.iii(A)(2) of this preamble, the operating availability (*i.e.,* the amount of time a process operates relative to the amount of time it planned to operate) of industrial processes is usually less than 100 percent. Assuming that CO_2 capture achieves 90 percent capture when available to operate, that CCS is available to operate 90 percent of the time the coal-fired steam generating unit is operating, and that the steam generating unit operates the same whether or not CCS is available to operate, total emission reductions would be 81 percent. Higher levels of emission reduction could occur for higher capture rates coupled with higher levels of operating availability relative to operation of the steam generating unit. If the steam generating unit were not permitted to operate when CCS was unavailable, there may be local reliability consequences, and the EPA is soliciting comment on how to balance these issues. Additionally, the EPA is soliciting comment on a range of the degree of emission limitation achievable, in the form of a reduction in emission rate of 75 to 90 percent when determined 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).

c. Imminent-Term and Near-Term Coal-Fired Steam Generating Units

As discussed above, the BSER for imminent-term and near-term coal-fired steam generating units is routine methods of operation and maintenance. Application of this BSER results in no increase in emission rate. Thus, the degree of emission limitation corresponding to the application of the BSER is no increase in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.,* an annual calendar-year basis).

Because the EPA is soliciting comment on low levels of natural gas co-firing as a potential BSER for imminent-term and near-term units, the EPA is also soliciting comment on the degree of emission limitation that may be achievable by application of low levels of natural gas co-firing. The EPA is soliciting comment on degrees of emission limitation defined by reductions in emission rate on a lb CO_2/MWh-gross basis that are equal to the percent of heat input times 0.4, the percent of reduction in emission rate that may be achieved for each percent of natural gas heat input. For example, for natural gas co-firing at 1 to 10 percent, this results in a degree of emission limitation of 0.4 to 4 percent reduction in emission rate on a lb CO_2/MWh-gross basis (over an extended period of time). More specifically, the EPA solicits comment on the degree of emission limitation based on the calculation method defined in the preceding text up to a 4 percent reduction in emission rate (lb CO_2/MWh-gross) over an extended period of time. Alternatively, as the EPA is also soliciting comment on a fixed percent of low levels of natural gas co-firing, the EPA is additionally soliciting comment on a fixed degree of emission limitation based on the same calculation method. Because the reductions in GHG emissions from low levels of natural gas co-firing are relatively low and may be challenging to measure, the EPA is also soliciting comment on a degree of emission limitation defined on a percent of heat input basis, although the EPA also recognizes that measurement of fuel flow may also have challenges.

5. Other Emission Reduction Measures

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 one 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 proposing 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'').

A description of the ACE Rule is detailed in section IX of this preamble.

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 *GHG Mitigation Measures for Steam Generating Units* TSD 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. In this action, where different subcategories of units are proposed 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 relatively minor overall GHG emission reductions that would be expected from this measure, the EPA is not proposing HRI as the BSER for any subcategory of existing coal-fired steam generating units.

E. Natural Gas-Fired and Oil-Fired Steam Generating Units

In this section of the preamble, the EPA is addressing natural gas- and oil-fired steam generating units. The EPA is proposing the BSER and degree of emission limitation achievable by application of the BSER for those units and identifying the associated emission rates that States may apply to these units. For the reasons described here, the EPA is proposing subcategories based on load level (*i.e.,* annual capacity factor), specifically, units that are base load, intermediate load, and low load. At this time, the EPA is not proposing requirements for low load units but is taking comment on a BSER of lower emitting fuels for those units. The EPA is proposing 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 proposing presumptive standards of performance that differ between intermediate and base load units due to their differences in operation, as detailed in section XII.D.1.b.v of this preamble. The EPA is also proposing a separate subcategory for non-continental oil-fired steam generating units, which operate differently from continental units, with presumptive standards of performance detailed in section XII.D.1.b.vi of this preamble.

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 CAMD 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 *Natural Gas- and Oil-fired Steam Generating Unit* TSD. 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 efficient and CO_2 emission rates are lower. Based on these performance differences between these load levels, the EPA is, in general, proposing to divide natural gas- and oil-fired steam generating units into three subcategories each—low load, intermediate load, and base load—as specified in section X.C.2 of this preamble: ''low'' load is defined by annual capacity factors less than 8 percent, ''intermediate'' load is defined by annual capacity factors greater than or equal to 8 percent and less than 45 percent, and ''base'' load is defined by annual capacity factors greater than 45 percent.

1. 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 would 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 proposing CCS as the BSER for them.

The EPA has reviewed other possible controls but is not proposing any of them as the BSER for natural gas- and oil-fired units either. Co-firing hydrogen in a boiler is technically possible, but, for the same reasons discussed in section VII of this preamble, the only hydrogen that could be considered for the BSER would be low-GHG hydrogen, and there is limited availability of that hydrogen now and in the near future. Additionally, for natural gas-fired steam generating units, setting a future standard based on hydrogen would 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. 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 proposing 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 proposing 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 initial modeling, which supports this proposed rule, indicates that by 2040, a number of natural gas-fired steam generating units 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 the BSER should preclude 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.

The EPA is also taking comment on, but not proposing, a BSER of lower emitting 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 proposing lower emitting fuels as BSER for new low load combustion turbines as described in section VII 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 XII.D of this preamble, may be reasonable. The EPA is soliciting comment on the fuel types that would constitute ''uniform fuels'' specific to low load natural gas- and oil-fired steam generating units.

2. Degree of Emission Limitation

As discussed above, because the proposed BSER for base load and intermediate load natural gas- and oil-fired steam generating plants 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.,* an annual calendar year).

F. Summary

The EPA has evaluated options for BSER for GHG emissions for fossil fuel-fired steam generating units. The EPA is proposing subcategorization of steam generating units by the type of fossil fuel fired in the unit, and, for each fuel type, further levels of subcategorization. For each subcategory, the EPA is proposing a BSER and resulting degree of emission limitation achievable by application of that BSER, as summarized in table 5, with presumptively approvable standards of performance for use in State plan development (see section XII of this preamble for details) included for completeness. For coal-fired steam generating units that plan to operate in the long-term, the EPA is proposing a BSER of CCS with 90 percent capture of CO_2. In response to industry stakeholder input and recognizing that the cost effectiveness of controls depends on a unit's expected operating time horizon, which dictates the amortization period for the capital costs of the controls, the EPA is proposing other BSER for coal-fired units with shorter operating horizons while taking comment on what dates most appropriately define the thresholds between these different subcategories. For the different subcategories of natural gas- and oil-fired units, the EPA is proposing BSERs based on routine methods of operation and maintenance. The EPA solicits comment on the proposed BSER and degrees of emission limitation, as well as the proposed subcategorization, including the potential to remove the imminent-term subcategory and include units with earlier commitments to permanently cease operations in either the near-term or medium-term subcategory. It is noted that for imminent-term and near-term coal-fired steam generating units, the EPA is also soliciting comment on potential BSERs based on co-firing low levels of natural gas.

TABLE 5—SUMMARY OF PROPOSED BSER, SUBCATEGORIES, AND DEGREES OF EMISSION LIMITATION FOR AFFECTED EGUS

Affected EGUs	Subcategory definition	BSER	Degree of emission limitation	Presumptively approvable standard of performance [561]	Ranges in values on which the EPA is soliciting comment
Long-term existing coal-fired steam generating units.	Coal-fired steam generating units that have not elected to commit to permanently cease operations by January 1, 2040.	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.	The achievable capture rate from 90 to 95 percent or greater and the achievable degree of emission limitation defined by a reduction in emission rate from 75 to 90 percent.
Medium-term existing coal-fired steam generating units.	Coal-fired steam generating units that have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2040, and that are not near-term units.	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.	The percent of natural gas co-firing from 30 to 50 percent and the degree of emission limitation from 12 to 20 percent.
Near-term existing coal-fired steam generating units.	Coal-fired steam generating units that have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2035, and commit to adopt an annual capacity factor limit of 20 percent.	Routine methods of operation.	No increase in emission rate (lb CO_2/MWh-gross).	An emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline.	The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific baseline.
Imminent-term existing coal-fired steam generating units.	Coal-fired steam generating units that have elected to commit to permanently cease operations before January 1, 2032.	Routine methods of operation.	No increase in emission rate (lb CO_2/MWh-gross).	An emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline.	The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific baseline.

[561] Presumptive standards of performance are discussed in detail in section XII 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.

TABLE 5—SUMMARY OF PROPOSED 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 [561]	Ranges in values on which the EPA is soliciting comment
Base load continental 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 1,300 lb CO_2/MWh-gross.	The threshold between intermediate and base load from 40 to 50 percent annual capacity factor; the degree of emission limitation from 1,250 lb CO_2/MWh-gross to 1,800 lb CO_2/MWh-gross.
Intermediate load continental 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 1,500 lb CO_2/MWh-gross.	The degree of emission limitation from 1,400 lb CO_2/MWh-gross to 2,000 lb CO_2/MWh-gross.
Low load (continental and non-continental) existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor less than 8 percent.	None proposed			The threshold between low and intermediate load from 5 to 20 percent annual capacity factor.
Intermediate and base load non-continental existing oil-fired steam generating units.	Non-continental oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline.	The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific baseline.
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 1,300 lb CO_2/MWh-gross.	The threshold between intermediate and base load from 40 to 50 percent annual capacity factor; The acceptable standard from 1,250 lb CO_2/MWh-gross to 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 1,500 lb CO_2/MWh-gross.	The acceptable standard from 1,400 lb CO_2/MWh-gross to 1,600 lb CO_2/MWh-gross.
Low load existing natural gas-fired steam generating units.	Natural gas-fired steam generating units with an annual capacity factor less than 8 percent.	None proposed			The threshold between low and intermediate load from 5 to 20 percent annual capacity factor.

XI. Proposed Regulatory Approach for Emission Guidelines for Existing Fossil Fuel-fired Stationary Combustion Turbines

A. Overview

Because the EPA has established NSPS for GHG emissions from new fossil fuel-fired stationary combustion turbines under CAA section 111(b), it has an obligation to also establish emission guidelines for GHG emissions from existing fossil-fuel fired stationary combustion turbines under CAA section 111(d). Existing fossil fuel-fired stationary combustion turbines already represent a significant share of GHG emissions from EGUs and are quickly becoming the largest source of GHG emissions from the power sector. As other fossil fuel-fired EGUs reduce utilization or retire, at least some of this generation may shift to the existing combustion turbine fleet with significant GHG emission implications, particularly if the latter is not subject to limits on GHG emissions. For these reasons, the EPA intends to discharge its obligation to prescribe emission guidelines for these sources as expeditiously as practicable. In this document, the EPA is proposing emission guidelines for certain existing fossil fuel-fired stationary combustion turbines and soliciting comment on approaches that could be used to establish emission guidelines for the remaining units in the fleet.

In considering how to address this problem, the EPA believes there are at least two key factors to consider. The first is that determining the BSER and issuing emission guidelines covering these units sooner rather than later is important to address the GHG emissions from this growing portion of the inventory. The second is related to the size of the affected fleet and the implications for the feasibility and timing of implementing potential candidates for BSER. As discussed later in this section, there are at least three technologies that could be applied to reduce GHGs from existing combustion turbines (CCS, hydrogen co-firing, and heat rate improvements), all of which are available today and are being pursued to at least some degree by owners and operators of these sources. Although the EPA believes that these technologies are available and adequately demonstrated at the level of individual existing combustion turbines, emission guidelines for these sources must also consider how much of the fleet could reasonably implement one or more of these potential BSER approaches in a given time frame.

Furthermore, the EPA is aware that grid operators and power companies currently rely on existing fossil fuel-fired combustion turbines as a flexible and readily dispatchable resource that plays a key role in fulfilling resource adequacy and operational reliability needs. Although advancements in energy storage and accelerated development and deployment of zero-emitting resources may diminish reliance on existing fossil fuel-fired combustion turbines for reliability purposes over time, it is imperative that emission guidelines for these sources not impair the reliability of the bulk power system. For these reasons, the EPA believes that it is important that a BSER determination and associated emission guidelines for existing fossil fuel-fired combustion turbines rely on GHG control options that can be feasibly and cost-effectively implemented at a scale commensurate with the size of the regulated fleet, and provide sufficient operational flexibility and lead time to allow for smooth implementation of the GHG emission limitations that preserves system reliability.

Given the large size of the existing combustion turbine fleet and the lead time required to develop CCS and hydrogen-related infrastructure, the EPA believes the BSER for this category entails significant lead time for application of CCS or low-GHG hydrogen co-firing. As a result, the EPA is planning to break the existing combustion turbine category into two segments, and is focusing this proposal on the largest and most frequently operated (*e.g.,* base load) existing combustion turbines that have the highest GHG emissions on an annual basis. For these large and frequently operated existing combustion turbines, the EPA is proposing to determine that the BSER consists of either application of CCS by 2035, or application of low-GHG hydrogen co-firing beginning in 2032, based on an evaluation of the statutory BSER criteria that mirrors EPA's evaluation of the BSER for new base load combustion turbines. This focused approach will limit GHG emissions from the highest-emitting existing natural gas combustion turbines, while allowing sufficient lead time for application of CCS or low-GHG hydrogen co-firing and limiting the amount of affected capacity to a degree that is consistent with the availability of these two GHG mitigation technologies. The EPA intends to undertake a separate rulemaking as expeditiously as practicable that addresses emissions from the remaining combustion turbines.

In this document, the EPA is soliciting comment on both the scope of these proposed emission guidelines (in other words, the applicability thresholds that would determine which existing combustion turbines are in the first segment) as well as the BSER for units covered in this rulemaking. In section XII of this preamble, the EPA is also taking comment on the associated State plan requirements associated with the BSER for existing fossil fuel-fired turbines.

As described in more detail below, the EPA is proposing to determine that the BSER for large and frequently operated existing stationary combustion turbines is the same as for the proposed second phase of requirements for new base load combustion turbines. Accordingly, the EPA is proposing emission guidelines for these existing stationary combustion turbines that would require either that these sources achieve a degree of emission limitation consistent with the use of CCS by 2035, or achieve a degree of emission limitation reflecting the utilization of 30 percent low-GHG hydrogen by volume by 2032 (increasing to 96 percent low-GHG hydrogen by volume by 2038).

The EPA believes that it is important to stagger CCS requirements for existing coal-fired units and new and existing fossil fuel-fired turbines to allow time for both deployment of CCS infrastructure and to accommodate increased demand for specialized engineering and construction labor needed to build CCS equipment. The EPA also believes that because coal-fired units emit more CO_2/MWh, that to the extent that there are limitations to the amount of CCS that can be installed by 2030 it makes sense to focus a CCS BSER on those coal-fired units first. A 2035 compliance timeframe would allow for staggering of resources needed to install CCS while still allowing existing turbines to take advantage of the IRC section 45Q tax credits to make CCS controls more cost-effective or to use hydrogen, produced at facilities eligible for the 45V tax credits, making hydrogen co-firing more cost effective.[562] In the rest of this section, the EPA proposes regulations for the first segment and solicits comment on specific elements of the approach. This section also briefly discusses what BSER might look like for units in the second rulemaking, and requests comments that could inform the development of a rulemaking defining BSER, degrees of emission limitation, compliance deadlines and other elements of an emission guideline for those units at a later date.

As explained in more detail later in this section, the EPA is proposing that the first segment it would cover would be units greater than 300 MW with an annual capacity factor of greater than 50 percent. The EPA projects that 37 GW of capacity would meet these criteria in 2035, representing 14 percent of the projected existing combustion turbine capacity and 23 percent of the projected generation from existing combustion turbines in 2035. As is explained further below, the EPA is proposing this capacity factor and capacity threshold after weighing the quantity of emissions from these units and considerations about the feasibility of installing significant amounts of CCS and/or hydrogen co-firing. In short, these units offer the best opportunity to achieve significant emissions reduction consistent with what the EPA believes these technologies will be capable of on a national scale. Similar to its proposal for new base load turbines, the EPA is proposing that BSER for those existing sources be both pathways, that is CCS with 90 percent capture in 2035 and clean hydrogen combusting 30 percent by volume in 2032 and 96 percent by volume in 2038. Alternatively, as with the proposal for new base load turbines, the EPA is taking comment on whether to finalize a BSER with a single pathway based on application of CCS with 90 percent capture, which could also be met by co-firing with low-GHG hydrogen as a compliance option, or vice-versa. The EPA is also taking comment on whether the compliance date should begin earlier, including as early as 2030.[563]

The EPA has promulgated several prior rulemakings under both CAA section 111(b) and section 111(d) that provide the regulated sector with lead time to accommodate the time needed to deploy control technology. Section VII.F.3.a of this preamble discusses, in the section 111(b) context, precedent for rulemakings that provide such lead time. For additional examples under CAA section 111(d), see 70 FR 28606, 28619 (May 18, 2005) (establishing emission guidelines for electric utility steam generating units, with a 13-year compliance timeframe for a second control phase); 61 FR 9905, 9919 (March 12, 1996) (establishing emission guidelines for municipal solid waste landfills, with a 2.5-year compliance

[562] CCS projects that commence construction as late as December 31, 2032 can qualify for the 45Q tax credit.

[563] If we finalize one of these variations, the state plan requirements may change accordingly.

timeframe); 62 FR 48348, 48381 (September 15, 1997) (establishing emission guidelines for hospital/medical/infectious waste incinerators, with up to 3 years after State plan approval for facilities to install control equipment). Section XI.B provides background information concerning the composition of the current fossil fuel-fired stationary combustion turbine fleet and how it is expected to change in the near future. In section XI.C, the EPA proposes an approach for units covered in this rulemaking and in section XI.D, the EPA summarizes the key topics for which we are soliciting comment relative to existing combustion turbines. Finally, section XI.E, outlines a potential approach for units covered in a second rulemaking

B. The Existing Stationary Combustion Turbine Fleet

In 2021, existing combustion turbines represented 37 percent of the GHG emissions from the power sector and 40 percent of the generation from the power sector. In the EPA's updated baseline projections for the power sector, they represent 74 percent of the GHG emissions and 25 percent of the generation in 2035. In EPA's modeling of the 2035 control case, in which both existing fossil fuel-fired EGUs and new stationary combustion turbine EGUs are subject to the emissions limitations proposed in this action but existing combustion turbine EGUs are left uncontrolled, load shifting from those two categories of sources to the existing combustion turbines results in an increase in the share of the emissions from existing combustion turbines (including combined cycle and simple cycle combustion turbines) to 82 percent while their share of generation remains 25 percent. Moreover, in that control case, existing combined cycle combustion turbines are responsible for 71 percent of the CO_2 emissions from the power sector.

In the EPA's modeling in support of these rules, we see two trends that are important relative to existing combustion turbines. First, the EPA's analysis of the reference case (which includes the impacts of IRA without considering the GHG limitation requirements proposed in these rules) projects a long-term decline in generation and emissions from existing combustion turbines relative to current generation and emissions. In this reference case, combined cycle generation falls in each model run year from 2028 through 2050, and it falls by more than 50 percent between 2030 and 2045. Generation from existing simple cycle combustion turbines is projected to peak in 2030 before declining by more than 70 percent by 2045. While generation falls from turbines, this is primarily caused by declining capacity factors, not through retirements.

Historical data shows a wide range of variation in both the heat rate and the GHG emission rates among both existing combined cycle combustion turbines and existing simple cycle combustion turbines. The GHG emission rates for existing combined cycle units range from as low as 644 lb CO_2/MWh-gross to as high as 1,891 lb CO_2/MWh-gross, and annual capacity factors range from as low as 1 percent to as high as 85 percent. While there is some correlation between units with low-GHG emission rates (*e.g.,* more efficient units) and utilization, some low efficiency combined cycle units have historically operated at very high capacity factors. For instance, two of the highest operating units (at 85 percent capacity utilization) have GHG emission rates of nearly 1,200 lb/MWh-gross.

C. BSER for Base Load Turbines Over 300 MW

As noted earlier, the EPA is adopting an approach in which existing combustion turbines would be regulated in two segments. The proposed emission guidelines presented in this document focus on the first segment, which comprises the base load units (*e.g.,* those operated at capacity factors of greater than 50 percent) over 300 MW. The EPA intends to undertake a separate rulemaking to address the second segment, comprising the remainder of the existing fossil fuel-fired stationary combustion fleet, as expeditiously as practicable.

Because the first segment would be focused on the largest most frequently used units, the EPA is proposing that the BSER for these units would be CCS or a BSER based upon burning low-GHG hydrogen. As is the case for new base load combustion turbines, each of these sets of controls is adequately demonstrated, of reasonable cost, and consistent with the other criteria to qualify as the BSER.

Because the second segment would include both smaller more frequently used units and less frequently used units, in that action, the EPA anticipates considering a broader range of technologies including heat rate improvements. This approach recognizes the imperatives (the urgent need to reduce greenhouse gases), the opportunities (including the availability of IRC section 45Q tax credits incentivizing CCS installation as long as sources commence construction by January 1, 2033), and the need for infrastructure for CCS and co-firing low-GHG hydrogen to be deployed at a broader scale if these BSER technologies are to be deployed broadly at smaller and less frequently operated existing combustion turbines.

The EPA is proposing emission guidelines for units with a capacity factor greater than 50 percent and a capacity of greater than 300 MW, but is also taking comment on whether that capacity factor threshold or capacity threshold should be lower (for instance 40 percent for the capacity factor and 200 MW or 100 MW for the capacity). The EPA is proposing that 300 MW is the appropriate threshold for applicability because it focuses on the units with the highest emissions where CCS is likely to be most cost effective. As an important first step towards abating emissions from the existing turbine fleet and recognizing that at least some project developers are considering the use of clean hydrogen in base load turbines [564] and recognizing that there are likely limits to the clean hydrogen supply in the mid-term, the EPA believes that it is appropriate to also propose a clean hydrogen BSER for the same set of units. Table 6 provides information from IPM detailing the amount of capacity and generation from the 2035 IPM projected control case that would be covered under various capacity thresholds.

[564] As one developer notes, ''the plant will be capable of supporting a balanced and diverse power generation portfolio in the future; from energy storage capable of accommodating seasonal fluctuations from renewable energy, to cost effective, dispatchable intermediate and baseload power.'' *https://www.longridgeenergy.com/news/2020-10-13-long-ridge-energy-terminal-partners-with-new-fortress-energy-and-ge-to-transition-power-plant-to-zero-carbon-hydrogen.*

TABLE 6—KEY CHARACTERISTICS FOR BASELOAD COMBINED CYCLE UNITS OF VARIOUS CAPACITIES

NGCC units projected to run at a capacity factor of greater than 50 percent and at a capacity size greater than	Capacity (GW)	Percentage of total NGCC capacity (%)	Percentage of total NGCC generation (%)
100 MW	134	49	78
200 MW	85	31	51
300 MW	37	14	23
400 MW	12	4	10
500 MW	6	2	7

The EPA believes this approach would ensure that GHG emissions limitations are implemented first at the subset of existing fossil fuel-fired combustion turbines that contributes the most to GHG emissions, and where the benefits of implementing GHG controls would be greatest.

The EPA believes there are three sets of controls that could potentially qualify as the BSER for the group of large and frequently-operated combustion turbines covered in the first rulemaking. Those controls are heat rate/efficiency improvements, co-firing low-GHG hydrogen, and use of CCS. We discuss each of these below, and in the course of each discussion explain why we are proposing that the following controls qualify as the BSER: co-firing with low-GHG hydrogen in the amounts of 30 percent (by volume) by 2032 and 96 percent (by volume) by 2038, and the use of CCS with 90 percent capture by 2035.

1. Heat-Rate Improvements

The EPA believes that heat rate improvements for existing combustion turbines are broadly applicable today. Heat rate/efficiency improvements can be divided into two types. The first type involves smaller scale improvements to existing combustion turbines. The second type involves more comprehensive upgrades of the combustion turbines.

Smaller scale efficiency improvements can include measures such as inlet fogging and inlet cooling. Both of these techniques can achieve about 2 percent improvements in heat rate. Inlet chilling costs approximately $19/kW and is also accompanied by a capacity increase of 11 percent. Inlet fogging is approximately $0.93/kW and is accompanied by a capacity increase of 6 percent.[565] These small-scale efficiency improvements would likely result in an average 2 percent improvement in the heat rate of affected existing combustion turbines.

More comprehensive efficiency upgrades to combustion turbines are also possible. An upgrade to the combustion turbine can result in a heat rate improvement of 3.0 percent and a capacity increase of 13 percent for $172/kW, while an upgrade to the steam turbine can result in a heat rate improvement of 3.2 percent with a capacity increase of 3 percent for $130/kW. These more comprehensive efficiency improvements would likely result in an average efficiency improvement of 6 percent for affected existing stationary combustion turbines. The EPA is not proposing HRI improvements for units greater than 300 MW because they achieve significantly less emission reductions than either CCS or co-firing hydrogen, but believes that some units may choose to make these upgrades as part of their response to installing CCS and/or co-firing hydrogen. The EPA is taking comment on whether HRI should be considered BSER (or a component of BSER) for combined cycle units with a capacity factor of greater than 50 percent and a capacity of less than 300 MW as part of this initial rulemaking.

2. Co-Firing Low-GHG Hydrogen

a. Overview

The EPA is proposing that for existing combined cycle combustion turbines that operate at capacity factors of greater than 50 percent and that are greater than 300 MW, co-firing 30 percent low-GHG hydrogen by 2032 and 96 percent by 2038 qualifies as the BSER, for largely the same reasons that apply to new combined cycle turbines, as discussed in section VII.F.3.c.vii of this preamble. Co-firing hydrogen at these levels is adequately demonstrated, as indicated by announced plans of manufacturers and generators to undertake retrofit projects for hydrogen co-firing. These plans also indicate that the costs of retrofitting are reasonable. The analysis concerning the costs of low-GHG hydrogen for existing turbines is comparable to the analysis for new turbines. See section VII.F.3.c.vii.(B) of this preamble. Co-firing with low-GHG hydrogen at existing turbines also has comparable non-air quality environmental impacts and energy requirements, and comparable emissions reductions as co-firing with low-GHG hydrogen at new turbines. See sections VII.F.3.c.vii.(C)–(D) of this preamble. For these reasons, the EPA is proposing that co-firing with low-GHG hydrogen qualifies as the BSER. The fact that doing so will also advance the development and deployment of this low-emitting technology further supports this proposal.

b. Adequately Demonstrated

Co-firing with low-GHG hydrogen is feasible in combustion turbines that are currently being produced. Manufacturers have developed retrofits to allow existing combustion turbines to combust up to 100 percent hydrogen, and some companies have announced plans to retrofit their existing turbines to combust hydrogen. In section VII.F.3.c of this preamble, the EPA proposes co-firing of low-GHG hydrogen as BSER for certain new base load combustion turbines. A number of the examples that the EPA cites as evidence that companies are developing combined cycle turbines to co-fire hydrogen either are existing turbines that companies are planning to retrofit to burn hydrogen or are already under construction, and would, therefore, be classified as existing turbines under this rule. Because new combined cycle turbines that operate at capacity factors of greater than 50 percent are similar to existing combined cycle turbines that operate at capacity factors of greater than 50 percent, the EPA is proposing a similar BSER pathway for existing combustion turbines, based upon co-firing 30 percent (by volume) low-GHG hydrogen in 2032 and ramping up thereafter to 96 percent (by volume) low-GHG hydrogen in 2038.

There are two key questions related to whether co-firing low-GHG hydrogen in existing combustion turbines is

[565] *https://www.andovertechnology.com/wp-content/uploads/2021/03/C_18_EDF_FINAL.pdf.*

adequately demonstrated. The first question is whether existing combustion turbines are capable of co-firing significant amounts of hydrogen and/or if they can be retrofitted to do so. The second question is whether there will be an adequate supply of low-GHG hydrogen. These points are discussed below.

i. Capability of Existing Turbines To Co-Fire Hydrogen

There are at least three lines of evidence that demonstrate that co-firing low-GHG hydrogen in existing turbines is possible today (with a number of them already able to fire 100 percent hydrogen) and that by approximately 2030, many additional turbine models will have the capability to co-fire 100 percent hydrogen. First, information from turbine vendors indicates that they already have significant experience in operating turbines with hydrogen; some of their existing turbine models can co-fire hydrogen; and/or they are currently engaged in projects to upgrade existing turbines to co-fire hydrogen. Second, test burns have been completed on several existing utility turbines. Third, several utilities have indicated plans to retrofit existing turbines to co-fire hydrogen.

Existing turbine vendors including GE, Mitsubishi, and Siemens have indicated that their turbines can currently co-fire some amounts of hydrogen; and, they have plans to expand those capabilities. GE has indicated that most of their product line can currently be configured to co-fire significant amounts of hydrogen.[566] Siemens is currently offering retrofit packages for many of its existing turbines that will allow them to combust up to 75 percent hydrogen.[567] Mitsubishi also offers retrofit packages that could allow for up to 100 percent firing of hydrogen.[568]

Section VII.F.3.c.vii(A) of this preamble includes discussion of how retrofitting existing turbines to co-fire with increasing amounts of hydrogen is adequately demonstrated. Several turbines currently in operation have the capability to co-fire hydrogen up to 30 percent without modifications. Other existing turbine models would need modifications to enable co-firing between 50 and 100 percent.

Moreover, several existing combined cycle turbines have demonstrated the ability to co-fire some amounts of hydrogen. The Long Ridge Energy Terminal tested 5 percent hydrogen co-firing at the 485–MW combined cycle plant on a GE HA-class (GE 7HA.02) in 2022. The turbine is designed to enable a transition to 100 percent hydrogen fuel. This example is particularly salient given the large capacity of the unit. No modifications should be required for this turbine model, which has been available since 2017, to operate with between 5 and 20 percent hydrogen co-firing. Higher hydrogen co-firing concentrations will require some modification.[569]

Southern Company has also demonstrated hydrogen co-firing on a Mitsubishi, M501G turbine. The demonstration involved co-firing 20 percent hydrogen (by volume), was successful at both full and partial load, and demonstrated compliance with emissions requirements without impacting maintenance intervals.[570] Other test burns have demonstrated the ability to fire up to 80 percent hydrogen without emissions excursions.[571]

Several utilities are exploring the use of hydrogen in their existing turbine fleet. For example, Constellation Energy, which owns a fleet of 23 gas-fired turbines with a combined total capacity of 8.6 GW, asserts that retrofitting existing turbines to co-fire hydrogen is technically feasible with existing turbine models: ''Based on our assessments, retrofits using available technology can allow hydrogen blending at 50–100 percent by volume in select generators. These retrofits, which include burner and additional balance-of-plant modifications, allow for more substantial CO_2 emissions reductions.'' [572] Florida Power and Light (FPL) intends to convert 16 GW of existing turbine capacity to run on 100 percent hydrogen by 2045.[573] They are currently developing a 25 MW electrolyzer project at the Cavendish Energy Center.[574]

One concern with hydrogen co-firing is that, because it burns at a higher temperature, it has the potential to generate more thermal NOx. The most commonly used NO_X combustion control for base load combined cycle turbines is dry low NO_X (DLN) combustion. Even though the ability to co-fire hydrogen in combustion turbines that are using DLN combustors to reduce emissions of NO_X is currently more limited, all major combustion turbine manufacturers have developed DLN combustors for utility EGUs that can co-fire hydrogen.[575] Moreover, the major combustion turbine manufacturers are designing combustion turbines that will be capable of combusting 100 percent hydrogen by approximately 2030, with DLN designs that assure acceptable levels of NO_X emissions.[576] [577]

ii. Availability of Low-GHG Hydrogen

The EPA is proposing that the BSER for existing combustion turbines includes co-firing 30 percent (by volume) low-GHG hydrogen by 2032 and 96 percent (by volume) by 2038. The EPA is proposing to define low-GHG hydrogen as hydrogen that is produced with overall carbon emissions of less than 0.45 kg CO_2e/kgH2 from well-to-gate. Electrolytic hydrogen produced using zero-carbon emitting energy sources is the most likely, but not the only, form of hydrogen anticipated to meet this proposed definition.[578]

Suitable 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. As referenced throughout this proposal, DOE's clean hydrogen production estimates are 10 MMT annually of clean hydrogen by 2030, and 20 MMT annually by 2040. There is reason to believe actual produced

[566] *https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines?utm_campaign=h2&utm_medium=cpc&utm_source=google&utm_content=eta&utm_term=Ge%20gas%20turbine%20hydrogen&gad=1&gclid=EAIaIQobChMIqMaL6IXG_gIVhsjjBx2gPgb-EAAYASAAEgK61PD_BwE* and *https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-overview.pdf.*

[567] *https://assets.siemens-energy.com/siemens/assets/api/uuid:66b2b6a3-7cdc-404d-9ab0-ddcfbe4adf02/hydrogenflyer.pdf?ste_sid=81945e06dd4f27fd626614f9b954e3f4.*

[568] *https://solutions.mhi.com/clean-fuels/hydrogen-gas-turbine/.*

[569] *https://www.powermag.com/first-hydrogen-burn-at-long-ridge-ha-class-gas-turbine-marks-triumph-for-ge/.*

[570] *https://www.powermag.com/southern-co-gas-fired-demonstration-validates-20-hydrogen-fuel-blend/.*

[571] *https://www.ccj-online.com/real-world-experience-firing-hydrogen-natural-gas-mixtures/.*

[572] Constellation Energy Corporation's Comments on EPA Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units.

[573] *https://cleanenergy.org/blog/nextera-sets-goal-to-decarbonize-proposes-big-transition-for-florida-power-light/.*

[574] *https://dailyenergyinsider.com/news/34040-florida-power-light-taps-cummins-for-its-green-hydrogen-facility/.*

[575] Siemens Energy (2021). Overcoming technical challenges of hydrogen power plants for the energy transition. NS Energy. *https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/.*

[576] Simon, F. (2021). *GE eyes 100% hydrogen-fueled power plants by 2030. https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.*

[577] Patel, S. (2020). *Siemens' Roadmap to 100% Hydrogen Gas Turbines. https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/.*

[578] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (March 2023).

low-GHG hydrogen will exceed those levels. Announced clean hydrogen production projects total 12 MMT annually for 2030.[579] In fact, hydrogen production could outpace DOE's projections if demand markets across sectors, including the power sector, grow rapidly and emerge simultaneously with cost declines across the value chain.[580] Over time, the emergence of the self-sustaining low-GHG hydrogen markets are predicted to be established as demand for low-GHG solidifies and anchors the market, ensuring low-GHG production even after the PTC sunsets. Given the magnitude of the PTC for low-GHG hydrogen, $3/kg, electrolytic hydrogen production is expected to accelerate, accounting for between 70 and 95 percent of hydrogen production in 2030, and between 30 and 50 percent in 2040.[581]

Further, multiple utilities are pursuing projects to secure supplies of electrolyzer-based hydrogen for their power projects. As mentioned earlier in this proposal, Intermountain Power is working with partners to develop an integrated hydrogen turbine, a hydrogen production facility, and a hydrogen storage facility in Delta, Utah. All three components of the project are under construction and are scheduled to be operational by 2025, with the turbine combusting 30 percent (by volume) low-GHG hydrogen at startup.[582] FPL has announced plans to build 30 GW of excess solar to supply clean hydrogen production to power its turbines and to sell to other customers.[583] Entergy has entered into multiple agreements to explore the use of existing and new renewable generating assets and transmission to supply zero GHG electricity to developers of hydrogen production plants.[584] Multiple US utilities are collaborating to develop hydrogen hubs.[585]

c. Costs

The 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.

The EPA has also developed a more specific description of the costs, which follows. It incorporates some components of the analysis of costs of co-firing low-GHG hydrogen for new turbines, as discussed in section VII.F.3.c.vii(B) of this preamble.

There are three sets of potential costs associated with retrofitting combustion turbines to co-fire hydrogen: (1) Capital costs of retrofitting combustion turbines to have the capability of co-firing hydrogen; (2) pipeline infrastructure to deliver hydrogen; and (3) the fuel costs related to production of low-GHG hydrogen. While many combustion turbines are able to fire lower volume blends of hydrogen with natural gas, not all have the capacity or on-site infrastructure necessary to blend higher volumes of hydrogen. The primary costs that combustion turbines would incur would be the fuel costs for low-GHG hydrogen, along with limited capital retrofit costs, in order to co-fire hydrogen at the 30 percent and 96 percent levels that the EPA is proposing as the BSER.

One company, Constellation Energy Corporation, has estimated the costs to retrofit existing plants to co-fire hydrogen and has indicated that they are reasonable: ''We expect $10–$60/kW in retrofit costs to achieve 30–60% hydrogen blending by volume at our power plants. At blend levels in the range of 60–100%, OEMs have suggested pricing of roughly $100/kW.'' [586] The EPA estimates that if low-GHG hydrogen is available at a delivered price of $1/kg,[587] co-firing 30 percent hydrogen in a combined cycle EGU operating at a capacity factor of 65 percent would increase the levelized cost of electricity (LCOE) by $2.9/MWh and a 96 percent co-firing rate would increase the LCOE by $21/MWh.[588] Regardless of the level of hydrogen co-firing, the CO_2 abatement cost is $64/ton ($70/metric ton) at the affected facility.[589] For an aeroderivative simple cycle combustion turbine operating at a capacity factor of 40 percent, the EPA estimates co-firing 30 percent low-GHG hydrogen would increase the LCOE by $4.1/MWh, and a 96 percent co-firing rate would increase the LCOE by $30/MWh. At a delivered price of $0.75/kg, the CO_2 abatement costs for co-firing hydrogen would be $32/ton ($35/metric ton). For a combined cycle EGU, the EPA estimates the LCOE increase would be $1.4/MWh and $11/MWh for the 30 percent and 96 percent cases, respectively. For a simple cycle EGU, the EPA estimates the LCOE increase would be $2.1/MWh and $15/MWh for the 30 percent and 96 percent cases, respectively.

The EPA is soliciting comment on what additional costs would be required to ensure that combustion turbines are able to co-fire between 30 to 96 percent low-GHG hydrogen and if there are efficiency impacts from co-firing hydrogen. Retrofits to add the capacity to combust higher volumes of hydrogen could include retrofitting the combustor, increasing the size of the fuel piping, and upgrades to minimize fuel leakage, hydrogen storage and blending equipment, upgraded control systems, modification to the continuous emissions monitoring system, safety upgrades and leakage detectors, modification of the HRSG to accept higher temperature exhaust, and NO_X control modifications (*e.g.,* upgraded premix combustion technologies).[590] According to model plant estimates in EPRI's US-REGEN model, the heat rate of a hydrogen-fired combustion turbine is 5 percent higher than a comparable natural gas-fired combustion turbine. Furthermore, for hydrogen-fired combustion turbines relative to a comparable natural gas-fired combustion turbine, the capital costs are

[579] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.* Figure 8 of the Liftoff Report represents compiled clean hydrogen projects with aggregated 2030 production exceeding 12 MMT annually.

[580] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.* Figure 13 presents modeling of hydrogen production volumes under various scenarios, including projections of 20MMT in 2030, and 42 MMT in 2040 based on high end of ranges for end use demand which assumes additional ramp up in policy support for decarbonization—which is consistent with this proposal to reduce emissions from the power sector, as well as EPA's proposed Greenhouse Gas Emissions Standards for Heavy-Duty Vehicle.

[581] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023. *https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.* Figure 14 of the Liftoff report projects the split of hydrogen production in future years between electrolytic and SMR.

[582] *https://www.ipautah.com/ipp-renewed/.*

[583] *https://cleanenergy.org/blog/nextera-sets-goal-to-decarbonize-proposes-big-transition-for-florida-power-light/.*

[584] *https://www.entergynewsroom.com/news/entergy-texas-new-fortress-energy-partner-advance-hydrogen-economy-in-southeast-texas/* and *https://www.entergynewsroom.com/news/entergy-texas-monarch-energy-collaborate-advance-southeast-texas-energy-infrastructure-1323187465/.*

[585] *https://news.duke-energy.com/releases/major-southeast-utilities-establish-hydrogen-hub-coalition.*

[586] Constellation Energy Corporation's Comments on EPA Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units Docket ID No. EPA–HQ–OAR–2022–0289, June 6, 2022).

[587] The delivered price includes the purchase cost of the fuel and its transportation costs and the 45V tax credit.

[588] The EIA long-term natural gas price for utilities is $3.69/MMBtu.

[589] The abatement cost of co-firing low-GHG hydrogen is determined by the relative delivered cost of the low-GHG hydrogen and natural gas.

[590] Simon, Nima, Retrofitting Gas Turbine Facilities for Hydrogen Blending. November 2, 2022. *https://www.icf.com/insights/energy/retrofitting-gas-turbines-hydrogen-blending.*

approximately $70/kW higher, the fixed operating costs are approximately $1/year per kW higher, and the non-fuel variable operating costs are approximately $0.5/MWh higher.[591] While these costs are for new combustion turbines, the amounts could be higher for retrofits to combustion turbines. To the extent it is appropriate to account for additional costs associated with a hydrogen co-firing BSER for existing combustion turbines, the EPA is soliciting comment on whether capital and fixed costs should be increased by 9 percent, consistent with the NETL estimated retrofit costs of CCS relative to new combustion turbines.

The EPA is proposing to determine that the increase in operating costs from a BSER based on low-GHG hydrogen is reasonable.

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

The co-firing of hydrogen in combustion turbines in the amounts that the EPA proposes as the BSER would not have adverse non-air quality health and environmental impacts. It would potentially result in increased production of NO_X, but those NO_X emissions can be controlled, as described in sections VII.F.3.c.vii.(A) and XI.C.2.b.i of this preamble.

In addition, co-firing hydrogen in the amounts proposed would not have adverse impacts on energy requirements, including either the requirements of the combustion turbines to obtain fuel or on the energy sector more broadly, particularly with respect to reliability. As discussed in sections VII.F.3.c.vii.(A)–(B) and XI.C.2.b.–c. of this preamble, combustion turbines can be constructed to co-fire high volumes of hydrogen in lieu of natural gas, and the EPA expects that low-GHG hydrogen will be available in sufficient quantities and at reasonable cost. Any impact on the energy sector would be further mitigated by the large amounts of existing generation that would not be subject to requirements in this rule and the projected new capacity in the base case modeling.

e. Extent of Reductions in CO_2 Emissions

The site-specific reduction in CO_2 emissions achieved by a combustion turbine co-firing hydrogen is dependent on the volume of hydrogen blended into the fuel system. Due to the lower energy density by volume of hydrogen compared to natural gas, an affected source that combusts 30 percent by volume hydrogen with natural gas would achieve approximately a 12 percent reduction in CO_2 emissions versus firing 100 percent natural gas.[592] A source combusting 100 percent hydrogen would have zero CO_2 stack emissions because hydrogen contains no carbon, as previously discussed. A source co-firing 96 percent by volume hydrogen (approximately 89 percent by heat input) would achieve an approximate 90 percent CO_2 emission reduction, which is roughly equivalent to the emission reduction achieved by sources utilizing 90 percent CCS.

f. Promotion of the Development and Implementation of Technology

Determining co-firing 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent (by volume) to be components of the BSER would generally advance technology development in both the production of low-GHG hydrogen and the use of hydrogen in combustion turbines, for the same reasons discussed with respect to new combustion turbines in section VII.F.3.c.vii.(E) of this preamble.

g. Summary

The EPA proposes that co-firing 30 percent low-GHG hydrogen by 2032 and 96 percent by 2038 qualify as a BSER pathway for large and frequently-used existing combustion turbines. For the reasons discussed above, the EPA proposes that co-firing low-GHG hydrogen on that pathway is adequately demonstrated in light of the capability of combustion turbines to co-fire hydrogen and the EPA's reasonable expectation that adequate quantities of low-GHG hydrogen will be available by 2032 and 2038 and at reasonable cost. Moreover, combusting hydrogen will achieve reductions because it does not produce GHG emissions and will not have adverse non-air quality health or environmental impacts or energy requirements, including on the nationwide energy sector. Primarily because the production of low-GHG hydrogen generates the fewest GHG emissions, the EPA proposes that co-firing low-GHG hydrogen, and not other types of hydrogen, qualify as the ''best'' system of emission reduction. See section VII.F.3.c.vii(F) of this preamble. The fact that co-firing low GHG hydrogen creates market demand for, and advances the development of, low-GHG hydrogen, a fuel that is useful for reducing emissions in the power sector and other industries, provides further support for this proposal.

Similar to new base load combined cycle turbines, the EPA is also taking comment on an alternative approach in which the BSER for these units would be based on CCS with 90 percent capture, for the reasons discussed next, but units could follow a pathway that would enable them to achieve the same reductions using low-GHG hydrogen.

3. CCS

a. Overview

The EPA believes that CCS is an effective mitigation measure for existing combustion turbines and that it would be most cost-effective for units that are frequently operating. As discussed in section VII.F.3.b.iii.(A) of this preamble, multiple companies are considering adding CCS to existing fossil fuel-fired power plants and multiple companies have performed FEED studies evaluating the feasibility of installing CCS on an existing combined cycle unit. As also discussed there, CO_2 pipelines are available and their network is expanding in the U.S., the safety of existing and new supercritical CO_2 pipelines is comprehensively regulated by PHMSA, and areas without reasonable access to pipelines for geologic sequestration can transport CO_2 to sequestration sites via other transportation modes. As also discussed there, geologic sequestration of CO_2 is well proven, broadly available throughout the U.S., and there is a detailed set of regulatory requirements to ensure the security of sequestered CO_2. For these reasons, the EPA proposes that CCS with 90 percent capture is adequately demonstrated for existing combustion turbines.

The EPA further proposes that CCS is cost-reasonable for existing turbines that are greater than 300 MW and operate at greater than 50 percent capacity. The EPA believes that many existing combined cycle units are likely to be able to install and operate CCS within the costs that the EPA found to be reasonable for new stationary combustion turbines and existing coal-fired steam generating units. Certain parts of the cost calculation should be much the same as for new sources, including the costs for transportation and sequestration as well as the availability of the IRC section 45Q tax credit, although the costs for retrofitting capture equipment may in some cases be higher. See section VII.F.3.b.iii.(B) of this preamble. NETL estimates that the capital cost of CCS retrofits on combined cycle EGUs is 9 percent

[591] *https://us-regen-docs.epri.com/v2021a/assumptions/electricity-generation.html#new-generation-capacity.*

[592] The energy density by volume of hydrogen is lower than natural gas.

higher than for new combined cycle EGUs.[593] The additional capital costs increase the LCOE of the retrofit CCS by an additional $1.5/MWh compared to an installation at a new combined cycle EGU, which is consistent with control costs that EPA has found to be reasonable in other rulemakings, as noted in section VII.F.3.b.iii.(B)(5).

The ability to cost-effectively apply CCS was a significant consideration in the EPA's selection of proposed capacity and utilization thresholds to determine which existing turbines would be covered by these proposed emission guidelines. The EPA considered two primary factors in evaluating an appropriate capacity threshold. The first is emission reduction potential. As the capacity threshold decreases a larger amount of the existing fleet is covered and overall emission reduction potential increases. For instance, at a 500 MW threshold, only 2 percent of the capacity and 7 percent of the emissions are covered. The second factor the EPA considered was capacity to build CCS. In 2030, the EPA projects that approximately 12 GW of coal-fired generation will likely install CCS (including both CCS being installed to meet requirements of this rule and CCS that EPA projects would occur even without the requirements proposed here). There are likely to also be a number of other CCS projects for other industries developed in the 2023 through 2030 timeframe. Multiple industries including the ethanol industry and the hydrogen production sector have announced post combustion CCS projects in response to the IRA.

The EPA believes it is reasonable to assume therefore that by 2035 there will be a larger capability to build CCS retrofits than in 2030. Had the EPA proposed capacity thresholds of 400 MW or 500 MW, they would have only resulted in the need for a maximum of 12 GW or 6 GW of CCS capacity respectively by 2035 for existing gas turbines covered by this proposal, which is less than the CCS capacity the EPA projects in 2030 to meet the existing coal BSER. That would likely mean foregoing feasible, cost-effective emissions reductions. By contrast, the 300 MW cutpoint that EPA is proposing would require up to 37 GW of CCS in 2035. While this is approximately 3 times the amount of CCS that the EPA is projecting for coal-fired units in 2030, the EPA believes that 300 MW is a reasonable threshold primarily because there will be significant time to deploy the needed infrastructure, a total of eleven years from the likely finalization of these guidelines. In addition, it is unlikely that all of the units that EPA projects would be affected in 2035 would choose to install CCS; some would likely choose to co-fire low-GHG hydrogen.[594] For these reasons, the EPA believes that there will be adequate capability to build enough CCS for the existing combustion turbine EGUs subject to a CCS BSER at a capacity threshold of 300 MW, given the amount of time provided.

The EPA also considered a capacity threshold of 200 MW and of 100 MW. According to the EPA's projections, a threshold of 200 MW would affect a total of 85 GW, and a threshold of 100 MW would affect 134 GW of existing combustion turbine capacity. While the EPA believes that it is possible that the industry could install that amount of CCS on this timeline, the EPA believes it is important to gather more information on the question of how quickly CCS can be deployed and is therefore taking comment on, but not proposing, a lower capacity threshold of 200 MW or 100 MW, and taking comment on whether it would be feasible to install CCS and or co-fire hydrogen for the 85 GW or 134 GW of units it projects would be covered under those thresholds and a capacity factor of greater than 50 percent.

Historical rates of emission control technology retrofits at existing coal-fired power plants, such as flue gas desulfurization (FGD), indicate that rapid deployments of such technologies in response to regulatory requirements have proven feasible historically in the United States and elsewhere. FGD was rapidly deployed in the United States in response to various regulatory requirements, including the 1971 NSPS addressing SO_2 emissions. Although other compliance options were available, FGD—a wholly new technology—was installed on 48 GW of coal-fired power plants between 1973 and 1984,[595] while the number of technology vendors went from 1 to 16.[596] Similarly, Germany subsequently increased its share of FGD from 10 to 79 percent in four years.[597 598] It should be noted that as FGD became a more familiar technology, installation rates accelerated, reaching nearly 30 GW a year in the United States.[599] A very rapid ramp up happened after the Clean Air Interstate Rule, for example, where the installed capacity increased from 131 GW in 2007 to 200 GW in under four years.[600] There are many differences between FGD and CCS, but the history of the rapid build-out of FGD generally supports the EPA's view that companies with the expertise to install complex emission control equipment can rapidly ramp up capacity in response to a regulatory driver.

The EPA seeks comment on the feasibility of setting a threshold of 100 or 200 MW and a 40 percent capacity factor in light of these examples and other relevant considerations. As further described below, the EPA further proposes that CCS with 90 percent capture for existing combustion turbines greater than 300 MW and operating at more than 50 percent capacity meets the other criteria to qualify as the BSER, for the same reasons as it does for new combustion turbines in the baseload subcategory:

b. Adequately Demonstrated

Section VII.F.3.b of this preamble includes discussion of how CCS with a 90 percent capture rate has been adequately demonstrated and is technically feasible based on the demonstration of the technology at existing coal-fired steam generating units and industrial sources in addition to combustion turbines. Notably, the function, design, and operation of post-combustion CO_2 capture equipment is similar, although not identical, for both steam generating units and combustion turbines. As a result, application of CO_2 capture at existing coal-fired steam generating units helps show that it is adequately demonstrated for combustion turbines as well.

[593] Tommy Schmitt, Sally Homsy, National Energy Technology Laboratory, Cost and Performance of Retrofitting NGCC Units for Carbon Capture—Revision 3, March 17, 2023 (DOE/NETL–2023/3848).

[594] Approximately 6 GW of the capacity projected to operate at a capacity factor of greater than 50 percent in the EPA's modeling is owned by NextERA who has already announced intentions to convert much of their combined cycle turbines to co-fire increasing amounts of hydrogen.

[595] Van Ewijk, S., McDowall, W. Diffusion of flue gas desulfurization reveals barriers and opportunities for carbon capture and storage. *Nat Commun* 11, 4298, Figure 1 and Source Data (2020), *available at https://doi.org/10.1038/s41467-020-18107-2.*

[596] Taylor, et al., *Regulation as Mother of Innovation,* 27 Law & Pol'y 348, 356 (2005).

[597] Van Ewijk, S., McDowall, W. Diffusion of flue gas desulfurization reveals barriers and opportunities for carbon capture and storage. *Nat Commun* 11, 4298 (2020). *https://doi.org/10.1038/s41467-020-18107-2.*

[598] Similarly, in response to regulatory requirements over 100 GW of coal-fired generation installed selective catalytic reduction (SCR) between 1999 and 2009, ramping from very low levels. Healey, Scaling and Cost Dynamics of Pollution Control Technologies, at 7, Figure 3 (2013). *https://core.ac.uk/download/pdf/44737055.pdf.*

[599] Markussan, *Scaling up and Deployment of FGD in the US (CCS—Releasing the Potential)* (2012) at v, 24.

[600] Electric Power Annual 2015, *https://www.eia.gov/electricity/annual/archive/pdf/03482015.pdf.*

In the retrofit context, SaskPower's Boundary Dam Unit 3, a 110 MW lignite-fired unit in Saskatchewan, Canada, has demonstrated 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, was the first full-scale CO_2 capture system retrofit on an existing coal-fired power plant.[601] Other references detailed in section VII.F.3.b.iii.(A).(2) provide additional support for the demonstration of CO_2 capture retrofits.

Moreover, section VII.F.3.b.iii.(A)(3) of this preamble describes how CCS has been successfully applied to a combined cycle EGU (the Bellingham Energy Center in south central Massachusetts) and how several other projects are in development. Both section VII.F.3.b.iii.(A)(3) of this preamble and the TSD on *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines* discuss several CCS projects under development involving retrofits to existing NGCC units.

In addition to CO_2 capture, the CO_2 transport and geologic storage aspects of CCS systems are also adequately demonstrated, as discussed in section VII.F.3.b and section X.D.1.a of this preamble and in the *GHG Mitigation Measures for Steam Generating Units* TSD. Geologic sequestration potential for CO_2 is widespread and available throughout the U.S. Nearly every State in the U.S. has or is in close proximity to formations with geologic sequestration potential, including areas offshore. These areas include deep saline formation, unmineable coal seams, and oil and gas reservoirs. Additionally, the U.S. CO_2 pipeline network has steadily expanded (with 5,339 miles in operation in 2021, a 13 percent increase in CO_2 pipeline miles since 2011), and appears primed to continue expanding, with several major projects recently announced across the country. Areas without reasonable access to pipelines for geologic sequestration can transport CO_2 to sequestration sites via other transportation modes such as ship, road tanker, or rail tank cars.

c. Costs

The EPA is proposing that the costs of CCS are reasonable for existing combustion turbines that are large and frequently used. As further discussed in the Regulatory Impact Analysis and the *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines* TSD, the EPA's approach relies on cost and performance assumptions consistent with the IPM post-IRA 2022 reference case.[602] The EPA's baseline shows that 7 GW of existing natural gas combined cycle capacity retrofits with CCS in 2030, rising to 10 GW in 2035. The significant deployment of CCS on combined cycle natural gas EGUs in the absence of emission standards reinforces the cost reasonableness and feasibility of the proposed standards.

Section VII.F.3.b.iii.(B) and section X.D.1.a.ii of this preamble discuss the cost-reasonableness of CCS technology in the context of new combustion turbines and existing coal-fired steam generating units. Additionally, a March 2023 NETL report estimates that the capital cost of CCS retrofits on combined cycle EGUs is 9 percent higher than for installation of CCS equipment on new greenfield combined cycle EGUs.[603] The higher retrofit costs account for the cost premium for design, construction, and tie-in constraints imposed by existing plant layout and operation. The additional capital costs increase the LCOE of the retrofit CCS by an additional \$2.2/MWh compared to an installation at a new combined cycle EGU.[604] Assuming the same model plant, a 90 percent-capture retrofit amine-based post combustion CCS system increases the LCOE by \$8.6/MWh and has overall CO_2 abatement costs of \$26/ton (\$28/metric ton). Similar to NETL estimates for greenfield CCS projects, costs at a specific plant would be expected to vary somewhat from this estimate, as it does not include site and plant-specific considerations such as seismic conditions, local labor costs, or local environmental regulations.

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

As in the context of new NGCC units and existing coal-fired steam generating units (discussed in section VII.F.3.b.iii.(C) and section X.D.1.a.iii of this preamble), the EPA does not expect the use of CCS at large, frequently used existing combustion turbines to have unreasonable adverse consequences related to non-air quality health and environmental impact or to energy requirements.

Regarding energy requirements, upon retrofitting an NGCC plant with CCS, a derate in the net plant electrical output will be incurred due to the parasitic/auxiliary energy demand required to run the CCS system, as well as steam extraction from the steam cycle to satisfy the CCS reboiler duty.[605] As discussed in the TSD on *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* a recent NETL report has estimated that the resulting derates for 90 percent CO_2 capture retrofits range from an 11.5 to 11.8 percent loss of net MWe.

Despite decreases in efficiency, IRC section 45Q tax credits provide an incentive for increased generation with full operation of CCS because the credits are proportional to the amount of captured and sequestered CO_2 emissions and not to the amount of electricity generated. The EPA is proposing that the energy penalty is relatively minor compared to the GHG benefits of CCS. The EPA does not believe that determining CCS to be BSER for large, frequently operated combustion turbines will cause reliability concerns. This is because of the limited increase in costs and energy penalty due to CCS, coupled with the amounts of smaller or lower capacity generation that would not be subject to these requirements and the projected new capacity in the base case modeling. For the estimated 37 GW of facilities that would face requirements under this proposal, if they all installed CCS retrofit the reduction in available capacity would be approximately 4.3 GW, or less than 1% of the total modeled available natural gas capacity in 2035. Grid planners, operators, and market participants can address the potential, marginal impact, through development of a similarly small increment of accredited capacity, whether from new natural gas simple cycle turbine

[601] 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.*

[602] These assumptions are detailed at: *https://www.epa.gov/system/files/documents/2023-03/Chapter%206%20-%20CO2%20Capture%2C%20Storage%2C%20and%20Transport.pdf.*

[603] Cost and Performance of Retrofitting NGCC Units for Carbon Capture—Revision 3 (DOE/NETL–2023/3848, March 17, 2023). *https://www.netl.doe.gov/projects/files/CostandPerformanceofRetrofittingNGCCUnitsforCarbonCaptureRevision3_031723.pdf.*

[604] These calculations use the NETL F-Class turbine, a service life of 12 years, an interest rate of 7.0 percent, a natural gas price of \$3.69/MMBtu, a capacity factor of 75 percent, a transport, storage, and monitoring cost of \$10/metric ton, and a 45Q tax credit of \$85/metric ton.

[605] *Cost and Performance of Retrofitting NGCC Units for Carbon Capture—Revision 3.* (DOE/NETL—2023/3848, March 17, 2023). *https://www.osti.gov/biblio/1961845.*

deployment, new energy storage, or new sources of clean energy.

Regarding non-air quality health and environmental impact, criteria or hazardous air pollutant emissions would in general be mitigated or adequately controlled by equipment needed to meet other CAA requirements, and the EPA's assessment is that the additional cooling water requirements from CCS at NGCC units are reasonable, as discussed in section VII.F.3.v.iii.(C). 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. CCS projects undertaken pursuant to these emission guidelines will, if the EPA finalizes proposed revisions to the CAA section 111 implementing regulations,[606] be subject to requirements for meaningful engagement as part of the State plan development process. See section XII.F.1.b of this preamble for additional details.

e. Extent of Reductions in CO_2 Emissions

Designating CCS with 90 percent capture as a component of the BSER for large and frequently-operated combustion turbines prevents large amounts of 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.

f. Promotion of the Development and Implementation of Technology

The EPA also considered whether determining CCS to be a component of the BSER for existing large and frequently operated combustion turbines will advance the technological development of CCS and concluded that this factor supports our BSER determination. Combined with the availability of 45Q tax credits and investments in supporting CCS infrastructure from the IIJA, this requirement should incentivize additional use of CCS, which should, in turn, incentivize cost reductions through the development and use of better performing solvents or sorbents. While solvent-based CO_2 capture has been adequately demonstrated at the commercial scale, a determination of the BSER for certain existing combustion turbines (along with new baseload combustion turbines and long term coal-fired steam generating units) is the use of CCS will also likely incentivize the deployment of alternative CO_2 capture techniques at scale. Moreover, as noted above, the cost of CCS has fallen in recent years and is expected to continue to fall; and further implementation of the technology can be expected to lead to additional cost reductions, due to added experience and cost efficiencies through scaling.

The EPA seeks comment on the feasibility of setting a threshold for inclusion in the existing combustion turbine segment to be addressed by the emission guidelines proposed here of 100 or 200 MW and a 40 percent capacity factor in light of the examples of other historic deployment of pollution controls and other relevant considerations. DOE recently released a report discussing the State of carbon management technology.[607] In that report, DOE states that with policy support (either via regulation or incentives) or technology premiums for low-carbon products (*e.g.,* low embodied carbon steel and concrete) the scale up of CCS technologies and pipeline and storage infrastructure would proceed much faster for the power sector than will proceed absent additional policy support or market demand.[608] In the report, DOE states that regulatory developments, in particular, could play a dramatic role in accelerating the pathways described for industries with lower-purity CO_2 streams such as power plants. The report states that absent additional incentives, CCS technology for the power sector is likely to significantly scale between 2030–2040 with pilot and demonstration technologies occurring now. As detailed in the report, several incentives have recently become available or been significantly increased that will accelerate the deployment of CCS for the power sector. The 45Q tax credit for CCS is a strong incentive, and DOE is already investing heavily through the Bipartisan Infrastructure Law at further demonstrating lower-purity CCS technologies such as those used in the power sector, which will help to decrease costs and establish repeatable commercial arrangements.

As the DOE report discusses, CO_2 pipelines also need to be further built out for CCS technologies to scale. CO_2 pipelines are the most mature, and often the most cost-effective CO_2 transport technology for high volumes and will likely form the backbone of CO_2 transport. PHMSA reported that 5,339 miles of CO_2 pipelines were in operation in 2021.[609] Analogous historical build out of inter- and intrastate natural gas transmission pipelines demonstrates that similar levels of CO_2 pipeline deployment are feasible. Data reported by EIA indicates that from 1997 to 2008 over 25,000 miles of natural gas transmission pipeline was constructed, averaging over 2,000 miles per year.[610] 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.[611] This is in line with the historical maximum deployment of natural gas transmission pipelines, and also does not account for any economies of scale from pipeline systems developed for capture from other non-power CO_2 sources.

D. Areas That the EPA Is Seeking Comment on Related to Existing Combustion Turbines

The EPA is seeking comment on four general areas related to selecting the BSER for existing combustion turbines. First, the EPA is soliciting comment on general assumptions about potential future utilization of combustion turbines. Second, the EPA is soliciting comment on assumptions about the appropriate group of existing combustion turbine units to be addressed in this rulemaking. Third, the EPA is requesting comment on the appropriate BSER for those turbines. Fourth, the EPA is requesting comment

[606] 87 FR 79176, 79190–92 (December 23, 2022).

[607] DOE Carbon Management Demonstration and Deployment Pathway, April 2023, *https://liftoff.energy.gov/*

[608] The Federal Buy Clean Task Force and the First Mover's Coalition are both seeking to provide a clear demand signal for low embodied emissions products.

[609] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2021. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[610] *https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.*

[611] Middleton, Richard and Bennett, Jeffrey and Ellett, Kevin and Ford, Michael and Johnson, Peter and Middleton, Erin and Ogland-Hand, Jonathan and Talsma, Carl, *Reaching Zero: Pathways to Decarbonize the US Electricity System with CCS* (August 30, 2022). Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT–16) 23–24 Oct 2022. *https://ssrn.com/abstract=4274085* or *http://dx.doi.org/10.2139/ssrn.4274085.*

on the timing of BSER requirements for existing combustion turbines.

The EPA is seeking comment on a number of issues related to how its consideration of projected future utilization of combined cycles informed its consideration of a potential BSER for existing combustion turbines. First, the EPA is taking comment on its projections of how combustion turbines will operate in the future and the key factors that influence those changes in operation. While the EPA modeling shows that there is some increase in emissions from these units in all years following imposition of CAA section 111 standards on existing coal-fired steam generating units and new stationary combustion turbines, that increase is much smaller in the later years. The EPA believes the magnitude of these trends is significantly impacted by the rate at which new low emitting generation comes on-line, in part incentivized by IRA and IIJA. The EPA is taking comment on all aspects of these assumptions including: the speed at which new low-emitting generation will come on-line and the impact that it has on likely capacity factors for combined cycle units (in particular the projection that capacity factors will grow in the 2028/30 timeframe but decrease in later years).

With regard to the size and definition of the category to be covered in a first rulemaking covering only part of the existing turbine category, the EPA is also taking comment on how its assumptions about the potential operation of combustion turbines in future years coupled with considerations about the availability of infrastructure should inform which units should be covered in a first rulemaking. More specifically, the EPA is requesting comment on how to consider the rate of CCS (and potentially hydrogen) infrastructure development in determining a BSER that could potentially impact hundreds of sources. If, for instance, increased renewable generation and storage capacity were to lead to a smaller number of units operating at capacity factors of greater than 50 percent, the proposed BSER would not affect as many units and a smaller size threshold might be possible without expanding the amount of infrastructure needed. Conversely, if more units were likely to operate at a higher capacity factor, a higher capacity threshold might be appropriate. If the number of units likely to be covered by a 50 percent threshold were sufficiently small, it might be reasonable to include units in the intermediate category (*e.g.,* units with capacity factors of between 20 percent and 50 percent) in a first rulemaking addressing the existing fossil fuel-fired turbine category. The EPA is also taking comment on a lower capacity factor threshold (*e.g.,* 40 percent) and a lower capacity threshold (200 MW or 100 MW, and capacities between 100 and 300 MW). With regards to units with a capacity factor of greater than 50 percent that are under 300 MW and units with a capacity factor of 50 percent or less the EPA is taking comment on the appropriateness of CCS and/or hydrogen as a BSER. With regards to hydrogen, the EPA is taking comment on the appropriate level of and timing for hydrogen co-firing. More generally, EPA is requesting comment on any feasibility issues related to broader CCS deployment should those thresholds be adjusted such that more coal capacity is affected, and how such issues could be addressed.

With regards to the BSER itself, the EPA is soliciting comment on the applicability of CCS retrofits to existing combustion turbines and its focus on base load turbines (*e.g.,* those with a capacity factor of greater than 50 percent). This solicitation includes comment on whether particular plants would be unable to retrofit CCS, including details of the circumstances that might make retrofitting with CCS unreasonable or infeasible.

The EPA is also taking comment on the role of low-GHG hydrogen as part of BSER. More specifically, the EPA is requesting comment on the appropriateness of low-GHG hydrogen as a BSER for combustion turbines larger than 300 MW with capacity factors of greater than 50 percent. While, as has been noted earlier in this section, a number of turbines already exist or are under construction that owners of combustion turbines have indicated may burn large amounts of hydrogen in a base load mode, the EPA is also aware that other proponents of low-GHG hydrogen use in turbines focus on it primarily as an energy storage device, storing renewable energy to provide electricity in times where renewable energy was not available. The EPA is interested in the question of whether, in this case, it would be likely that a combined cycle turbine burning low-GHG hydrogen would operate near base load, and whether it be prudent to have an alternative BSER or an alternative compliance pathway for units combusting low-GHG hydrogen and solicits comments on these questions. Similar to the NSPS for base load combustion turbines, the EPA is also taking comment on whether to finalize both the proposed low-GHG hydrogen BSER and the proposed CCS with 90 percent capture BSER, or finalize a BSER with a single pathway, such as based on application of CCS with 90 percent capture, which could also be met by co-firing with low-GHG hydrogen.

With regard to the timing for BSER, the EPA is taking comment on a 2035 CCS based BSER standard and whether that standard could reasonably be applied earlier. Similarly, the EPA is taking comment on the timing of a low-GHG hydrogen based BSER and whether a 30 percent low-GHG hydrogen standard could be implemented earlier than 2032, or if low-GHG hydrogen supply infrastructure development suggests it should be later. The EPA is taking comment on the same questions with regard to a 96 percent low-GHG hydrogen co-firing BSER in 2038.

E. BSER for Remaining Combustion Turbines

While the EPA believes that emission guidelines for units covered in the first rulemaking, proposed above, can achieve important emission reductions from the most frequently operating combustion turbines, the EPA believes that limits to infrastructure and capability to build carbon capture systems or co-fire large amounts of hydrogen caution against a first rulemaking addressing emissions from existing turbines covering all combustion turbines. In this section, the EPA discusses how developing a BSER for units in a second rulemaking could address units that do not meet the applicability requirements for the first rulemaking.

As noted above, the EPA is taking comment on what units should be part of whatever action the EPA finalizes as a result of the proposal. Based on the units that the EPA has proposed be included, units that might remain uncovered include smaller baseload units (*e.g.,* those less than or equal to 300 MW) and all units operating less than or equal to a capacity factor of 50 percent. Particularly for the remainder of the baseload units, the EPA is interested in whether any other units should have a BSER based on CCS. The EPA is also interested in the timing of such a requirement recognizing the tensions between an earlier requirement that would both achieve earlier reductions and the need to allow time for infrastructure to develop to support growing amounts of CCS.

For intermediate turbines, the EPA is taking comment on a BSER similar to that for new turbines. In particular, the EPA is interested in comment about an appropriate pathway and timing for a BSER that would ultimately require 96 percent low-GHG hydrogen by volume.

Finally, for peaking turbines, the EPA is interested in comment about whether a clean hydrogen BSER would be appropriate, what the timing of such a requirement should be and whether there should be any phasing.

The EPA is also interested in any comments related to: potential changes in operational patterns for turbines, particularly as more renewables and storage enter the grid. For instance, the EPA is interested in comments as to whether improvements in energy storage will reduce reliance on intermediate and peaking turbines. The EPA is also interested in comments on any potential technology developments that could impact its determination of BSER. For instance, the EPA is aware that in addition to electrolyzer based hydrogen and natural gas based hydrogen, there are other means of hydrogen production receiving significant attention such as naturally occurring hydrogen, and solicits comments on whether any of these potential technology developments should impact the EPA's consideration of the appropriate BSER for the remaining turbines.

XII. State Plans for Proposed Emission Guidelines for Existing Fossil Fuel-Fired EGUs

A. Overview

State plan submissions under these emission guidelines are governed by the requirements of 40 CFR part 60, subpart Ba (subpart Ba).[612] The EPA proposed to revise certain aspects of 40 CFR part 60, subpart Ba, in its December 2022 proposal, ''Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)'' (proposed subpart Ba).[613] The Agency intends to finalize revisions to 40 CFR part 60, subpart Ba, before promulgating these emission guidelines. Therefore, State plan development and State plan submissions under these proposed emission guidelines would be subject to the requirements of subpart Ba as revised in that future final action, including any changes the EPA makes to the proposal in response to public comments. To the extent the EPA is proposing to add to, supersede, or otherwise vary the requirements of subpart Ba for the purposes of these particular emission guidelines, those proposals are explicitly addressed in this section of the preamble. Unless expressly amended or superseded in these proposed emission guidelines, the provisions of subpart Ba, as revised by the EPA's forthcoming final rule, would apply.

This section provides information on several aspects of State plan development, including compliance deadlines, a presumptive methodology for establishing standards of performance for affected EGUs, compliance flexibilities, and State plan components and submission. In sections X and XI of this preamble, the EPA is soliciting comment on ranges for dates and values for defining subcategories, BSER, and degrees of emission limitation; those solicitations for comment extend to the proposed values and dates discussed in this section of the preamble. In section XII.B, the EPA proposes and explains its reasoning for compliance deadlines for affected steam generating units and affected combustion turbines. In section XII.C, the EPA describes its requirement that State plans achieve equivalent stringency to the EPA's BSER. Section XII.D proposes a presumptive methodology for calculating the standards of performance for affected EGUs based on subcategory 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 XII.D also describes proposed requirements for increments of progress for affected EGUs in certain subcategories and milestones for affected EGUs, as well as testing and monitoring requirements. In section XII.E, the EPA proposes that States would be permitted to include trading and averaging as compliance measures for affected EGUs in their State plans, so long as plans demonstrate equivalence to the stringency that would result if each affected EGU was individually achieving its standard of performance. Finally, section XII.F describes what must be included in State plans, including plan components specific to these emission guidelines and requirements for conducting meaningful engagement.

In this section of the preamble, the term ''affected EGU'' means any existing fossil fuel-fired steam generating unit or existing fossil fuel-fired combustion turbine EGU that meets the applicability criteria described in sections X and XI of this preamble. Affected EGUs would be covered by the proposed emission guidelines under 40 CFR part 60 subpart UUUUb.

B. Compliance Deadlines

The EPA is proposing a compliance date of January 1, 2030, for affected steam generating units. The proposed compliance date for the CCS combustion turbine subcategory is January 1, 2035. The proposed compliance dates for the first phase and second phase for the affected hydrogen co-fired combustion turbine subcategory are January 1, 2032, and January 1, 2038, respectively. This means that starting on the applicable compliance date, affected EGUs would be subject to standards of performance and other State plan requirements under these emission guidelines and would be required to start demonstrating compliance with those requirements.

The EPA is proposing that January 1, 2030, is the soonest that affected steam generating units could reasonably commence compliance with standards of performance given the proposed State plan submission timeline (24 months; see section XII.F.2 of this preamble) and the amount of time affected EGUs in the long-term and medium-term coal-fired steam generating unit subcategories will need to install CCS or natural gas co-firing, respectively. For consistency, the EPA is also proposing a January 1, 2030, compliance date for imminent- and near-term coal-fired units as well as the different subcategories of natural gas- and oil-fired steam generating units.

However, the EPA recognizes that the BSERs for some subcategories of affected steam-generating EGUs are routine methods of operation and maintenance, which do not require the installation of any or significant control equipment and can thus be applied earlier.[614] Therefore, the EPA is soliciting comment on compliance dates defined by the date of approval of the State plan or January 1, 2030, whichever is earlier, for imminent-term coal-fired steam generating units, near-term coal-fired steam generating units, and the different subcategories of natural gas- and oil-fired steam generating units.

The proposed compliance timeframe for affected steam-generating EGUs in these proposed emission guidelines is based on the amount of time the EPA believes is needed to comply with standards of performance based on implementation of natural gas co-firing or CCS. Each of these systems would require several years to plan, permit, and construct. However, as explained further in section XII.F.2 of this preamble, the EPA is proposing to

[612] 40 CFR 60.20a–60.29a.

[613] See 87 FR 79176 (December 23, 2022); see also id., Docket ID No. EPA–HQ–OAR–2021–0527–0002 (memorandum to docket containing proposed revisions to 40 CFR part 60, subpart Ba).

[614] The EPA is also taking comment in section X.D.3.b.ii on potential BSER options for imminent- and near-term affected coal-fired steam generating units based on low levels of natural gas co-firing.

adjust the State plan submission deadline so that certain necessary planning and design steps for natural gas co-firing or CCS implementation can take place as part of the State plan development process. That is, we expect that some of the planning and design steps described below would take place prior to State plan submission. The EPA believes that coordinating State plan development, submission, and implementation in this manner reflects how the owners/operators of affected EGUs and States would actually undertake the steps leading to ultimate deployment of a control technology and compliance with a standard of performance.

The *GHG Mitigation Measures for Steam Generating Units* TSD discusses the timeframes for implementation of natural gas co-firing and CCS at existing coal-fired steam generating EGUs. Based on this analysis, it is clear that the time needed to design and implement CCS is an important aspect for setting a compliance date under these emission guidelines. CCS projects will include planning, design, and construction of both the carbon capture system and the transport and storage system; the EPA believes that all of these steps can be completed within roughly 5 years.[615]

Deployment of a carbon capture system starts with a technical and economic feasibility evaluation, including a Front End Engineering Design (FEED) study. The owner/operator of an affected EGU would then proceed to making technical and commercial arrangements, including arranging project financing and permitting. These initial steps do not need to be undertaken sequentially and may be completed in 3 years or less. As noted above, the EPA also believes that at least some of these project design and development steps, including feasibility evaluations and FEED studies, can and will be completed prior to State plan submission. The EPA believes that the commencement of CCS project implementation activities, including more detailed engineering work and procurement, construction of the carbon capture system, and startup and testing, will overlap with the final steps of the initial project design and development phase. These project implementation steps take approximately 3 years to complete.

In addition to planning and implementing a carbon capture system, the owners/operators of affected EGUs will also have to design and construct a system for transporting and storing captured CO_2. The necessary steps for implementing transport and storage of captured CO_2 can be undertaken simultaneously with development of the CO_2 capture system, and some of the steps necessary for transport and storage can additionally overlap with each other. The EPA thus believes design and implementation of CO_2 transport and storage can be completed within 5 years.

The EPA believes that the initial phases of planning and design for CO_2 transport and storage, including site characterization and pipeline feasibility and design activities, can and will occur prior to State plan submission, *i.e.,* as part of the State plan development process. First, the owner/operator of an affected EGU would undertake a feasibility analysis associated with CO_2 transport and storage, as well as site characterization and permitting of potential storage areas. These steps can overlap with each other and the EPA anticipates that, in total, feasibility analyses, site characterization, and permitting of potential storage areas will take 2–3 years to complete. The EPA believes there is significant opportunity to overlap the design and planning phase for CO_2 transport and storage with the engineering and construction phase for transport and storage, which is anticipated to take 2–3 years. Based on the potential to conduct many of the design, planning, permitting, engineering, and construction steps, the EPA thus believes that affected EGUs will need approximately 5 years, from start to finish, to be ready to implement CO_2 transport and storage.

The EPA expects that implementation of natural gas co-firing projects for affected coal-fired steam-generating EGUs, including any necessary construction of natural gas pipelines, can be completed in approximately 3.5 years. As discussed in the *GHG Mitigation Measures for Steam Generating Units* TSD,[616] any necessary boiler modifications to accommodate natural gas co-firing can be completed within 3 years. The process of planning, permitting, and construction for boiler modifications can occur simultaneously with the steps that owners/operators of affected EGUs would need to undertake if construction of a new natural gas pipeline is needed. The time required to develop and construct natural gas laterals can be broken into three phases: planning and design; permitting and approval; and construction. It is reasonable to assume that the planning and design phase can typically be completed in a matter of months and will often be finalized in less than a year. The time required to complete the permitting and approval phase can vary. Based on a review of recent FERC data, the average time for pipeline projects similar in scope to the projects considered in this TSD is about 1.5 years and would likely not exceed 4 years. The EPA notes that these data may not reflect that pipeline projects may be completed more expeditiously in the presence of a regulatory deadline. Finally, the actual construction could likely be completed in less than 1 year. Based on a sum of these estimates, the EPA believes that 3.5 years is a reasonable timeframe for pipeline projects.

The EPA expects that final emission guidelines will be published in June 2024 and is proposing a State plan submission deadline that is 24 months from publication, which would be June 2026. The proposed compliance date for affected steam generating units is January 1, 2030. The EPA requests comment on whether using a period of 3.5 years after State plan submission is appropriate for establishing a compliance deadline for these emission guidelines. As explained above, the EPA is basing this proposed timeframe on the expectation that some of the initial evaluation and planning steps for both natural gas co-firing and CCS would take place as part of State plan development, *i.e.,* before the State plan submission deadline. The EPA is also requesting comment on potential compliance dates between 1.5 and 5.5 years after State plan submission (*i.e.,* January 1, 2028, to January 1, 2032), including on the feasibility of completing all the steps to implement natural gas co-firing and CCS within a shorter or longer timeframe. To the extent that commenters believe more or less time after State plan submission is more appropriate than the proposed 3.5 years, the EPA requests that commenters provide information supporting the provision of a different compliance date. Additionally, the proposed State plan submission date and proposed compliance date are based on the EPA's anticipation that it will publish final emission guidelines for affected EGUs in June 2024. Should the actual date of publication of the final emission guidelines differ from this target, the EPA will adjust the State plan submission and compliance dates accordingly.

As discussed in section XI.C of this preamble, the EPA is proposing to subcategorize affected existing,

[615] *GHG Mitigation Measures for Steam Generating Units* TSD, chapter 4.7.1. See Table 5 in chapter 4.7.1 for visual representation of the CCS and co-firing project timelines described in this section.

[616] *GHG Mitigation Measures for Steam Generating Units TSD, chapters 3.2.1.4, 3.2.2.3, and 4.7.1.*

frequently used combustion turbines that are covered under these emission guidelines into two subcategories: one subcategory for affected combustion turbine EGUs that adopt the pathway with a standard of performance based on CCS, referred to as the ''CCS subcategory'' and one subcategory for affected combustion turbine EGUs that adopt the pathway with a standard of performance based on hydrogen co-firing, referred to as the ''hydrogen co-fired subcategory.'' For affected combustion turbines in the CCS subcategory, the EPA is proposing a compliance date of January 1, 2035, which is the soonest the Agency believes these sources can comply with standards of performance based on installation and operation of CCS, given the timeframes for planning and construction of carbon capture and CO_2 transport and storage systems along with other demands on the infrastructure and resources needed to implement CCS throughout the power sector and the broader economy. For affected combustion turbines in the hydrogen co-fired subcategory, the EPA is proposing a two-phase standard of performance, with a proposed compliance date for the first phase of January 1, 2032, and for the second phase of January 1, 2038.

For combustion turbine EGUs in the CCS subcategory, the same timeframes and considerations discussed for the planning and construction of CCS for affected coal-fired steam generating units apply. That is, 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 within 5 years. As with affected coal-fired steam generating units, the EPA believes that States and owners or operators can and would take several of the initial steps in the design and planning processes for combustion turbine EGUs as part of State plan development, *i.e.,* prior to the proposed State plan submission deadline in approximately June 2026.

However, as noted in section XI.C of this preamble, the EPA is projecting approximately 12 GW of coal-fired generation will likely retrofit with CCS in order to meet the proposed January 1, 2030, compliance date for affected long-term coal-fired steam generating units. These and other CCS projects that are likely to be occurring in response to the IRA may take up a significant amount of the capacity to plan and build CCS between 2023 and 2030. The EPA anticipates that additional pipeline capacity will be constructed ahead of January 1, 2030, for CO_2 transport as well as for natural gas pipeline laterals that may be needed for affected coal-fired steam generating units that will co-fire with natural gas as a control strategy. Due to these and other overlapping demands on the capacity to design, construct, and operate carbon systems as well as pipeline systems, the EPA is proposing to find that a January 1, 2030, compliance date for affected combustion turbine EGUs in the CCS subcategory, although feasible for an individual unit, would not be the most reasonable deadline for all of the units that would need to install CCS. Therefore, the EPA is proposing to provide a compliance date for affected combustion turbine EGUs in the CCS subcategory that is 5 years after the compliance date for long-term coal-fired steam generating units, or January 1, 2035. The EPA requests comment on its proposed compliance deadline for combustion turbine EGUs in the CCS subcategory, including on whether an earlier or later compliance date would be more reasonable given the time needed to analyze, design, and construct carbon capture and CO_2 transport and storage systems and the overlapping timeframes for installation of CCS on EGUs under the proposed CAA section 111(b) standards of performance for new combustion turbines and on existing coal-fired steam generating units under these proposed emission guidelines.

For affected combustion turbine EGUs in the hydrogen co-fired subcategory, the EPA is proposing a compliance deadline for the first phase of January 1, 2032. As discussed in sections VII.F.3.c.v and vi of this preamble, currently the vast majority of hydrogen is not low-GHG hydrogen. Midstream infrastructure limitations and the adequacy and availability of hydrogen storage facilities currently present obstacles and increase prices for delivered low-GHG hydrogen. However, given the growth in the hydrogen sector and Federal funding for DOE's H2Hubs, which will explicitly explore and incentivize hydrogen distribution, the EPA believes hydrogen distribution and storage infrastructure will not present a barrier to access for new combustion turbines opting to co-fire 30 percent hydrogen by volume in 2032. Legislative actions including the IIJA and IRA, utility initiatives, and industrial sector production and infrastructure projects indicate that sufficient low-GHG hydrogen and sufficient distribution infrastructure can reasonably be expected to be available by this time. On this basis, the EPA is proposing that compliance with the first phase of the standard, which is based on an affected EGU co-firing 30 percent (by volume) low-GHG hydrogen, will commence on January 1, 2032.

The proposed compliance date of January 1, 2038, for the second phase of the standard of performance for combustion turbine EGUs in the hydrogen co-fired subcategory, which is based on a proposed BSER of 96 percent (by volume) co-firing low-GHG hydrogen, is also based on an assessment of when sufficient quantities of such hydrogen will be available, as well as when turbine vendors are anticipated to have the equipment necessary for higher percentages of hydrogen co-firing available. As discussed in section VII.F.3 of this preamble, the EPA expects that based on technology advances, growing demand for low-GHG hydrogen, and the hydrogen production tax credits available under IRC 45V(b)(2), there will be continued expansion of the hydrogen production and transmission network between 2032 and 2038. The EPA also notes that, based on the current ages of the existing combustion turbine fleet, the number of units that would be expected to meet their standards of performance in 2038 by co-firing 96 percent hydrogen (by volume) is likely to decline. Therefore, the EPA believes it is reasonable to expect that there will be sufficient low-GHG hydrogen in 2038 to provide the quantities needed for both new and affected existing combustion turbines in the hydrogen co-fired subcategory to meet their applicable standards of performance. The EPA requests comment on this assessment, as well as on whether compliance dates other that January 1, 2032, and January 1, 2038, would be more reasonable for the first and second phases of the standards for affected units in the hydrogen co-fired subcategory, and why.

C. 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 best system of emission reduction 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.[617] The level of emission performance required under CAA section 111 is reflected in the EPA's presumptive standards of performance.

States use the EPA's presumptive standards of performance as the basis for establishing requirements for affected sources in their State plans. In order for the EPA to find a State plan ''satisfactory,'' that plan must address each affected source within the State and achieve the level of emission performance that would result if each affected source was achieving its presumptive standard of performance, after accounting for any application of RULOF.[618] That is, while States have the discretion to establish the applicable standards of performance for affected sources in their State plans, the structure and purpose of CAA section 111 require that those plans achieve equivalent stringency as applying the EPA's presumptive standards of performance to each of those sources (again, after accounting for any application of RULOF).

The EPA's December 2022 proposed revisions to the CAA section 111 implementing regulations (40 CFR part 60, subpart Ba) would provide that States are permitted, in appropriate circumstances, to adopt compliance measures that allow their sources to meet their standards of performance in the aggregate.[619] As with the establishment of standards of performance for affected sources, CAA section 111 requires that State plans that include such flexibilities for complying with standards of performance demonstrate equivalent stringency as would be achieved if each affected source was achieving its standard of performance.

The requirement that State plans achieve equivalent stringency to the EPA's BSER and degree of emission limitation is borne out of 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 purpose by requiring source categories that cause or contribute to dangerous air pollution to operate more cleanly. Unlike the Clean Air Act'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.

In the course of complying with a rate-based standard of performance under a State plan, an affected source may take an action that removes it from the source category, *e.g.,* by permanently ceasing operations. In this case, the source is no longer subject to the emission guidelines. An affected source may also choose to change its operating characteristics in a way that impacts its overall emissions, *e.g.,* by changing its utilization; however, the source is still required to meet its rate-based standard. In either instance, the changes to one affected source do not implicate the obligations of other affected sources. Although such changes may reduce emissions from the source category, they do not absolve the remaining affected EGUs from the statutory obligation to improve their emission performance consistent with the level that the EPA has determined is achievable through application of the BSER. This fundamental statutory requirement applies regardless of whether a standard of performance is expressed or implemented as a rate- or mass-based emission limitation, or whether standards of performance are achieved on a source-specific or aggregate basis.

In sum, consistent with the respective roles of the EPA and States under CAA section 111, States have discretion to establish standards of performance for affected sources in their State plans, and to provide flexibilities for affected sources to use in complying with those standards. However, State plans must demonstrate that they ultimately provide for equivalent stringency as would be achieved if each affected source was achieving the applicable presumptive standard of performance, after accounting for any application of RULOF.

D. Establishing Standards of Performance

CAA section 111(d)(1)(A) provides that ''each State shall submit to the Administrator a plan which establishes standards of performance for any existing source''; that plan must also ''provide[ ] for the implementation and enforcement of such standards of performance.'' That is, States must use the BSER and stringency in the EPA's emission guidelines to establish standards of performance for each existing affected EGU through a State plan.

To assist States in developing State plans that achieve the level of stringency required by the statute, it has been the EPA's longstanding practice to provide presumptively approvable standards of performance or a methodology for establishing such standards. For the purpose of these emission guidelines, the EPA is proposing a methodology for States to use in establishing presumptively approvable standards of performance for affected existing EGUs. Per CAA section 111(a)(1), the basis of this methodology is the degree of emission limitation the EPA has determined is achievable through application of the BSER to each subcategory. The EPA anticipates and intends for most States to apply the presumptive standards of performance to affected EGUs.

Additionally, CAA section 111(d)(1)(B) permits States to take into consideration a particular affected EGU's RULOF when applying a standard of performance to that source. The EPA's proposed revisions to the CAA section 111 implementing regulations at 40 CFR part 60, subpart Ba provide that a State would be able to apply a less stringent standard of performance to an affected EGU when the State can demonstrate that the source cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA. Proposed subpart Ba describes the conditions that would warrant application of a less stringent RULOF standard under these emission guidelines and how a RULOF standard

[617] *See, e.g., West Virginia* v. *EPA,* 142 S. Ct. 2587, 2607 (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).

[618] As explained in section XI.D.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 apply the BSER to 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.

[619] 87 FR 79176, 79207–08 (December 23, 2015).

would be determined. Further detail about how the EPA proposes to implement the RULOF provision in the context of this rulemaking is provided in section XII.D.2 of this preamble.

States also have the authority to apply standards of performance to affected EGUs that are more stringent than the EPA's presumptively approvable standards of performance.[620]

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. Under this proposal, each subcategory with a proposed BSER and degree of emission limitation would have a corresponding methodology for establishing presumptively approvable standards of performance (also referred to as ''presumptive standards of performance'' or ''presumptive standards'').

A State, when establishing standards of performance for affected EGUs in its plan, would identify each affected EGU in the State and specify into which subcategory each EGU falls. The EPA is proposing that the State would then use the corresponding methodology for the given subcategory to calculate and apply the presumptively approvable standard of performance for each affected EGU.

States also have the authority to deviate from the methodology for presumptively approvable standards, in order to apply a more stringent standard of performance through increasing the degree of emission limitation beyond what the EPA has determined to be achievable for units as a general matter (*e.g.,* a State decides that an EGU in the medium-term coal-fired subcategory should co-fire 50 percent natural gas instead of 40 percent). Deviations to increase stringency do not trigger use of the RULOF mechanism, which requires States to demonstrate that an affected EGU cannot reasonably apply the BSER to achieve the degree of emission limitation determination by the EPA.[621] The EPA proposes to presume that standards of performance that are more stringent than the EPA's presumptive standards are ''satisfactory'' for the purposes of CAA section 111(d).

a. Establishing Baseline Emission Performance for Presumptive Standards

For each subcategory, the proposed methodology to calculate a standard of performance entails establishing a baseline of CO_2 emissions and corresponding electricity generation for an affected EGU and then applying the degree of emission limitation achievable through the application of the BSER (as established in section X.D and XI.C of this preamble). The methodology for establishing baseline emission performance for an affected EGU is identical in each of the subcategories but will result in a value that is unique to each affected EGU. To establish baseline emission performance for an affected EGU, the EPA is proposing 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 years immediately prior to the date the final rule is published in the **Federal Register**. This proposed 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 proposing 8 quarters of data as that corresponds to quarterly reporting according to 40 CFR part 75. Functionally, the EPA expects States to utilize the most representative 8-quarter period of data from the 5 years immediately preceding the date the final rule is published in the **Federal Register**. For the 8 quarters of data, the EPA is proposing that a State would divide the total CO_2 emissions (in the form of pounds) over that continuous time period by the total gross electricity generation (in the form of MWh) over that same time period to calculate baseline CO_2 emission performance in lb CO_2 per MWh. As an example, a State establishing baseline emission performance in the year 2023 would start by evaluating the CO_2 emissions and electricity generation data for each of its affected EGUs for 2018 through 2022 and choosing, for each affected EGU, a continuous 8-quarter period that it deems to be the best 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 proposing to require 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 a few 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 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 of using total CO_2 mass emissions and total electric generation over an 8-quarter period also aligns with the reporting and compliance requirements. The EPA is proposing that compliance would be demonstrated annually 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 for an affected EGU during the compliance year, which is consistent with the expression of the degree of emission limitation proposed for each subcategory in sections X.D.4, X.E.2, and XI.C. The EPA believes that using total mass CO_2 emissions and total electric generation 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, this approach, by not sorting or filtering the data, eliminates any need for discretion in assessing whether the data is appropriate to use.

The EPA is soliciting comment on the proposed baseline-setting approach and specifically on the applicability of such an approach for each of the different subcategories. The EPA is proposing a continuous 8-quarter period to better average out operating variability but

[620] 40 CFR 60.24a(f). The EPA has proposed to revise this provision to clarify that it has the obligation and authority to review and approve state plans that contain the more stringent requirements. 87 FR 79176, 79204 (December 23, 2022).

[621] 87 FR 79176, 79199 (December 23, 2022).

solicits comment on whether a different time period would be more appropriate for assessing baseline emission performance, as well as on the 5-year window from which the period for baseline emission performance is chosen. The EPA also solicits comment on the use of total mass CO_2 emissions and total electric generation over a consecutive 8-quarter time period as representative and on whether the EPA's proposed approach is appropriate.

The EPA believes that using the proposed 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 accommodate unit-specific circumstances, States retain the ability to deviate from the methodologies the EPA is proposing for establishing baselines of emission performance for affected EGUs. 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. The EPA is proposing that States wishing to vary the baseline calculation for an affected EGU based on anticipated changes in operation, when those changes result in a less stringent standard of performance, must use the RULOF mechanism, which is designed to address such contingencies.

b. Presumptive Standards for Steam Generating Units

As described in section X.C of this preamble, the EPA is proposing to first subcategorize affected existing steam generating units by fuel type: coal-fired and oil- or natural gas-fired steam generating units. The EPA is proposing further subcategorization into four subcategories for coal-fired steam generating units and seven subcategories for oil- and natural gas-fired steam generating units. As explained in section X.C.3, the EPA is proposing that an affected coal-fired steam generating unit's operating horizon determines the applicable subcategory in three of the four subcategories; in the case of the near-term subcategory, the operating horizon and load level establish applicability.

The EPA notes that, as explained in section X.C.3 of this preamble, where the owners or operators of affected coal-fired steam-generating units have elected to commit to permanently cease operation (and, in the case of near-term operating horizon units, to limit their capacity factor) and have also elected to make any such commitments federally enforceable through inclusion in a State plan, a State may rely on such commitments to subcategorize coal-fired steam generating units under these emission guidelines. To be included in a State plan a commitment to cease operations or to limit capacity factor must be enforceable by the State, whether through State rule, agreed order, permit, or other legal instrument.[622] Upon EPA approval of the State plan, that commitment will become federally enforceable.

For affected oil- and natural gas-fired steam generating units, subcategories are defined by load level and the type of fuel fired, as well as locality (*i.e.,* continental and non-continental U.S.). There are four subcategories for oil-fired steam generating units based on different combinations of load level (base load, intermediate load, and low load) and locality, and three subcategories for natural gas-fired steam generating units based on load level (base load, intermediate, and low).

i. Long-Term Coal-Fired Steam Generating Units

This section describes the EPA's proposed methodology for establishing presumptively approvable standards of performance for long-term coal-fired steam generating units. Affected coal-fired steam generating units that have either (1) Elected to commit to permanently cease operations on January 1, 2040, or later, or (2) that have not elected to commit to permanently cease operations as part of the State's plan submission, fall within this subcategory and have a proposed BSER of CCS with 90 percent capture and a proposed 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 gross basis over an extended period of time. The EPA is proposing that where States use the methodology described here to establish standards of performance for an affected EGU in this subcategory, those established standards would be presumptively approvable when included in a State plan submission. In section X of this preamble, for the long-term coal-fired subcategory, the EPA is soliciting comment on a capture rate of 90 to 95 percent and a degree of emission limitation defined by a reduction in emission rate on a gross basis from 75 to 90 percent.

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 above); and applying the level of stringency, 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 level of stringency of an 88.4 percent reduction in CO_2 emission rate (see section X.D.4.a of this preamble) 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 per MWh, it will have a presumptively approvable standard of performance of 232 lbs per MWh (2,000 lbs per MWh multiplied by 0.116).

The EPA is also proposing that affected coal-fired EGUs in the long-term subcategory comply with federally enforceable increments of progress, which are described in section XII.D.3.a of this preamble.

The EPA solicits comments on this proposed methodology for calculating presumptively approvable standards of performance for long-term coal-fired steam generating units.

ii. Medium-Term Coal-Fired Steam Generating Units

This section describes the EPA's proposed methodology for establishing presumptively approvable standards of performance for medium-term coal-fired steam generating units. Affected coal-fired steam generating units that have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2040, have a proposed BSER of 40 percent co-firing of natural gas. The EPA is proposing 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 earlier in this preamble); and applying the level of emission reduction

[622] 40 CFR 60.26a.

stringency, 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 CO_2 emissions (see section X.D.4.b of this preamble) 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 per MWh, it will have a presumptively approvable standard of performance of 1,680 lbs per MWh (2,000 lbs per MWh multiplied by 0.84). In section X of this preamble, for the medium-term coal-fired subcategory, the EPA is soliciting comment on a natural gas co-firing level of 30 to 50 percent and a degree of emission limitation from 12 to 20 percent.

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 proposing 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 12 percent (*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. However, the EPA solicits comment on whether the adjustment of a standard of performance based on preexisting levels of natural gas co-firing should be done through the baseline. To adjust the baseline to account for preexisting natural gas co-firing, the State would need to calculate a baseline of emission performance for an EGU that removes the mass emissions and electric generation that are attributable to the natural gas portion of the fuel. With this adjusted baseline that removes the natural gas-fired portion, the presumptive standard of performance would be calculated by multiplying the adjusted baseline by the degree of emission limitation factor that reflects 40 percent co-firing. The EPA is not proposing this methodology, because parsing the attributable emissions and electric generation associated with natural gas co-firing from the attributable emissions and electric generation associated with coal-fired generation requires manipulation of the emissions and electric generation data. However, the EPA solicits comment on whether baseline adjustment is more appropriate and also why that may be so.

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, to qualify for inclusion in the subcategory an affected coal-fired steam generating unit must have elected to commit to permanently cease operations prior to January 1, 2040. If a State decides to rely on such a commitment to place an affected EGU into the medium-term coal-fired subcategory by making it an enforceable element of its State plan, the commitment to cease operations will become federally enforceable upon EPA approval of the plan.

The EPA is proposing that affected coal-fired EGUs that elect to commit to dates to permanently cease operations for subcategory applicability, including EGUs in the medium-term coal-fired subcategory, have corresponding federally enforceable milestones with which they must comply. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with their State plan and commitments to dates to permanently cease operations. These milestones are described in detail in section XII.D.3.b of this preamble. Affected EGUs in this subcategory would also be required to comply with the federally enforceable increments of progress described in section XII.D.3.a of this preamble.

The EPA solicits comment on the proposed methodology for calculating presumptively approvable standards of performance for medium-term coal-fired steam generating units, including on the proposed approach for adjusting a presumptively approvable standard of performance to accommodate preexisting natural gas co-firing.

iii. Imminent-Term Coal-Fired Steam Generating Units

This section describes the EPA's proposed methodology for establishing presumptively approvable standards of performance for imminent-term coal-fired steam generating units. Affected coal-fired steam generating units that elect to commit to permanently cease operations before January 1, 2032, have a proposed BSER of routine methods of operation and maintenance. Therefore, the proposed presumptively approvable standard of performance is not to exceed the baseline emission performance of the affected EGU (as described in section XII.D.1.a of this preamble).

Unlike the proposed standards of performance for the long-term and medium-term coal-fired steam generating units, establishing a standard of performance for an affected EGU in the imminent-term subcategory consists of just one step. The EPA is proposing that where States use the methodology described in section XII.D.1.a of this preamble to establish the baseline level of emission performance for an affected EGU, the emission rate described by that baseline would constitute the presumptively approvable standard of performance. This standard of performance reflects that the proposed BSER for these affected EGUs is routine methods of operation and maintenance and a degree of emission limitation equivalent to no increase in emission rate from the baseline level of emission performance. This also ensures that the affected EGU will not backslide in its emission performance.

Although the EPA believes that the baseline performance level adequately accounts for variability in annual emission rate, the EPA is also soliciting comment on a methodology for a presumptive standard above the baseline emission performance. For the imminent-term coal-fired subcategory, the EPA is soliciting comment on a presumptive standard 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.

Because the EPA is soliciting comment on a potential BSER for this subcategory based on low levels of natural gas co-firing, as described in section X.D.3.b.ii, comment is also being solicited on the presumptively approvable standards for that potential BSER. The BSER is based on the maximum hourly heat input of natural gas fired in the unit (MMBtu/hr) relative to the maximum hourly heat input the unit is capable of (*i.e.,* the nameplate capacity on an MMBtu/hr basis). The EPA is soliciting comment on the baseline natural gas co-firing level being determined from the 5 years of data preceding the publication of the final rule, or based on engineering limitations (*i.e.,* extent of startup guns or size of pipeline to unit). That percent of heat input results in percent reductions from the emission performance baseline equivalent to the percent of heat input times 0.4. Adjustments relative to current co-firing levels may be accounted for in a manner consistent with section XII.D.1.b.ii. Alternatively, the EPA is soliciting comment on a degree of emission limitation on a fuel heat input basis. For a potential BSER of low levels of natural gas co-firing, the EPA is therefore also soliciting comment on a presumptively approvable standard defined on a heat input basis.

The standard of performance for the imminent-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, to qualify for inclusion in the subcategory an affected coal-fired EGU must have elected to commit to permanently cease operations prior to January 1, 2032. If a State decides to rely on such a commitment to place an affected EGU into the imminent-term coal-fired subcategory by making it an enforceable element of its State plan, the commitment to cease operations will become federally enforceable upon EPA approval of the plan.

The EPA is also proposing that affected coal-fired steam generating units that have elected to commit to dates to permanently cease operations for subcategory applicability, including EGUs in the imminent-term coal-fired subcategory, have corresponding federally enforceable milestones with which they must comply. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with these dates in their State plan. These milestones are described in detail in section XII.D.3.b of this preamble.

The EPA solicits comment on the proposed methodology for establishing presumptively approvable standards of performance for imminent-term coal-fired steam generating units.

iv. Near-Term Coal-Fired Steam Generating Units

Similar to the proposed approach for establishing presumptively approvable standards of performance for affected EGUs in the imminent-term coal-fired subcategory, the EPA is proposing that affected EGUs in the near-term coal-fired subcategory have a presumptively approvable standard of performance based on the baseline emission performance of the affected EGU (as described in section XII.D.1.a of this preamble). The near-term subcategory includes affected coal-fired steam generating units that have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2035, and that have elected to adopt an annual capacity factor limitation of 20 percent.

The EPA is proposing that where States use the methodology described in section XII.D.1.a of this preamble to establish the baseline level of emission performance for an affected EGU, the emission rate described by that baseline would constitute the presumptively approvable standard of performance. This standard of performance reflects the proposed BSER of routine methods of operation and maintenance and a degree of emission limitation equivalent to no increase in emission rate. This also ensures that the affected EGU will not backslide in its emission performance.

For the near-term coal-fired subcategory, the EPA is soliciting comment on a presumptive standard 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.

Because the EPA is soliciting comment on a potential BSER for this subcategory based on low levels of natural gas co-firing, as described in section X.D.3.b.ii, comment is also being solicited on the presumptively approvable standards for that potential BSER. The BSER is based on the maximum hourly heat input of natural gas fired in the unit (MMBtu/hr) relative to the maximum hourly heat input the unit is capable of (*i.e.,* the nameplate capacity on an MMBtu/hr basis). The EPA is soliciting comment on the baseline natural gas co-firing level being determined from the 5 years of data preceding the publication of the final rule, or based on engineering limitations (*i.e.,* extent of startup guns or size of pipeline to unit). That percent of heat input results in percent reductions from the emission performance baseline equivalent to the percent of heat input times 0.4. Adjustments relative to current co-firing levels may be accounted for in a manner consistent with section XII.D.1.b.ii. Alternatively, the EPA is soliciting comment on a degree of emission limitation on a fuel heat input basis. For a potential BSER of low levels of natural gas co-firing, the EPA is therefore also soliciting comment on a presumptively approvable standard defined on a heat input basis.

The standard of performance for the near-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, to qualify for inclusion in the subcategory an affected coal-fired EGU must have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2035, and must have elected to adopt an annual capacity factor limitation of 20 percent. If a State decides to rely on such commitments to place an affected EGU into the near-term coal-fired subcategory by making them enforceable elements of its State plan, the commitments to cease operations and to limit its capacity factor will become federally enforceable upon EPA approval of the plan.

The EPA is also proposing that affected coal-fired EGUs that have elected to commit to dates to permanently cease operations for subcategory applicability, including EGUs in the near-term coal-fired subcategory, have corresponding federally enforceable milestones with which they must comply. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with these dates in their State plan. These milestones are described in detail in section XII.D.3.b of this preamble.

The EPA solicits comment on the proposed methodology for establishing presumptively approvable standards of performance for near-term coal-fired steam generating units.

v. Natural Gas-Fired Steam Generating Units and Continental Oil-Fired Steam Generating Units

This section describes the EPA's proposed methodology for presumptively approvable standards of performance for affected natural gas-fired and continental 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 continental oil-fired steam generating units, and base load continental oil-fired steam generating units. It does not address non-continental intermediate oil-fired and non-continental base load oil-fired steam generating units, which are described in section XII.D.1.b.vi of this preamble. The proposed definitions of these subcategories are discussed in section X.C.2 of this preamble. The proposed 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.

Unlike the approach to establishing presumptive standards of performance for coal-fired EGUs in these proposed emission guidelines, the EPA is proposing presumptive standards of performance for affected natural gas-fired and continental oil-fired steam generating units in lieu of methodologies that States would use to establish presumptive standards of performance. This is largely because 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 X.E of this preamble and detailed in the *Natural Gas- and Oil-fired Steam Generating Unit* TSD, allows for the identification of a generally applicable standard of performance.

However, for natural gas- or oil-fired steam generating units with low annual capacity factors, annual emission rates can be high (greater than 2,500 lb CO_2/MWh-gross) and can vary considerably across units and from year to year. Despite their relatively high emission rates, though, overall emissions from these units are low. Based on these considerations, the EPA is not proposing a BSER or that States establish standards of performance for these units at this time. However, as noted above, the EPA is soliciting comment on determining a BSER of uniform fuels for these units. In addition, the EPA is soliciting comment on a presumptive standard of performance for these units based on heat input. Specifically, the EPA is soliciting comment on a range of presumptive standards of performance from 120 to 130 lb CO_2/MMBtu for low load natural gas-fired steam generating units, and from 160 to 170 lb CO_2/MMBtu for low load oil-fired steam generating units.

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 1,500 lb CO_2/MWh-gross for about 90 percent of the units. Therefore, the EPA is proposing the presumptive standard of performance of an annual calendar-year emission rate of 1,500 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 1,300 lb CO_2/MWh-gross for about 80 percent of units. Therefore, the EPA is proposing the presumptive standard of performance of an annual calendar-year emission rate of 1,300 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 Mercury and Air Toxics Standards rule (MATS) (40 CFR 63, subpart UUUUU). If oil-fired units operated at higher annual capacities, 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 proposing the same presumptive standards of performance for oil-fired steam generating units as for natural gas-fired units, noted above.

The EPA is also taking comment on a range of presumptive standards of performance for natural gas- and oil-fired steam generating units. Specifically, the EPA is soliciting comment on standards between (1) 1,400 and 1,600 lb CO_2/MWh-gross for intermediate load natural gas-fired units, (2) 1,250 and 1,400 lb CO_2/MWh-gross for base load natural gas-fired units, (3) 1,400 and 2,000 lb CO_2/MWh-gross for intermediate load oil-fired units, and (4) 1,250 and 1,800 lb CO_2/MWh-gross for base load oil-fired units. The upper end of the ranges for oil-fired units is higher because of the limited data available for oil-fired units that operate at those annual capacity factors.

vi. Non-Continental Oil-Fired Steam Generating Units

The EPA is proposing that for affected EGUs in the non-continental intermediate oil-fired and non-continental base load oil-fired subcategory, a presumptively approvable standard of performance would be based on baseline emission performance, consistent with the EPA's proposed BSER determination of routine methods of operation and maintenance and the proposed degree of emission limitation of no increase in emission rate. The EPA is proposing that where States use the methodology described in section XII.D.1.a of the preamble to establish unit-specific baseline levels of emission performance for affected EGUs in this subcategory, those emission rates would constitute presumptively approvable standards of performance when included in a State plan submission. This standard of performance would ensure no increase in the unit-specific emission rate from the baseline level of emission performance.

For the intermediate and base load non-continental oil-fired subcategory, the EPA is soliciting comment on a presumptive standard 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.

The EPA solicits comment on the proposed methodology for establishing presumptively approvable standards of performance for non-continental oil-fired steam generating units in the intermediate and base load subcategories.

c. Presumptive Standards for Combustion Turbines

As described in section XI.C, the EPA is proposing to define affected existing combustion turbines under these emission guidelines as units with a capacity greater than 300 MW and an annual capacity factor of greater than 50 percent. Within this set of units, the EPA is proposing two subcategories based on the type of fuel used: existing combustion turbines that adopt the pathway with a standard of performance based on CCS, referred to as the ''CCS subcategory'' and existing combustion turbines that adopt the pathway with a standard of performance based on hydrogen co-firing, referred to as the ''hydrogen co-fired subcategory.'' States, in their State plan submissions, would be required to assign existing combustion turbine EGUs with capacities greater than 300 MW and the ability to operate at an annual capacity factor of greater than 50 percent to one subcategory or the other.[623] States would then be required to include in their plans the presumptive standard of performance corresponding to the appropriate subcategory for each affected existing combustion turbine EGU. As discussed in section XII.D.2 of this preamble, States, in applying a standard of performance to a particular affected existing combustion turbine EGU, also have discretion to consider that EGU's remaining useful life and other factors.

However, the EPA anticipates that some existing combustion turbine EGUs that are greater than 300 MW do not intend to operate at an annual capacity factor of greater than 50 percent starting in 2032 (the first proposed compliance date for affected existing combustion turbine EGUs under these emission guidelines). Such an EGU may elect to commit to an enforceable annual capacity factor limitation of less than or equal to 50 percent. If a State elects to include such an enforceable commitment in its State plan, the State would not be required to have a standard of performance for that particular combustion turbine EGU in its plan. Otherwise, each affected existing combustion turbine that is greater than 300 MW and that has the ability to operate at an annual capacity factor of greater than 50 percent must have a subcategory designation and standard of performance in the State plan.

The EPA is proposing that States may structure the requirements for affected combustion turbine EGUs in their State plans so that the applicable standard of performance must be met for years in which the unit operates above the 50 percent annual capacity factor threshold. States and the owners or operators of affected EGUs that have such contingent standards of performance would be required to ensure that an affected EGU has complied with its standard of performance for each calendar year in which it has operated at an annual capacity factor of greater than 50 percent. The EPA expects that if the owner or operator of an affected combustion turbine EGU that has a standard of performance believes there is a chance the EGU will operate at an annual capacity factor of greater than 50 percent in the upcoming compliance period, it will plan to meet that standard. Given this practical reality, the EPA is taking comment on whether it should require that once an affected existing combustion turbine EGU has exceeded the 50 percent annual capacity factor threshold and triggered application of its standard of performance for a given compliance period, that EGU must continue to meet its standard in subsequent compliance periods.

i. Carbon Capture and Storage Existing Combustion Turbine Generating Units

This section describes the EPA's proposed methodology for establishing presumptively approvable standards of performance for existing combustion turbine EGUs that adopt the pathway with a standard of performance based on CCS. Affected EGUs that are assigned to this subcategory have a proposed BSER of CCS with 90 percent capture and a proposed 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 turbine but before the capture equipment) over an extended period of time and an 89 percent reduction in emission rate on a gross basis over an extended period of time. The EPA is proposing that where States use the methodology described here to establish standards of performance for an affected EGU in this subcategory, those established standards would be presumptively approvable when included in a State plan submission.

Establishing a standard of performance for an affected combustion turbine EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described above); and applying the level of stringency, 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 level of stringency of an 89 percent reduction in CO_2 emission rate (see section XI.C of this preamble) compared to the baseline level of emission performance. Using the complement of 89 percent (*i.e.,* 11 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance. For example, if a combustion turbine EGU in this subcategory has a baseline level of emission performance of 1,000 lbs per MWh, it will have a presumptively approvable standard of performance of 110 lbs per MWh (1,000 lbs per MWh multiplied by 0.11).

The EPA is also proposing that affected combustion turbines in this subcategory comply with federally enforceable increments of progress, which are described in section XII.D.3.a of this preamble.

The EPA solicits comments on this proposed methodology for calculating presumptively approvable standards of performance for existing combustion turbines in the CCS subcategory.

ii. Hydrogen Co-Fired Existing Combustion Turbine Generating Units

This section describes the EPA's proposed methodology for establishing presumptively approvable standards of performance for existing combustion turbines that adopt the pathway with a standard of performance based on hydrogen co-firing. Affected combustion turbine EGUs in this subcategory have a proposed BSER of hydrogen co-firing with two phases of stringency. In the first phase, affected EGUs in this subcategory co-fire hydrogen at a level of 30 percent by volume with a proposed degree of emission limitation of 12 percent reduction in emission rate on a gross basis over an extended period of time. In the second phase, affected EGUs in this subcategory co-fire hydrogen at a level of 96 percent by volume with a proposed degree of emission limitation of 88.4 percent reduction in emission rate on a gross basis over an extended period of time. As described in section XII.B, compliance with the first phase commences on January 1, 2032, and compliance with the second phase commences on January 1, 2038. The EPA is proposing that where States use the methodology described here to establish standards of performance for 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 three steps: first, establishing a source-specific level of baseline emission performance (as described earlier in this preamble); and second, applying the level of emission reduction stringency for the first phase, based on the application of the first phase BSER, to that level of baseline emission performance; and third, applying the level of emission reduction stringency for the second phase, based on the application of the second phase BSER, to that level of baseline emission performance.

Implementation of hydrogen co-firing at a level of 30 percent by volume translates to a level of stringency of a 12 percent reduction in CO_2 emissions (see

[623] As explained in section XI.D of this preamble, the EPA is soliciting comment on, inter alia, whether to finalize both the CCS and hydrogen co-fired pathways for existing combustion turbines or whether to finalize a BSER determination with a single pathway. If the EPA does not finalize the proposed two-pathway approach, the state plan requirements for existing combustion turbines in this section XII of the preamble will be updated accordingly for the final rule.

section XI.C of this preamble) compared to the baseline level of emission performance. Using the complement of 12 percent (*i.e.,* 88 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 combustion turbine EGU that co-fires 30 percent hydrogen (by volume) has a baseline level of emission performance of 1,000 lbs per MWh, it will have a presumptively approvable standard of performance of 880 lbs per MWh (1,000 lbs per MWh multiplied by 0.88) for the first phase.

Implementation of hydrogen co-firing at a level of 96 percent by volume translates to a level of stringency of an 88.4 percent reduction in CO_2 emissions (see section XI.C of this preamble) 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 the affected EGU. For example, if a combustion turbine EGU that co-fires 96 percent hydrogen (by volume) has a baseline level of emission performance of 1,000 lbs per MWh, it will have a presumptively approvable standard of performance of 116 lbs per MWh (1,000 lbs per MWh multiplied by 0.116) for the second phase.

The EPA is proposing that affected combustion turbine EGUs in this subcategory that meet their standards of performance using hydrogen co-firing must co-fire with low-GHG hydrogen. States must make this an enforceable part of their State plans, as described in further detail in section XII.F.1.b.i.

The EPA is also proposing that affected combustion turbines in this subcategory comply with federally enforceable increments of progress, which are described in section XII.D.3.a of this preamble.

The EPA solicits comment on the proposed methodology for calculating presumptively approvable standards of performance for existing combustion turbine EGUs in the hydrogen co-fired subcategory.

2. Remaining Useful Life and Other Factors

Under CAA section 111(d), the EPA is required to promulgate regulations under which States submit plans applying standards of performance to affected EGUs. 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.[624] 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.D of this preamble, the EPA is providing proposed 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.

While standards of performance must generally reflect the degree of emission limitation achievable through application of the BSER as determined by the EPA, CAA section 111(d)(1) also requires that the EPA regulations permit the States, in applying a standard of performance to a particular designated facility, to ''take into consideration, among other factors, the remaining useful life of the existing sources to which the standard applies.'' The EPA's implementing regulations under 40 CFR 60.24a thus allow a State to consider a particular designated facility's remaining useful life and other factors in applying to that facility a standard of performance that is less stringent than the presumptive level of stringency given in an emission guideline.

In December 2022, the EPA proposed to clarify the existing requirements in subpart Ba governing what a State must demonstrate in order to invoke RULOF and provide a less stringent standard of performance when submitting a State plan.[625] Specifically, the EPA proposed to require the State to demonstrate that a particular facility cannot reasonably achieve the degree of emission limitation achievable through application of the BSER based on one or more of three delineated circumstances, and proposed to clarify those three circumstances. The EPA also proposed additions and further clarifications to the process of invoking RULOF and determining a standard of performance based on RULOF, to ensure that use of the provision does not undermine the overall presumptive level of stringency of the BSER, as well as to provide a clear analytical framework for States and the regulated community as they seek to craft satisfactory plans that the EPA can ultimately approve.[626]

The EPA is not soliciting comment in this rulemaking on the proposed revisions to the RULOF provisions in subpart Ba, which are subject to a separate rulemaking process. As noted in section XII.A of this preamble, the EPA intends to finalize revisions to subpart Ba prior to finalizing these emission guidelines. Those revised RULOF provisions, including any changes made in response to public comments, will apply to these emission guidelines. While the EPA is not taking comment on the proposed provisions of subpart Ba themselves, the EPA is requesting comment on how each of the RULOF provisions that the EPA proposed in December 2022 would be implemented in the context of these particular emission guidelines.

The remainder of this section of the preamble addresses how the requirements associated with RULOF, as the EPA has proposed to revise them, would apply to States and State plans under these emission guidelines. First, it addresses the threshold requirements for considering RULOF and how those requirements would apply to an affected EGU under these emission guidelines. Second, it addresses how, if a State has appropriately invoked RULOF for a particular affected EGU under the previous step, it would be required to determine a source-specific BSER and calculate a standard of performance for that affected EGU. Third, it discusses the proposed requirement for plans that apply less stringent standards of performance pursuant to RULOF to consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the affected EGU. Fourth, this section addresses the proposed provisions for the standard for EPA review of State plans that include RULOF standards of performance. And, finally, it discusses the EPA's proposed interpretation of the Clean Air Act as laid out in the proposed revisions to subpart Ba that the Act allows states to adopt and enforce standards of performance more stringent than required by an applicable emission guideline, and that the EPA has the ability and authority to approve such standards of performance into State plans.

a. Threshold Requirements for Considering RULOF

As discussed earlier in this preamble, CAA section 111(d)(1) expressly

[624] *West Virginia* v. *EPA,* 142 S. Ct. 2587, 2607 (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).

[625] 87 FR 79176, 79196–79206 (December 23, 2022).

[626] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002.

requires the EPA to permit states to consider RULOF when applying a standard of performance to a particular affected EGU. The EPA's proposed revisions to the regulations governing states' use of RULOF would provide a clear analytical framework to ensure that its use to apply less stringent standards of performance for particular sources is consistent across states. The proposed revisions would also ensure that the use of RULOF does not undermine the overall presumptive level of stringency and the emission reduction benefits of an emission guideline, or undermine and render meaningless the EPA's BSER determination. Such a result would be contrary to the overarching purpose of CAA section 111(d), which is generally to achieve meaningful emission reductions from designated facilities, in this case affected EGUs, based on the BSER in order to mitigate pollution that endangers public health and welfare.

To this end, proposed subpart Ba would provide that a State may apply a less stringent standard of performance to a particular facility, taking into consideration remaining useful life and other factors, provided that the State demonstrates with respect to that facility (or class of facilities) that it cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA. Invocation of RULOF would be required to be based on one or more of three circumstances: (1) Unreasonable cost of control resulting from plant age, location, or basic process design, (2) physical impossibility or technical infeasibility of installing necessary control equipment, or (3) other circumstances specific to the facility that are fundamentally different from the information considered in the determination of the BSER in the emission guidelines.[627]

A State wishing to invoke RULOF in order to apply a less stringent standard to a particular affected EGU would be required to demonstrate that there are fundamental differences between that EGU and the EPA's BSER determination, based on consideration of the BSER factors that the EPA considered in its analysis. In determining the BSER and the degree of emission reductions achievable through application of the BSER in these proposed emission guidelines, the EPA considered whether a system of emission reduction is adequately demonstrated for the subcategory based on the physical possibility and technical feasibility of applying that system, 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.[628]

For each subcategory, the EPA evaluated certain metrics related to each of these BSER factors. For example,[629] in evaluating the costs associated with CCS and natural gas co-firing for existing coal-fired steam generating units, the EPA considered both \$/ton CO_2 reduced and increases in levelized costs expressed as dollars per MWh electricity generation. A State wishing to invoke RULOF for a particular affected EGU in the long-term coal-fired subcategory based on unreasonable cost of control would also be required to consider the cost as \$/ton of CO_2 reduced and \$/MWh electricity generated. The State would further have to demonstrate that the costs, as represented by these two metrics, for the particular affected EGU are fundamentally different, *i.e.,* significantly higher, than costs the EPA determines to be reasonable due to that EGU's age, location, or basic process design.

The RULOF provision, currently and as the EPA has proposed to revise it, also allows states to invoke RULOF based on other circumstances specific to an affected EGU. As an illustrative example, a State may wish to invoke RULOF for a medium-term coal-fired steam generating unit that is extremely isolated (*e.g.,* on a small island more than 200 miles offshore) such that it would require construction of an LNG terminal and shipping of LNG by barge to have natural gas available to fire at the unit. In the EPA's evaluation of natural gas co-firing as the potential BSER for medium-term coal-fired steam generating units, the EPA considered the distance and cost of lateral pipeline builds in proposing natural gas co-firing as BSER. If a State can demonstrate that something unique to the source's being on a remote island—something that the EPA did not consider in evaluating the BSER—results in the affected EGU not being able to reasonably achieve the standard of performance, then it may be reasonable to invoke RULOF for that source.

Under the EPA's proposed approach, states would not be able to invoke RULOF based on minor, non-fundamental differences between a particular affected EGU and what the EPA determined was reasonable for the BSER. There could be instances in which an affected EGU may not be able to implement the presumptively approvable standard of performance in accordance with the precise metrics (*e.g.,* at exactly the same \$/ton CO_2 reduced or exactly the same distance from a pipeline connection) of the BSER determination but is able to do so within a reasonable margin. In such instances, it would not be reasonable for a State to apply a less stringent standard of performance.

Many of the factors the EPA considers in its BSER determination, and therefore many of the factors states might consider in determining whether to invoke RULOF for any particular source, are reflected in the cost consideration. As noted previously in this section, the EPA is providing a range of cost evaluations for CCS and natural gas co-firing based on different assumptions regarding amortization period and capacity factor. For example, the EPA is proposing to determine that the cost of CCS for long-term coal-fired steam generating units is reasonable based on the following calculations: for a reference unit with a 12-year amortization period and 50 percent capacity factor the cost is \$14/ton CO_2 reduced or \$12/MWh, and that the average cost for the fleet under the same assumptions is \$8/ton CO_2 or \$7/MWh. For natural gas co-firing for medium-term coal-fired steam generating units, the EPA is proposing to find the following costs are reasonable: for a reference unit with a 50 percent capacity factor and an amortization period ranging from 6 to 10 years, a cost of \$53–\$66/ton CO_2 or \$9–\$12/MWh. The average cost for the fleet under the same assumptions is \$64–\$78/ton CO_2 or \$11–\$14/MWh.

Any costs associated with any BSER for affected EGUs that the EPA determines are reasonable under these emission guidelines cannot be a 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 cannot be a basis for invoking RULOF. Thus, costs that are not fundamentally different from, *e.g.,* \$29/MWh (the cost for installation of wet-FGD on a 300 MW coal-fired steam generating unit, used for cost comparison in section X.D.1.a.ii

[627] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (containing proposed revisions to RULOF provisions at 40 CFR 60.24a(e)–(n)).

[628] The EPA also considered impacts on the energy sector as part of its BSER determinations. However, because this consideration does not apply at the level of a particular affected EGU, it would not be appropriate basis for invoking RULOF.

[629] The examples are only for illustrative purposes and should not be interpreted to represent the difference that must exist to demonstrate a fundamental difference between the EPA's BSER determination and a particular affected EGU's circumstances.

of this preamble and detailed in section VII.F.3.b.iii(B)(5) of this preamble) are not a 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) or that are the same as costs the EPA has determined are unreasonable elsewhere under these emission guidelines would likely represent a valid demonstration of a fundamental difference and could be the basis of invoking RULOF.

Importantly, the costs evaluated in the BSER determination are, in general, for representative, average units or are 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 proposed determination that those average representative values are reasonable is a proposed 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.

Another example of a fundamental difference between the EPA's BSER determination and a particular affected EGU's circumstances could be a difference based on physical impossibility or technical infeasibility. In making BSER determinations, the EPA must find that a system is adequately demonstrated; among other things, this means that the BSER must be technically feasible for the source category. For long-term coal-fired steam generating units and combustion turbine EGUs in the CCS subcategory, the EPA determined that CCS is adequately demonstrated because its components can be and have been applied to the source category and because it is generally geographically available to affected EGUs. However, it may be possible that a particular affected EGU is physically unable to implement CCS due to, *e.g.,* the impossibility of constructing a pipeline or establishing other means for CO_2 transport. If a State can demonstrate that it is physically impossible or technically infeasible for this affected EGU to apply CCS because there are no other options to transport captured CO_2, there is a fundamental difference between the EPA's BSER determination and the circumstances of this particular affected EGU and the State may invoke RULOF.

The EPA has proposed under 40 CFR part 60, subpart Ba that states may invoke RULOF if they can demonstrate that a source cannot apply the BSER to achieve the degree of emission limitation determined by the EPA based on one or more of the three circumstances discussed earlier in this preamble.[630] It thus follows that states would be able to invoke RULOF under these emission guidelines if they can demonstrate that an affected EGU can apply the BSER but cannot achieve the degree of emission limitation that the EPA determined is possible for the source category generally.

However, the EPA has also proposed in subpart Ba [631] that 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. While a State may be able to demonstrate that the source cannot reasonably apply the BSER based on one of the three circumstances, it would be inappropriate to invoke RULOF to apply a less stringent standard of performance because the source can still reasonably achieve the presumptive degree of emission limitation. In this instance, providing a less stringent standard of performance would be inconsistent with the purpose of CAA section 111(d) and these emission guidelines.

States' consideration of the remaining useful life of a particular source for affected coal-fired EGUs, in particular, will also be informed by the structure of the EPA's proposed subcategories, each of which has its own BSER determination under these emission guidelines. Under CAA section 111(d)(1) and the EPA's proposed RULOF provisions, states may consider an affected EGU's remaining useful life in determining whether application of the BSER to achieve the presumptive level of stringency would result in unreasonable cost resulting from plant age.[632] In determining the BSER, the EPA considers costs and, in many instances, specifically considers annualized costs associated with payment of the total capital investment of the technology associated with the BSER. However, plant age can have considerable variability within a source category and the annualized costs can change significantly based on an affected EGU's remaining useful life and associated length of the capital recovery period. Thus, the costs of applying the BSER to an affected EGU with a short remaining life may differ fundamentally from the costs that the EPA found were reasonable in making its BSER determination.

As explained in section X of this preamble, these proposed emission guidelines include BSER determinations and presumptive standards of performance for affected coal-fired EGUs in four subcategories: imminent-term, near-term, medium-term, and long-term. Owing to the basis of these subcategories, the EPA's proposed BSER determinations for each of these subcategories already consider costs amortized consistent with the operating horizons of sources within each subcategory. The EPA therefore does not anticipate that states would be likely to demonstrate the need to invoke RULOF based on a particular coal-fired EGU's remaining useful life, although doing so is not prohibited under these emission guidelines. The proposed requirements for states and affected EGUs invoking RULOF based on remaining useful life are addressed in the next subsection.

Conversely, the proposed subcategories for existing combustion turbines do not consider affected EGUs' operating horizons. The useful life of a combined cycle unit is approximately 25 to 30 years.[633] More than 151 GW of combined cycle units came on-line in the 2000 to 2010 timeframe,[634] meaning that many of these units could potentially be at or nearing the end of their remaining useful lives in the 2035 to 2040 timeframe. If an affected combustion turbine EGU has decided to cease operations and elects to make that cessation enforceable, the period over which controls would be amortized, depending on what that period of time is, may be short enough to invoke RULOF based on unreasonable cost of control.

The EPA is proposing to allow states to use the RULOF mechanism to provide a different compliance deadline for a source that can meet the presumptive standard of performance

[630] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(e)).

[631] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(g)).

[632] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(e)(1)).

[633] *https://sargentlundy.com/wp-content/uploads/2017/05/Combined-Cycle-PowerPlant-LifeAssessment.pdf.*

[634] 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-v6.*

for the applicable subcategory but cannot do so by the final compliance date under these emission guidelines. In such cases, a State may be able to demonstrate that there are ''other circumstances specific to the facility . . . that are fundamentally different from the information considered in the determination of the best system of emission reduction in the emission guidelines'' [635] that make timely compliance impossible. However, given the relatively long lead times and compliance timeframes proposed in these emission guidelines, the EPA anticipates that these circumstances will be rare. Under the proposed revisions to subpart Ba, RULOF demonstrations, including those in support of extending a compliance deadline, would have to be based on information from reliable and adequately documented sources and be applicable to and appropriate for the affected facility.[636]

Additionally, as discussed in section XII.D.1.a of this preamble, the EPA is proposing a methodology for calculating an affected EGU's baseline emissions as part of determining its presumptively approvable standard of performance. The EPA explained that while the proposed methodology should be flexible enough to accommodate most unit-specific circumstances, it may not be appropriate to use recent historical emissions data to represent baseline emission performance when an affected EGU anticipates that its future operating conditions will change significantly. Consistent with the proposed subpart Ba, the EPA is proposing that states wishing to rely on an affected EGU's anticipated change in operating conditions as the basis for using a different methodology to set an emissions baseline would be required to use the RULOF mechanism described in this section of the preamble.

The EPA solicits comment on the application of the RULOF provisions of proposed subpart Ba, both in sum and as individual, segregable pieces, to these emission guidelines. In particular, the EPA requests comment on factual circumstances in which it may or may not be appropriate for states to invoke RULOF for affected EGUs, given the proposed BSER determinations and presumptive standards of performance, and the EPA's proposed ''fundamental difference'' standard in the subpart Ba rulemaking. For the consideration of cost, the EPA requests comment on whether it should provide further guidance or requirements for determining when the costs of a control technology for a particular source are ''fundamentally different'' from the Agency's BSER determination and thus a basis for invoking RULOF. The EPA additionally seeks comment on any source category-specific considerations for invoking RULOF for affected EGUs, including any additional or different requirements that might be necessary to ensure that use of RULOF does not undermine the presumptive stringency of these emission guidelines.

b. Calculation of a Standard That Accounts for RULOF

Subpart Ba, both the presently applicable requirements and as the EPA has proposed to revise them, provides that, if a State has demonstrated that accounting for RULOF is appropriate for a particular affected EGU, the State may then apply a less stringent standard to that EGU. The EPA's proposed revisions to subpart Ba would require that, in doing so, the State must determine a source-specific BSER by identifying all the systems of emission reduction available for the source and evaluating each system using the same factors and evaluation metrics that the EPA considered in determining the BSER for the applicable subcategory.[637] As part of determining source-specific BSER, the State would also have to determine the degree of emission limitation that can be achieved by applying this source-specific BSER to the particular source. The State would then calculate and apply the standard of performance that reflects this degree of emission limitation.[638]

Consistent with these proposed requirements in subpart Ba, the EPA is proposing that states invoking RULOF would be required to evaluate certain controls as appropriate for subcategories of affected EGUs. The EPA believes these proposed requirements are necessary to ensure that states reasonably consider the controls that may qualify as the best system of emission reduction. Additionally, the EPA is proposing to provide the order in which states must evaluate controls. A list of controls, ordered from more to less stringent, can provide useful streamlining as states may reasonably choose to conduct a less in-depth evaluation of controls further down the list if they determine a more stringent control is the best system of emission reduction for a particular source. The EPA also believes that providing a list of controls for evaluation will provide states with clarity and certainty about what the Agency will find is a satisfactory source-specific BSER analysis pursuant to the RULOF mechanism. However, the EPA is also requesting comment on whether to provide lists of controls to be evaluated in a source-specific BSER analysis as a presumptively approvable approach, as opposed to requirements. Regardless of how the EPA finalizes the approach to controls for source-specific analyses, states would retain discretion to evaluate additional types of controls as part of a source-specific BSER determination for sources pursuant to RULOF.

The EPA is proposing to require states invoking RULOF for affected coal-fired EGUs in the long-term subcategory to evaluate natural gas co-firing as a potential source-specific BSER. Additionally, if an EGU in the long-term subcategory can implement CCS but cannot achieve the degree of emission limitation prescribed by the presumptive standard of performance, the EPA is proposing that the State evaluate CCS with a source-specific degree of emission limitation as a potential BSER. The EPA is also proposing that states invoking RULOF for affected long-term and medium-term coal-fired EGUs must evaluate different levels of natural gas co-firing. For example, for a source in the medium-term subcategory that cannot reasonably co-fire 40 percent natural gas, the State must then evaluate lower levels of natural gas co-firing unless it has demonstrated that natural gas co-firing at any level is physically impossible or technically infeasible at the source. Similarly, if a State invoking RULOF for an affected EGU in the long-term subcategory demonstrates that the EGU cannot co-fire with natural gas at 40 percent, the EPA is proposing that the State must then evaluate lower levels of co-firing as potential BSERs for the source, unless the State can demonstrate that it is physically impossible or technically infeasible for the source to co-fire natural gas. States may also consider additional potential source-specific BSERs for affected EGUs in either subcategory.

For states invoking RULOF for affected existing combustion turbine EGUs, the EPA is similarly proposing a requirement to evaluate certain control

[635] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(e)(3)).

[636] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(j)).

[637] To the extent that a state seeks to apply RULOF to a class of affected EGUs that the state can demonstrate are similarly situated in all meaningful ways, the EPA proposes to permit the state to conduct an aggregate analysis of the BSER factors for the entire class of EGUs for which RULOF has been invoked.

[638] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(f)).

strategies as part of a source-specific BSER analysis. As a preliminary step, for sources in either the CCS combustion turbine subcategory or the hydrogen co-fired combustion turbine subcategory, the EPA is proposing that a State would first have to demonstrate why the affected EGU cannot reasonably participate in the other subcategory and meet that other subcategory's presumptive standard of performance. If a unit can reasonably comply with the presumptive standard of performance for the alternate source category, it must do so.

For combustion turbines in the CCS subcategory that cannot reasonably comply with the presumptive standards of performance for either that subcategory or the hydrogen co-fired subcategory, the EPA is proposing that, unless a State has demonstrated that it is physically impossible or technically infeasible for a unit to implement CCS, the State must evaluate CCS with lower rates of carbon capture as a potential BSER. If CCS with lower rates of capture is not the BSER, the State would then be required to consider comprehensive turbine upgrades, and finally smaller scale efficiency improvements. For hydrogen co-fired combustion turbines that cannot reasonably comply with the presumptive standards of performance for either subcategory, a State would first analyze lower percentages of hydrogen co-firing, followed by comprehensive turbine upgrades, and lastly smaller scale efficiency improvements. States would also be free to analyze additional potential source-specific BSERs for affected combustion turbine EGUs in either subcategory.

The EPA requests comment on the proposed requirement to consider certain control technologies as part of source-specific BSER determinations, and specifically on whether the Agency should require this approach as proposed or, in the alternative, provide it as a presumptively approvable approach to conducting a source-specific BSER analysis.

The EPA notes again that, under both the proposed subpart Ba and CAA section 111(d),[639] an affected EGU that cannot reasonably apply the EPA's BSER but can achieve the degree of emission limitation for the applicable subcategory through other reasonable systems of emission reduction cannot be given a less stringent standard of performance. In this case, the affected EGU's standard of performance would still reflect the degree of emission limitation achievable through application of the EPA's BSER.

The EPA has proposed in its revisions to subpart Ba that specific requirements would apply when invoking RULOF based on an affected source's remaining useful life.[640] Among other requirements, the EPA in an emission guideline would have to either identify the outermost date to cease operations for the relevant source category that qualifies for consideration of remaining useful life or provide a methodology and considerations for states to use in establishing such an outermost date. Proposed subpart Ba also provides that an affected source with a date to cease operations that is both imminent and prior to the outermost date could be eligible for a standard of performance that reflects that source's BAU. The EPA is proposing to supersede the application of subpart Ba for coal-fired steam generating units with respect to the proposed requirements to establish outermost and imminent dates to cease operations for invoking RULOF based on an affected EGU's remaining useful life. As explained earlier in this section of the preamble, the EPA has designed the subcategories for coal-fired affected EGUs under these emission guidelines to accommodate sources' self-identified operating horizons. This approach to subcategorization obviates the need to establish an outermost date to cease operations to guide states' and affected EGUs' consideration of remaining useful life. Additionally, the EPA is proposing to establish an imminent-term subcategory with a proposed BSER determination of routine operation and maintenance, which serves the same purpose as establishing an imminent date to cease operations under the RULOF provision. Although it is not anticipated that states will have a reason to invoke RULOF due to a coal-fired EGU's imminent date to cease operations based on the structure of the subcategories under these emission guidelines, states are not precluded from doing so based on unit-specific circumstances.

Because of the small number of sources in the oil- and natural gas-fired steam generating unit subcategories and the diversity of circumstances in which they operate, the EPA is not proposing to establish outermost or imminent dates to cease operations for the purpose of considering remaining useful life for these sources. Regardless, because the proposed BSER determinations for these EGUs is routine methods of operation and maintenance (other than for low-load oil- and natural gas-fired steam generating units), the EPA does not anticipate that states will find it necessary to invoke RULOF for these sources.

The EPA is also proposing to supersede the requirement in subpart Ba to establish imminent and outermost dates for the consideration of remaining useful life for affected combustion turbine EGUs. While, as discussed above in this section of the preamble, it is likely that some portion of the existing combustion turbine fleet will be reaching the end of its remaining useful life in the 2035 to 2040 timeframe, the structure of the proposed subcategories, the length of time between State plan submission and the compliance dates for the subcategories, and the staggered compliance dates for the two subcategories make it difficult to set a widely-applicable date or dates that represent an imminent cessation of operations. States would not be precluded from demonstrating that an affected combustion turbine EGU's remaining useful life is so short that it qualifies for a business-as-usual standard of performance (*i.e.,* that its remaining useful life is so short that the cost of any control would be unreasonably high). Similarly, based on the proposed BSERs for the subcategories and the staggered nature of the proposed compliance dates for combustion turbine EGUs, the EPA does not believe it is helpful to set an outermost date for the considering of remaining useful life for these units. The EPA requests comment on its proposal to supersede the requirements in subpart Ba to set imminent and outermost dates for the consideration of remaining useful life for affected combustion turbine EGUs. If commenters believe such dates would be useful to guide states' consideration of remaining useful life for affected existing combustion turbines, the EPA further requests input on what those dates could be, and why.

The proposed subpart Ba would require that any plan that applies a less stringent standard to a particular affected EGU based on remaining useful life must include the date by which the EGU commits to permanently cease operations as an enforceable

[639] As discussed earlier in this preamble, permitting a state to apply a less stringent standard to an affected EGU that can achieve the degree of emission limitation the EPA determined is required would be inconsistent with CAA section 111(d). See also 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(g)).

[640] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(h), (i)).

requirement.[641] The plan would also have to include measures that provide for the implementation and enforcement of such a commitment. The EPA is not proposing to supersede this proposed requirement for the purpose of this emission guideline; states that include a RULOF standard based on an affected EGU's remaining useful life must make the source's voluntary commitment to permanently cease operations by a date certain enforceable in the State plan.

Similarly, subpart Ba would require that if a State seeks to rely on a source's operating conditions, such as its restricted capacity, as the basis for invoking RULOF and setting a less stringent standard, the State plan must include that operating condition as an enforceable requirement.[642] This requirement would apply to operating conditions that are within an affected EGU's control and is necessary to ensure that a source's standard of performance matches what that source can reasonably achieve and does not undermine the stringency of these emission guidelines.

The proposed presumptively approvable standards of performance for affected EGUs in these emission guidelines are expressed in the form of rate-based emission limitations, specifically, as lb CO_2/MWh. Therefore, to ensure transparency and to enable the EPA, states, and stakeholders to ensure that RULOF standards do not undermine the presumptive stringency of these emission guidelines, the EPA is proposing to require that standards of performance determined through this RULOF mechanism be in the same form of rate-based emission limitations.[643]

The EPA seeks comment on implementation of the proposed subpart Ba requirements pertaining to determining a source-specific BSER and calculating a less stringent standard for sources invoking RULOF under these emission guidelines. It also seeks comment on the proposed requirements that are specific to these emission guidelines, including but not limited to the proposed requirement that states evaluate certain control options for affected coal-fired steam generating units in the long-term and medium-term subcategories and for affected combustion turbine EGUs as part of their source-specific BSER determination, the proposal to not provide outermost or imminent dates to cease operations for the consideration of remaining useful life, and the proposal to require RULOF standards of performance to be in the form of lb CO_2/MWh emission limitations.

c. Consideration of Impacted Communities

While the consideration of RULOF may warrant application of a less stringent standard of performance to a particular affected EGU, such standards have the potential to result in disparate health and environmental impacts to communities most affected by and vulnerable to impacts from those EGUs. Those communities could be put in the position of bearing the brunt of the greater health and environmental impacts resulting from an affected EGU implementing a less stringent standard of performance than would otherwise have been required pursuant to the emission guidelines. A lack of consideration of such potential outcomes would be antithetical to the public health and welfare goals of CAA section 111(d).

Therefore, the proposed subpart Ba revisions would require that states applying less stringent standards of performance consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the affected EGU in determining source-specific BSERs and the degree of emission limitation achievable through application of such BSERs.[644] The State will have identified these communities as pertinent stakeholders in the process of meaningful engagement, which is discussed in section XII.F.1.b of this preamble.

If the EPA finalizes the requirement under subpart Ba to consider the potential pollution impacts and benefits of control to the communities most affected by and vulnerable to emissions from a RULOF source communities as proposed, State plan submissions under these emission guidelines would have to demonstrate that the State considered such impacts and benefits in applying a less stringent standard of performance to such a source. The EPA expects that states' meaningful engagement with pertinent stakeholders on the State plan development generally will include engagement on any potential use of RULOF to apply less stringent standards of performance. The proposed requirement that states consider the potential pollution impacts and benefits of control in the context of a source-specific BSER analysis for a particular source is intended to provide for states' consideration of health and environmental effects on the communities that are most affected by and vulnerable to emissions from that particular source. As an example, the State plan submission could include a comparative analysis assessing potential BSER options for an affected EGU and the corresponding potential benefits to the identified communities under each option. If the comparative analysis shows that emissions from an affected EGU could be controlled at a higher cost but that such control benefits the communities that would otherwise be adversely impacted by a less stringent standard of performance, the State could balance these considerations and determine that a higher cost is warranted for the source-specific BSER.

The plan submission under these emission guidelines must clearly identify the communities most affected by and vulnerable to emissions from the designated facility. The EPA is proposing that, in evaluating potential source-specific BSERs, a State must document any health or environmental impacts and benefits of control options and describe how it considered those impacts on the identified communities. Pursuant to the proposed meaningful engagement requirements discussed in section XII.F.1.b of this preamble, states' plan submissions would also be required to include a summary of the meaningful engagement the State conducted and a summary of stakeholder input received, including any engagement and input on RULOF sources and the calculation of less-stringent standards of performance.

The EPA solicits comments on additional ways in which states might consider potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from affected EGUs when determining a less-stringent standard pursuant to RULOF. In particular, the Agency is requesting comment on metrics or information concerning health and environmental impacts from affected EGUs that states can consider in source-specific RULOF determinations. As discussed in section XII.F.1.b, the EPA is also requesting comment on tools and methodologies for identifying communities that are most affected by and vulnerable to emissions from affected EGUs under these emission guidelines.

[641] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(h), (i)(3)).

[642] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(h)).

[643] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(f)(3)).

[644] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(k)).

d. The EPA's Standard of Review of State Plans Invoking RULOF

Under CAA section 111(d)(2), the EPA has the obligation to determine whether a State plan submission is ''satisfactory.'' This obligation extends to all aspects of a State plan, including the application of less stringent standards of performance that account for RULOF. Pursuant to CAA section 111(d) and the proposed subpart Ba provisions,[645] states carry the burden of making the demonstrations required under the RULOF mechanism and have the obligation to justify any accounting for RULOF in support of standards of performance that are less stringent than the proposed presumptively approvable standards in these emission guidelines. While the EPA has the discretion to supplement a State's demonstration, the EPA may also find that inadequacies in a State plan's demonstration are a basis for concluding that the plan is not ''satisfactory'' and may therefore disapprove the plan.

As a general matter, a less stringent standard of performance pursuant to RULOF must meet all other applicable requirements of subpart Ba and these emission guidelines.[646]

In determining whether a State has met its burden in providing a less stringent standard of performance based on RULOF, the EPA will consider, among other things, the applicability and appropriateness of the information on which the State relied. Both a demonstration that a particular affected EGU meets the threshold requirements to invoke RULOF and the determination of a source-specific standard of performance entail the use of technical, cost, engineering, and other information. The proposed subpart Ba revisions would require states to use information that is applicable to and appropriate for the particular source at issue.[647] This means that, when available, the State must use source- and site-specific information. This is consistent with the premise that invoking RULOF is appropriate for a particular source when there are fundamental differences between the EPA's BSER and that source's specific circumstances.

In some instances, site-specific information may not be available. In such cases, it may be reasonable for a State to use information from, *e.g.,* cost, engineering, and other analyses the EPA has provided to support this rulemaking. The EPA is proposing that states using non-site-specific information must explain why that information is reasonable to rely on to determine a less stringent standard of performance based on RULOF. Regardless of the information used, it must come from reliable and adequately documented sources, which the proposed subpart Ba revisions explain presumptively include sources published by the EPA, permits, environmental consultants, control technology vendors, and inspection reports.[648]

The EPA solicits comment on the types of source-specific and other information that states should be required to provide to support the inclusion of standards of performance based on RULOF in State plans, as well as on any additional sources of information that may be appropriate for states to use in this context.

e. Authority To Apply More Stringent Standards as Part of State Plans

As explained in the subpart Ba notice of proposed rulemaking, the EPA reevaluated its interpretation of CAA sections 111(d) and 116 and, consistent with its revised interpretation, has proposed revisions to subpart Ba to clarify that states may consider RULOF to include more stringent standards of performance in their State plans.[649] The allowance in CAA section 111(d)(1) that states may consider ''other factors'' does not limit states to considering only factors that may result in a less stringent standard of performance; other factors that states may wish to account for in applying a more stringent standard than provided in these emission guidelines include, but are not limited to, effects on local communities, the availability of control technologies that allow a particular source to achieve greater emission reductions, and local or State policies and requirements.

Pursuant to proposed subpart Ba, states seeking to apply a more stringent standard of performance based on other factors would have to adequately demonstrate that the standard is in fact more stringent than the presumptively approvable standard of performance for the applicable subcategory. However, a State would not be required to conduct a source-specific BSER evaluation for the purpose of applying a more stringent standard of performance, so long as the standard will achieve equivalent or better emission reductions. In this case, the EPA believes it is appropriate to defer to the State's discretion to impose a more stringent standard on an individual source because such a standard does not have the potential to undermine the presumptive stringency of these emission guidelines.

More stringent standards of performance must meet all applicable statutory and regulatory requirements, including that they are adequately demonstrated.[650] As for all standards of performance, the State plan must include requirements that provide for the implementation and enforcement of a more stringent standard. The EPA has the ability and authority to review more stringent standards of performance and to approve them provided that the minimum requirements of subpart Ba and these emission guidelines are met, rendering them federally enforceable.

The EPA requests comment on the implementation of the proposed subpart Ba provisions pertaining to more stringent standards of performance in the context of these particular emission guidelines.

3. Increments of Progress and Milestones for Affected EGUs That Have Elected To Commit To Cease Operations

The EPA's long-standing CAA section 111 implementing regulations at 40 CFR part 60, subpart Ba[651] provide that State plans must include legally enforceable increments of progress to achieve compliance for each designated facility when the compliance schedule extends more than a specified length of time from the State plan submission date.[652] The EPA's December 2022 proposed revisions to subpart Ba would require increments of progress when the compliance date is more than 16 months after the State plan submission deadline.[653] Under these proposed emission guidelines, the State plan submission date would be 24 months (see section XII.F.2 of this preamble) from promulgation of the emission

[645] CAA section 111(d)(2), 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(j)).

[646] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(l)).

[647] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(j)(1)).

[648] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(j)(2)).

[649] 87 FR 79176, 79204 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(m), (n)).

[650] 87 FR 79176, 79204 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(m)).

[651] See also 40 CFR 60.21(h).

[652] 40 CFR 60.24a(d).

[653] 87 FR 79176, 79204 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.24a(d)).

guidelines, which the EPA is currently anticipating will be June 2026. The proposed compliance dates for affected EGUs within the proposed subcategories all fall on or after January 1, 2030, which is more than 16 months after the State plan submission deadline. The EPA is therefore proposing to require that State plans include increments of progress as discussed in this section. For the purpose of these emission guidelines, the EPA refers to pre-compliance date, federally enforceable requirements associated with the planning, construction, and operation of natural gas or hydrogen co-firing infrastructure and CCS as increments of progress. The EPA is also proposing separate, federally enforceable ''milestones'' associated with activities surrounding enforceable dates to permanently cease operations for steam generating EGUs in the imminent-term, near-term, and medium-term subcategories. These additional State plan requirements are intended to ensure that affected coal-fired steam generating units can complete the steps necessary to qualify for a subcategory with a less stringent BSER and to provide the public assurance that those steps will be concluded in a timely manner.

a. Increments of Progress

The EPA is proposing to adopt emission guideline-specific implementation of the five generic increments specified in the CAA section 111(d) implementing regulations at 40 CFR 60.21a(h). These five increments of progress are: (1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency; (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; (3) Initiation of on-site construction or installation of emission control equipment or process change; (4) Completion of on-sites construction or installation of emission control equipment or process change; and (5) Final compliance. To this end, the EPA is proposing that State plans must include specified enforceable increments of progress as required elements for coal-fired EGUs that use natural gas co-firing to meet the standard of performance for the medium-term existing coal-fired steam generating subcategory and for natural gas-fired combustion turbine EGUs that use hydrogen co-firing to meet the standard of performance for hydrogen co-fired combustion turbine subcategory. The EPA is additionally proposing that State plans must include enforceable increments of progress for units that use CCS to meet the standard of performance for the long-term existing coal-fired steam generating subcategory or for the CCS combustion turbine subcategory.

Some increments have been adjusted to more closely align with planning, engineering, and construction steps anticipated for designated facilities that will be complying with standards of performance with natural gas or hydrogen co-firing or CCS, but they retain the basic structure and substance of the increments in the general implementing regulations. In addition, consistent with 40 CFR 60.24a(d), the EPA is proposing similar additional increments of progress for the long-term and medium-term coal-fired subcategories as well as both combustion turbine subcategories 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 proposing an additional increment of progress related to the identification of an appropriate sequestration site for the long-term coal-fired subcategory and the CCS combustion turbine subcategory. Finally, the proposed emission guidelines include an additional increment of progress that that applies solely to the hydrogen co-fired combustion turbine subcategory related to securing sufficient hydrogen contract capacity to meet the standard of performance.

The EPA notes that affected EGUs do not necessarily have to implement the EPA's BSER technology to comply with their applicable standards of performance. For example, affected EGUs in the medium- and long-term coal-fired steam generating unit subcategories may meet their standards of performance using approaches other than natural gas co-firing and CCS, respectively. Where the owners or operators of affected EGUs select compliance approaches that deviate from the BSER technology associated with a subcategory requiring increments of progress, the EPA proposes that the State plan would be required to specify increments of progress for the relevant affected EGUs that are consistent with the increments in 40 CFR 60.21a(h), as well as dates for achieving each increment.

The EPA is proposing that final compliance with the applicable standard of performance, also defined as the final increment of progress at 40 CFR 60.21a(h)(5), must occur no later than January 1, 2030 for steam generating units in the medium-term and long-term subcategories, no later than January 1, 2035 for combustion turbine EGUs in the CCS subcategory, and no later than January 1, 2032 for combustion turbine EGUs in the hydrogen co-fired subcategory.[654] For the remaining increments, the EPA is not proposing date-specific deadlines for achieving increments of progress. Instead, the EPA proposes that states must assign calendar day deadlines for each of the remaining increments for each affected EGU in their State plan submissions. The first increment of progress listed at 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. The EPA believes that allowing states to schedule sources' increments of progress would provide them with flexibility to tailor compliance timelines to individual facilities, allow simultaneous work toward separate increments, and still ensure full performance by the compliance date. The EPA solicits comment on this approach as well as whether the EPA should instead finalize date-specific deadlines or more general timeframes for achieving increments of progress rather than leaving the timing for most increments to State discretion. The EPA also seeks comment on the specific deadlines or timeframes that the EPA could assign to each increment under a more prescriptive approach.

The EPA is not proposing increments of progress for either the imminent- or near-term subcategories for coal-fired steam generating units, or for oil- or natural gas-fired steam generating units. The proposed BSERs for these affected EGUs are routine operation and maintenance, which does not require the installation of significant new emission controls or operational changes. Because there is no need for the types of increments of progress specified in 40 CFR 60.21a(h) to ensure that affected EGUs in the imminent and near-term coal-fired and oil- and natural gas-fired subcategories can achieve full compliance by the compliance date, the EPA is proposing that the requirement

[654] The EPA is proposing that the second phase of the standard of performance for existing hydrogen co-fired combustion turbines, which corresponds to co-firing 96 percent by volume low-GHG hydrogen, would start on January 1, 2038. However, the EPA is not proposing an increment of progress associated with this second phase because the Agency anticipates the relevant planning, design, and construction steps will have occurred ahead of the January 1, 2032 compliance date.

for increments of progress in 40 CFR 60.24a(d) does not apply to these units.

For coal-fired steam generating units falling within the medium-term subcategory and combustion turbine EGUs within the hydrogen co-fired subcategory (*i.e.,* units with proposed BSERs of co-firing clean fuels), the EPA proposes the following increments of progress 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 the facility anticipates along the way. (2) Awarding of contracts for boiler or turbine 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 or turbine modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis or hydrogen co-firing at 30 percent on an annual average basis, as appropriate for the applicable subcategory. (4) Completion of onsite construction of any boiler or turbine modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis or hydrogen co-firing at 30 percent on an annual average basis, as appropriate for the applicable subcategory. (5) Final compliance with the standard of performance by January 1, 2030 for coal-fired steam generating units and by January 1, 2032 for combustion turbine EGUs.

In addition to the five increments of progress derived from the CAA section 111(d) implementing regulations, the EPA is proposing an additional increment of progress for affected EGUs with proposed BSERs based on co-firing clean fuels (natural gas co-firing for medium-term coal-fired steam generating EGUs and hydrogen co-firing for hydrogen co-fired combustion turbine EGUs) to ensure timely completion of any pipeline infrastructure needed to transport natural gas or hydrogen to designated facilities within each subcategory. Affected EGUs would be required to demonstrate 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.

Affected EGUs within the hydrogen co-fired combustion turbine subcategory must meet an additional increment of progress to demonstrate they have secured access to hydrogen supplies sufficient to meet their anticipated 2032 fuel needs. This increment can be met by a capacity contract for hydrogen at volumes in 2032 consistent with the information provided in the final control plan and the pipeline specification included in the pipeline construction increment of progress.

For coal-fired EGUs falling within the long-term subcategory and for combustion turbine EGUs falling within the CCS subcategory (*i.e.,* units with proposed BSERs of CCS), the EPA proposes the following increments of progress as required, enforceable elements to be included in a State plan submission: (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. (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) Final compliance with the standard of performance by January 1, 2030 for coal-fired steam generating units and by January 1, 2035 for combustion turbine EGUs.

In addition to the five increments of progress derived from the CAA section 111(d) implementing regulations, the EPA is proposing two additional increments for affected EGUs that adopt CCS to meet the standard of performance for the long-term coal-fired steam generating unit and CCS combustion turbine subcategories. The first mirrors the proposed approach for the co-firing subcategories to ensure timely completion of pipeline infrastructure and the second is designed to ensure timely selection of an appropriate sequestration site. As the first additional increment, the EPA proposes that affected EGUs using CCS to comply with their standards of performance would be required to demonstrate 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, 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.

The second proposed additional increment of progress for affected EGUs using CCS to comply with their standards of performance is formulated to ensure timely completion of site selection for geologic sequestration of captured CO_2 from the facility. Affected EGUs within this subcategory must submit 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.

The EPA requests comment on the substance of each of the six proposed increments of progress for coal-fired steam generating units falling within the medium-term subcategory, the seven increments of progress for units within the hydrogen co-fired combustion turbine subcategory, and the seven increments of progress proposed for both subcategories that anticipate CCS adoption. The EPA seeks comment on whether the increments contain an appropriate level of specificity to establish clear, verifiable criteria to ensure that states and affected EGUs are taking the steps necessary to reach full compliance. If commenters believe they do not, the EPA requests comment on the appropriate level of specificity for each increment. Additionally, as discussed in section XII.F.1.b.ii of this preamble, the EPA is proposing a requirement that each State plan provide for the establishment of Carbon Pollution Standards for EGUs websites by the owners or operators of affected EGUs. The EPA is further proposing that State plans must require affected EGUs with increments of progress to post those increments, the schedule required in the State plan for achieving them, and any documentation necessary to demonstrate that they have been achieved to this website in a timely manner.

b. Milestones for Affected EGUs That Have Elected To Commit To Cease Operations

The EPA is proposing that State plans must include legally enforceable milestones for affected EGUs within the imminent-term, near-term, and medium-term coal-fired steam generating unit subcategories. As described in section X of this preamble, the applicability criteria for each of the subcategories of coal-fired steam generating units include an affected EGU's intended operating horizon; where owners or operators of affected EGUs have elected to commit to permanently cease operations by a date certain before January 1, 2040, and, where a State further elects to include such commitments as an enforceable element in a State plan, such EGUs will fall into one of these three subcategories. Accordingly, affected EGUs in the imminent-term, near-term, and medium-term subcategories have BSERs that are specifically tailored to and dependent on their shorter operating horizons. The EPA is aware that there are many processes an affected EGU must complete in order to permanently cease operation. Therefore, to ensure that affected EGUs can complete the steps necessary to qualify for a subcategory with a less stringent standard of performance and to provide the public assurance that those steps will be concluded in a timely manner, the EPA is proposing additional State plan requirements, referred to as ''milestones,'' for EGUs in the imminent-term, near-term, and medium-term subcategories.

The proposed milestone reporting requirements count backward from an affected EGU's date to permanently cease operations to ensure timely progress toward that date. Five years before any date used to determine the applicable subcategory under these emission guidelines or 60 days after State plan submission, whichever is later, designated facilities must submit an Initial Milestone Report to the applicable State administering authority 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. (2) A list of key milestones, metrics that will be used to assess whether each milestone has been met, and calendar day deadlines for each milestone. These milestones must include at least the following: notice to the official reliability authority of the retirement date; submittal of an official suspension filing (or equivalent filing) made to the affected EGU's reliability authority; and submittal of an official retirement filing with the unit's reliability authority. (3) An analysis of how the process steps, milestones, and associated timelines included in the Milestone Report compare to the timelines of similar units 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, balancing authority, public utility commission, or other applicable authority, as well as any filings with the SEC or notices to investors in which the plans for the EGU are mentioned and any integrated resource plan.

For each of the remaining years prior to the date to permanently cease operations that is used to determine the applicable subcategory, affected EGUs must submit an annual Milestone Status Report that addresses the following: (1) Progress toward meeting all milestones and related metrics identified in the Milestone Report; and (2) supporting regulatory documents, 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 proposing 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 federally enforceable 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 requests input on whether 6 months after the federally enforceable date is an appropriate period of time to capture any actions affected EGUs taken following cessation of operations.

The EPA is proposing that affected EGUs with reporting milestones for commitments to permanently cease operations would be required to 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 XII.F.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 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. The EPA requests comment on this proposed approach, specifically whether any jurisdictions present unique State circumstances that should be considered when defining milestones and the required reporting elements.

4. Testing and Monitoring Requirements

The EPA is proposing to require states to include in their plans 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 and reporting requirements. Under this proposal, affected EGUs would be required to 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 monitoring requirements of 40 CFR part 75 require most fossil fuel-fired boilers to use a CO_2 CEMS, including a CO_2 concentration monitor and stack gas flow monitor, although some oil- and natural gas-fired boilers may have options to use alternative measurement methodologies (*e.g.,* fuel flow meters). A CO_2 CEMS is the most technically reliable method of emission measurement for EGUs that burn solid fuels, as it provides a measurement method that is performance based rather than equipment specific and is verified based on NIST traceable standards. A CEMS provides a continuous measurement stream that can account for variability in the fuels and the combustion process. Reference methods have been developed to ensure that all CEMS meet the same performance criteria, which helps to ensure consistent, accurate data. Natural gas-fired combustion turbines have options under appendices D and G of 40 CFR part 75 to use fuel flowmeters in lieu of a CO_2 CEMS. The flue flowmeter data, paired with fuel quality data, is used to determine CO_2 mass emissions and heat input.

The majority of EGUs will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit emissions reports under 40 CFR part 75 as they have under existing programs, such as the Acid Rain Program (ARP) and the Regional Greenhouse Gas Initiative (RGGI)—a cooperative of several states formed to reduce CO_2 emissions from EGUs. The majority of coal- and oil-fired EGUs not subject to the ARP or RGGI are subject to the MATS program and, therefore, will have installed stack gas flow monitors and/or CO_2 concentration monitors necessary to comply with the MATS. Similarly, the majority of natural gas-fired combustion turbines that may be affected by this rule already use fuel flowmeters to monitor and report CO_2 mass emissions and heat input under appendices D and G of 40 CFR part 75. Relying on the same monitors that are certified and quality-assured in accordance with 40 CFR part 75 ensures cost efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs.

The EPA requests comment on monitoring and reporting requirements for captured CO_2 mass emissions and net electricity output, and on allowable testing methods for stack gas flow rate.

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 2022, to complement GHGRP subpart RR, the EPA proposed 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.[655 656 657]

The EPA is proposing 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 proposed GHGRP subpart VV. If the emitting EGU sends the captured CO_2 offsite, it must assure that the CO_2 is managed at a facility subject to the GHGRP requirements, and the facility injecting the CO_2 underground must report under GHGRP subpart RR or proposed GHGRP subpart VV. This proposal 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 CO2 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, 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 proposed GHGRP subpart VV. We also emphasize that this proposal 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 assure that captured CO_2 is managed at 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 proposed rule.

The EPA requests comment on the following questions related to additional monitoring and reporting of hourly captured CO_2 under 40 CFR part 75: (a) should EGUs with carbon capture technologies be required to monitor and report the hourly captured CO_2 mass emissions under 40 CFR part 75, (b) if EGUs with carbon capture technologies are not required to monitor and report the hourly captured CO_2 mass emissions, the calculation procedures for total heat input and NO_X rate in appendix F to 40 CFR part 75 may no longer provide accurate results; therefore, what changes might be necessary to accurately determine total heat input and NO_X rate, (c) to ensure accurate and complete accounting of CO_2 mass emissions emitted to the atmosphere and captured for use or sequestration, at what locations should CO_2 concentration and stack gas flow be monitored, and should other values also be monitored at those locations, (d) are there quality assurance activities outside of those required under 40 CFR part 75 for CO_2 concentration monitors and stack gas flow monitors that should be required of the monitors to accurately and reliably measure captured CO_2 mass emissions, and (e) what monitoring plan, quality assurance, and emissions

[655] 87 FR 36920 (June 21, 2022).

[656] 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'').

[657] As described in 87 FR 36920 (June 21, 2022), both subpart RR and proposed 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.

data should be reported to the EPA to support evaluation and ensure consistent and accurate data as it relates to CO_2 emissions capture.

The 40 CFR part 75 monitoring and reporting provisions require hourly reporting of total gross electricity output, including useful thermal output, but do not require the reporting of net electricity output. The EPA requests comment on the following questions related to reporting of net electricity output: (a) should EGUs be required to measure and report total net electricity output, including useful thermal output, under 40 CFR part 75, (b) what guidance should the EPA provide on how to measure and apportion net electricity output, (c) should EGUs measure and report net electricity output at the unit or facility level, and (d) what monitoring plan, quality assurance, and output data should be reported to the EPA to support evaluation and ensure consistent and accurate data as it relates to total net electricity output.

To calculate CO_2 mass emissions at a fossil fuel-fired boiler, the EGU typically measures CO_2 concentration and flue gas flow rate as the exhaust gases from combustion pass through the stack (or duct). Under 40 CFR part 75, EGUs must complete regular performance tests on the flue gas flow monitor based on EPA Reference Method 2 or its allowable alternatives that are provided in 40 CFR part 60, appendices A–1 and A–2. In general, the allowable alternative measurement methods reduce or eliminate the potential overestimation of stack gas flow rate that results from the use of EPA Reference Method 2 when the specific flow conditions (*e.g.,* angular flow) are present in the stack. However, EGUs with stack gas flow monitors are not required to use the allowable alternative measurement methods and EGUs may change methods at any time. The EPA requests comment on the following questions related to the use of EPA Reference Method 2 and its allowable alternatives for stack gas flow monitors under 40 CFR part 75: (a) should or under what conditions should EGUs be required to conduct a flow study and choose the appropriate EPA reference method for each stack gas flow monitor based on the results of the study, (b) once an EGU selects the use of an EPA reference method for a stack gas flow monitor, regardless of the basis for that selection, should the EGU be required to continue using the same EPA reference method until a flow study or other engineering justification is made to change the EPA reference method, and (c) what additional monitoring plan, quality assurance, and emissions data should be reported to the EPA to support evaluation and ensure consistent and accurate data as it relates stack gas flow rate and performance of the stack gas flow monitor.

E. Compliance Flexibilities

In developing these proposed emission guidelines, the EPA has heard from stakeholders seeking flexibility in complying with standards of performance under these emission guidelines. In particular, stakeholders have requested that the EPA allow states to include flexibilities such as averaging and market-based mechanisms in their State plans, as has been permitted under prior EPA rules. The EPA is proposing to allow states to incorporate averaging and emission trading into their State plans, provided that states ensure that use of these compliance flexibilities will result in a level of emission performance by the affected EGUs that is equivalent to each source individually achieving its standard of performance. As discussed below, the EPA also recognizes that the structure of the proposed subcategories and associated degrees of emission limitation, as well as the unique characteristics of the existing sources in the relevant source categories, will likely require that certain limitations or conditions be placed on the incorporation of averaging and trading in order to ensure that such standards are at least as stringent as the EPA's BSER. This section discusses considerations related to such compliance flexibilities in the context of this particular rule and set of regulated sources—existing steam generating units and existing combustion turbine EGUs—and solicits comment on whether certain types of averaging and trading maintain the stringency of the EPA's BSER.

1. Overview

In the proposed subpart Ba revisions, ''Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)'' (87 FR 79176; December 23, 2022), the EPA explained that under its proposed interpretation of CAA section 111, each State is permitted to adopt measures that allow its sources to meet their emission limits in the aggregate when the EPA determines, in any particular emission guideline, that it is appropriate to do so given, inter alia, the pollutant, sources, and standards of performance at issue. Thus, the EPA has proposed to return 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 of the BSER.[658] See 87 FR 79208 (December 23, 2022).

Consistent with the return to this longstanding position, the EPA is proposing to allow states to incorporate trading and averaging in their State plans under these emission guidelines. States would not be required to allow for such compliance mechanisms in their State plans but could provide for trading and averaging for existing steam generating units and/or existing combustion turbines at their discretion.[659] As discussed in section XII.C of this preamble, State plans must demonstrate that they achieve a level of emission performance by affected EGUs that is consistent with the application of the BSER. The EPA is therefore proposing that, in order to find that a State plan that includes trading or averaging is ''satisfactory,'' it must demonstrate that it maintains the level of emission performance for the source category that would be achieved if each affected EGU was individually achieving its presumptive standard of performance, after allowing for any application of RULOF. In the case of averaging, discussed in section XII.E.3 of this preamble, an equivalence demonstration would be relatively straightforward. For emission trading programs, ensuring equivalent emission

[658] The EPA has authorized trading or averaging as compliance methods in several emission guidelines. See, *e.g.,* 40 CFR 60.33b(d)(2) (emission guidelines for municipal waste combustors permit state plans to establish trading programs for NO_X emissions); 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 supplemental proposal to promulgate emission guidelines for the oil and natural gas industry, the EPA has also proposed to allow States to permit sources to demonstrate compliance in the aggregate. 87 FR 74702, 74812 (December 6, 2022).

[659] The EPA notes that these flexibilities, trading and averaging, would be used to comply with standards of performance, rather than to establish standards of performance in the first instance. In contrast to the RULOF mechanism, which, as described in section XI.D.2 of this preamble, States may use to establish different standards of performance than those described by the EPA's BSER, trading or averaging may be used to demonstrate compliance with already established standards of performance. That is, States incorporating trading or averaging would not need to undergo a RULOF demonstration for sources participating in trading or averaging programs.

performance in the aggregate may be more difficult.

Section XII.E.2 of this preamble discusses considerations related to the appropriateness of trading and averaging for affected EGUs in certain circumstances, *e.g.,* affected EGUs with proposed BSERs based on routine methods of operation and maintenance. Section XII.E.2 of this preamble also discusses program design examples as well as potential design elements and takes comment on whether these or other designs or design elements could ensure that use of emission trading or averaging does not undermine the stringency of the EPA's BSER. However, the Agency is not proposing a presumptively approvable averaging or trading approach at this time.

The EPA also notes that States that incorporate trading or averaging into their State plans would need to conduct meaningful engagement on this aspect of their plans with pertinent stakeholders, just as they would need to do for any other part of a plan. As discussed in greater detail in section XII.F.1.b 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 trading or averaging for compliance.

2. Emission Trading

The EPA is proposing to allow State plans to include emission trading programs as a compliance flexibility for affected existing EGUs under these emission guidelines and is taking comment on whether certain types of trading programs could satisfy the requirement to maintain equivalence with source-specific application of standards of performance. This section discusses considerations related to affected EGUs under these emission guidelines and how a State could potentially incorporate a rate-based trading program or a mass-based trading program in a way that preserves the stringency of the BSER.

a. Considerations for Emission Trading in State Plans

Emission trading has been used to achieve required emission reductions in the power sector for nearly 3 decades. In Title IV of the Clean Air Act Amendments of 1990, Congress specified the design elements for the Acid Rain Program, a 48-State allowance trading program to reduce SO_2 emissions and the resulting acid precipitation. Building on the success of that first allowance trading program as a tool for addressing multi-State air pollution issues, the EPA has promulgated and implemented multiple allowance trading programs since 1998 for SO_2 or NO_X emissions to address the requirements of the CAA's good neighbor provision with respect to successively more stringent NAAQS for fine particulate matter and ozone. The EPA currently administers eight power sector emission trading programs that differ in pollutants, geographic regions, covered time periods, and levels of stringency.[660] Annual progress reports demonstrate that EPA trading programs have been successful in mitigating the problems they were designed to address, exhibiting significant emission reductions and extraordinarily high levels of compliance.[661] In addition, several states have implemented regional or intrastate CO_2 emissions trading programs to address GHG emissions from the power sector (the RGGI and California trading programs, respectively).

In general, emission trading programs provide flexibility for EGUs to secure emission reductions at a lower cost relative to more prescriptive forms of regulation. Emission trading can allow the owners and operators of EGUs to prioritize emission reduction actions where they are the quickest or cheapest to achieve while still meeting electricity demand and broader environmental and economic performance goals. These benefits are heightened where there is a diverse set of emission sources (*e.g.,* variation in technology, fuel type, age, and operating parameters) included in an emission trading program. This diversity of sources is typically accompanied by differences in marginal emission abatement costs and operating parameters, resulting in heterogeneity in economic emission reduction opportunities that can be optimized through the compliance flexibility provided through emission trading. In addition, the EPA has observed, with the support of multiple independent analyses, that there is significant evidence that implementation of trading programs prompted greater innovation and deployment of clean technologies that reduce emissions and control costs.[662]

Emission trading may also provide important benefits. Having flexibility to prioritize the most cost effective emission reductions among affected EGUs may reduce the cost of compliance as well as provide flexibility for fleet management, while achieving the requisite level of emission performance. In particular, emission trading may provide some short-term operational flexibility.

At the same time, there may be challenges for implementing an emission trading program, especially in the context of the emission guidelines that the EPA is proposing here. The EPA notes that while the proposed emission guidelines include both steam generating units and combustion turbines, the fleet of affected steam generating units is expected to shrink under BAU projections (see section IV.F of this preamble), and the number of existing combustion turbines subject to these emission guidelines is limited (see section XI.C of this preamble) given the subcategory applicability thresholds. As a result, there is unlikely to be as much diversity in cost and emission performance among affected emission sources (resulting in less diversity in emission reduction opportunities and marginal abatement costs) as seen in prior emission trading programs for the electric power sector.

The utility of trading under these emission guidelines may also be obviated somewhat by the subcategories that the EPA has proposed to establish for existing coal-fired steam generating units and existing gas combustion turbines. The specific subcategories proposed under these emission guidelines for steam generating units are designed to provide for much of the same operational flexibility as would be provided through trading; as a result, the EPA believes that it would not be appropriate to allow affected EGUs in certain subcategories—imminent-term and near-term coal-fired steam generating units and natural gas- and oil-fired steam generating units—to comply with their standards of performance through trading. Similarly, the EPA believes it would not be

[660] The six current CSAPR trading programs are the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR SO_2 Group 1 Trading Program, CSAPR SO_2 Group 2 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR NO_X Ozone Season Group 3 Trading Program. The regulations for the six CSAPR programs are set forth at subparts AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, and GGGGG, respectively, of 40 CFR part 97. The regulations for the Texas SO_2 Trading Program are set forth at subpart FFFFF of 40 CFR part 97. The Acid Rain Program SO_2 trading program is set forth in Title IV of the Clean Air Act Amendments of 1990.

[661] Environmental Protection Agency (2021). Power Sector Programs—Progress Report. EPA. *https://www3.epa.gov/airmarkets/progress/reports/index.html.*

[662] LaCount, M.D., Haeuber, R.A., Macy, T.R., & Murray, B.A. (2021). Reducing Power Sector Emissions under the 1990 Clean Air Act Amendments: A Retrospective on 30 Years of Program Development and Implementation. Atmospheric Environment (Oxford, England: 1994), 245, 1–10. *https://doi.org/10.1016/j.atmosenv.2020.118012.*

appropriate to allow affected EGUs with less-stringent, source-specific standards based on RULOF to comply with those standards of performance through trading. As discussed in section X.D.3 of this preamble, the proposed BSER determinations for the imminent- and near-term coal-fired steam generating unit subcategories are designed to take into account factors such as operating horizon and load level (expressed as annual capacity factor) and, as a result, are based on routine methods of operation and maintenance. Natural gas- and oil-fired steam generating units also have proposed BSER determinations based on routine methods of operation and maintenance. An emission trading program that includes affected EGUs that have BSERs and resulting standards of performance based on limited expected emission reduction potential—or, in the case of affected EGUs for which states have invoked RULOF, less stringent standards of performance—may introduce the risk of undermining the intended stringency of the BSER for other facilities.

The EPA also believes that emission trading may be inappropriate for some subcategories of affected EGUs based on other, subcategory-specific reasons. 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. This consideration may be relevant for affected EGUs in the long-term coal-fired steam generating unit subcategory and the CCS combustion turbine subcategory that comply with their standards of performance using CCS. Additionally, the utilization applicability criterion for existing combustion turbines creates a barrier to emission trading under these emission guidelines. Specifically, existing combustion turbines that are greater than 300 MW qualify as affected EGUs and thus have applicable standards of performance only when they operate at an annual capacity factor of greater than 50 percent. When they operate at an annual capacity factor of 50 percent or less, they are not subject to standards of performance. The EPA believes that the fact that units may fall in or out of a trading program from year to year very likely precludes their inclusion in any such program as a practical matter.

The EPA requests comment on these challenges and on whether, in light of these and other considerations, emission trading should be permitted for certain subcategories and not permitted for others, and on whether emission trading should be limited to within certain subcategories, and why. In the following sections, the EPA discusses potential rate-based and mass-based emission trading program approaches that could potentially be included in a State plan and solicits comment on applied implementation issues in the context of these proposed emission guidelines and the considerations discussed in this subsection XII.E.2.a of the preamble.

b. Rate-Based Emission Trading

A rate-based trading program allows affected EGUs to trade compliance instruments that are generated based on their emission performance. This section describes one method of how states could establish a rate-based trading program as part of a State plan. The EPA requests comment on whether this or another method of rate-based trading could demonstrate equivalent stringency as would be achieved if each affected EGU was achieving its standard of performance.

In this example, affected EGUs that perform at a lower emission rate (lb CO_2/MWh) than their standard of performance would be issued compliance instruments that are denominated in one ton of CO_2. A tradable 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 may 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. This may pose a challenge for states trying to demonstrate equivalence with the intended stringency of the BSER.

These compliance instruments could be transferred among affected EGUs, making them ''tradable.'' Compliance would be demonstrated for an affected EGU based on a combination of 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 the rate-based standard of performance for the affected EGU.

Specifically, each affected EGU would 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 control period 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 generation in MWh. Affected EGUs 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 with a rate adjustment as each affected EGU performs its compliance demonstration.

In general, rate-based emission trading can by design assure achievement of the requisite level of emission performance for affected sources, because reduced utilization and retirements are automatically accounted for in the award of the compliance instrument. By default, only operating affected EGUs could receive or participate in the trading of compliance instruments.

The EPA is seeking comment on whether rate-based emission trading might be appropriate under these emission guidelines, taking into consideration the discussion of the appropriateness of trading for certain subcategories in section XII.E.2.a of this preamble. In particular, the EPA requests comment on whether and how a rate-based emission trading program could be designed to ensure equivalent stringency as would be achieved if each participating affected EGU was achieving its source-specific standard of performance, given the structure of the proposed subcategories and their proposed BSERs. The EPA also requests comment on any other methods of rate-based trading that would preserve the stringency of the BSER.

c. Mass-Based Emission Trading

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 emission budget. Each allowance would represent a tradable permit to emit one ton of CO_2, with affected EGUs required to surrender allowances in a number equal to their reported CO_2

emissions during each compliance period. This section describes one method of how states could establish a mass-based trading program as part of a State plan. The EPA requests comment on whether this or another method of mass-based trading could ensure equivalent stringency as would be achieved if each participating affected EGU was achieving its source-specific standard of performance.

As previously discussed, mass-based emission trading has been used in the power sector at the Federal, regional, and State levels for nearly 3 decades. Owners and operators of EGUs, utilities, and State agencies thus have extensive familiarity with mass-based emission trading, which could make the design and implementation of a mass-based trading program as part of a State plan relatively straightforward. However, this familiarity comes with an awareness on the part of states and the EPA of the need to tailor the design of a mass-based emission trading program to the situation in which it is applied. Past experience shows that emission budgets have often been overestimated when set many years in advance of the start of a program, as economic and technological conditions have changed significantly between the time the program was adopted and when compliance obligations begin. Projecting affected EGU fleet composition and utilization beyond the relative near term has become increasingly challenging, driven by factors including changes in relative fuel prices and continued rapid improvement in the cost and performance of wind and solar generation, along with new incentives for technology deployment provided by the IIJA and the IRA. Critically, if affected EGUs reduce utilization or exit the source category, the remaining affected EGUs face a reduced or eliminated obligation to improve their emission performance. In this case, the emission budget would be established at a level such that the sources would not be collectively meeting the required level of emission performance commensurate with each source achieving its rate-based standard of performance.

One program design states might employ to ensure that affected EGUs participating in a mass-based trading program continue to meet the level of emission performance prescribed by category-wide, source-specific implementation of the rate-based standards of performance includes regularly adjusting emission budgets to account for sources that cease operations or change their utilization. One budget adjustment method that the EPA has developed is dynamic budgeting, as applied in the Good Neighbor Plan,[663] in which budgets are updated annually based on recent historical generation. States could apply a similar dynamic budgeting process to mass-based trading implemented under these emission guidelines. In this context, states could establish an emission budget based on the unit-specific standards of performance of the participating affected EGUs, as described in section XII.D of this preamble, multiplied by each affected EGU's recent historical generation. The emission budget would be updated regularly to account for units that reduce utilization or cease operation. This is one way that states could assure achievement of the requisite level of emission performance for affected EGUs through mass-based trading, though the EPA acknowledges that existing State or regional mass-based trading programs may have developed other regular emission budget adjustment methods that could potentially provide similar assurance and might provide a model that could be applied for trading under these emission guidelines.

The EPA also acknowledges that other methods could be used to establish an emission budget that, in conjunction with the aforementioned dynamic budget approach, could achieve at least the requisite level of emission performance consistent with application of the BSER. States could use a single rate at the level of the subcategory or source category that is, for example, as stringent as the most controlled unit in the group (based on unit-specific standards of performance as defined in section XII.D.1) to establish the emission budget.

The EPA is seeking comment on whether mass-based emission trading might be appropriate under these emission guidelines, taking into consideration the discussion of the appropriateness of trading for certain subcategories in section XII.E.2.a of this preamble. In particular, the EPA requests comment on whether and how a mass-based emission trading program could be designed to ensure equivalent stringency as each participating affected EGU achieving its source-specific standard of performance, given the structure of the proposed subcategories and their proposed BSERs. The EPA is also seeking comment on whether the method of mass-based emission trading using dynamic budgeting, as discussed in this section, might be appropriate under these emission guidelines. The EPA is also seeking comment on other approaches or features that could ensure that emission budgets reflect the stringency that would be achieved through unit-specific application of rate-based standards of performance.

d. General Emission Trading Program Implementation Elements

The EPA notes that states would need to establish procedures and systems necessary to implement and enforce an emission trading program, whether it is rate-based or mass-based, if they elect to incorporate emission trading into their State plans. This would include, but is not limited to, establishing compliance timeframes and 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. Additionally, for states implementing a mass-based emission trading program, State plans would need to specify how allowances would be distributed to participating affected EGUs.

The EPA acknowledges that the proposed dates as of which standards of performance would apply for sources covered by these emission guidelines differ by subcategory: January 1, 2030, for all steam generating units; January 1, 2032, for the hydrogen co-fired combustion turbine subcategory; and January 1, 2035, for the CCS combustion turbine subcategory. If trading is permitted for two or more of these sets of sources, this difference could potentially pose an implementation challenge where a trading program includes these sources. To address this issue, a program could, for example, begin in 2030 for steam generating units and bring in combustion turbine EGUs later, or states could delay implementation of a trading program to coincide with the later combustion turbine date. The Agency requests comment on potential ways to address this implementation issue in the context of a State plan, and whether this issue impacts the utility or feasibility of trading across subcategories.

The EPA is also requesting comment on whether and to what extent there would be a desire to capitalize on the EPA's existing reporting and compliance tracking infrastructure to support State implementation of an

[663] The final Good Neighbor Plan was signed by the Administrator on March 15, 2023. At this time, the final action has not yet been published in the **Federal Register**.

emission trading program included in a State plan.

e. Banking of Compliance Instruments

The EPA requests comment on whether State plans should be allowed 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 stringency 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 early emission reductions, promote operational flexibility and planning, and facilitate market liquidity. 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 addition to requesting comment on whether the EPA should permit allowance banking, the EPA requests comment on the treatment of banked allowances, specifically whether all or only some portion of an allowance bank could be carried over for use in future control periods or if additional program design elements would be necessary to accommodate allowance banking.

f. Interstate Emission Trading

The EPA is requesting 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 operate in multiple states, interstate emission trading may increase compliance flexibility. 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 identical trading program requirements. There are many requirements for program reciprocity and approvability that would need to be established in the emission guidelines, in addition to providing mechanisms for submission and EPA review of State plans that include interstate trading mechanisms. Given the increased level of program complexity that would be necessary to accommodate interstate trading and the operational flexibilities already provided by the structure of the proposed subcategories and their proposed BSERs, the EPA requests comment on whether there is utility in providing for it under these emission guidelines. In addition, the EPA requests comment on the information, guidance, and requirements the EPA would need to provide for states to implement successful interstate emission trading programs.

3. Rate-Based Averaging

The EPA is proposing to allow State plans to include rate-based averaging as a compliance flexibility for affected EGUs under these emission guidelines. This section discusses how states could potentially incorporate a rate-based averaging program in a way that preserves the stringency of the EPA's BSER as well as some considerations related to incorporating averaging in State plans. The EPA is seeking comment on one potential method, described in this section, as well as other methods that could maintain the required level of emission performance equivalent to each source individually achieving its standard of performance.

Averaging allows multiple affected EGUs to jointly meet a rate-based standard of performance. Affected EGUs participating in averaging could, for example, demonstrate compliance through an effective CO_2 emission rate that is based on a gross generation-based weighted average of the required standards of performance of the affected EGUs that participate in averaging. The scope of such averaging could apply at the facility level or the owner or operator level. This method for calculating a composite rate could demonstrate equivalence with source-specific standards of performance.

Averaging can provide potential benefits. First, it offers some flexibility for sources to target cost effective reductions at any affected EGU. 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.

However, the EPA notes that the subcategory approach in these emission guidelines already provides significant operational flexibility for affected EGUs, potentially making the provision of further flexibility through averaging redundant or inappropriate, especially at the owner or operator level.

The EPA is seeking comment on the utility of rate-based averaging as a compliance flexibility, as well as on the illustrative method for developing a composite standard of performance for the purposes of rate-based averaging. The EPA is also seeking comment on any other considerations related to rate-based averaging, including whether the scope of averaging should be limited to a certain level of aggregation (*e.g.,* to facility-level rate-based averaging) or to certain subcategories.

4. Relationship to Existing State Programs

The EPA recognizes that many states have adopted binding 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 GHG 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 EPA's proposed emission guidelines differs significantly from the range of policies and programs employed by states to reduce power sector CO_2 emissions, and this proposal operates more narrowly to improve the CO_2 emission performance of a subset of EGUs within the broader electric power sector. The Agency recognizes the importance of State programs and their potential to reduce power sector CO_2 emissions through a range of strategies broader than those proposed here pursuant to CAA section 111(d). The EPA seeks comment on whether there are any elements of the proposed emission guidelines that might interfere with the implementation of State requirements that limit CO_2 emissions from EGUs that may be subject to the proposed emission guidelines.

F. State Plan Components and Submission

This section describes the proposed requirements for the contents of State plans, the proposed timing of State plan submissions, and 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 a Federal plan.

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 proposing to add to, supersede, or otherwise vary the requirements of subpart Ba for the purposes of State plan submissions under these particular emission guidelines,[664] those proposals are addressed explicitly in section XII.F.1.b on specific State plan requirements and throughout this preamble. Unless expressly amended or superseded in these proposed emission guidelines, the provisions of subpart Ba would apply.

1. Components of a State Plan Submission

The EPA is proposing that a State plan must include a number of discrete components. These proposed plan components include those that apply for all State plans pursuant to 40 CFR part 60, subpart Ba. The EPA is also proposing additional plan components that are specific to State plans submitted pursuant to these emission guidelines. For example, the EPA is proposing 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. The EPA's proposed revisions to subpart Ba would add one item to the list of administrative criteria related to meaningful engagement (element 9 in the list below).[665] If that criterion is finalized as proposed, the complete list of applicable administrative completeness criteria for State plan submissions would be: (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 official State regulation(s) or document(s) submitted for approval and incorporated by reference into the plan, signed, stamped, and dated by the appropriate State official indicating that they are fully adopted and 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. For revisions to the approved plan, the submission must indicate the changes made to the approved plan by redline/strikethrough; (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 60.23, 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 60.23; (8) Compilation of public comments and the State's response thereto; and (9) Evidence of meaningful engagement, including a list of pertinent stakeholders, a summary of the engagement conducted, and a summary of stakeholder input received.

Pursuant to subpart Ba, the technical criteria required for all plans must include each of the following:[666] (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 non-duplicative.

b. Specific State Plan Requirements

To ensure that State plans submitted pursuant to these emission guidelines are consistent with the requirements of subpart Ba, the EPA is proposing regulatory requirements that would apply to all affected EGUs subject to a standard of performance under a State plan pursuant to these proposed emission guidelines, as well as requirements that apply to affected EGUs within specific subcategories. Standards of performance for affected EGUs included in a State plan must be quantifiable, verifiable, permanent, enforceable, and non-duplicative. Additionally, per CAA section 302(l), standards of performance must be continuous in nature. Additional proposed State plan requirements include:

- Identification of affected EGUs and the subcategory to which each affected EGU is assigned;
- Identification of standards of performance for each affected EGU in lb CO_2/MWh-gross basis, including provisions for implementation and enforcement of such standards;
- Identification of enforceable increments of progress and milestones, as required for affected EGUs within the applicable subcategory, included as enforceable elements of a State plan;
- If relevant, identification of applicable enforceable requirements that are prerequisites for inclusion of an affected EGU in a specific subcategory, such as enforceable commitments to cease operations by a specified date or to limit annual capacity factor, where a State and the owner or operator of an affected EGU have chosen to rely on such commitments in order for the affected EGU to be included in a specific subcategory, included as enforceable elements of a State plan; and
- Identification of applicable monitoring, reporting, and recordkeeping requirements for affected EGUs.

The proposed emission guidelines include requirements pertaining to the methodologies states must use for establishing a presumptively approvable standard of performance for an affected EGU within a respective subcategory. These proposed methodologies are specified for each of the subcategories of affected EGUs in section XII.D.1 of this preamble.

[664] 40 CFR 60.20a(a)(1).

[665] 87 FR 79176, 79204 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.27a(g)(2)).

[666] 40 CFR 60.27a(g)(3)).

The EPA notes that standards of performance for affected EGUs in a State plan must be representative of the level of emission performance that results from the application of the BSER in these emission guidelines. As discussed in section XII.C of this preamble, in order for the EPA to find a State plan ''satisfactory,'' that plan must achieve the level of emission performance that would result if each affected source was 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, the structure and purpose of CAA section 111 require that those plans achieve an equivalent level of emission performance as applying the EPA's presumptive standards of performance to those sources (again, after accounting for any application of RULOF).

The proposed emission guidelines also include requirements that apply to states when they invoke RULOF in applying a less stringent standard of performance for an affected EGU than the presumptively approvable standard of performance. Such requirements include a demonstration by the State of why an affected EGU for which the State invokes RULOF cannot reasonably apply the BSER. The State would also be required to demonstrate where and how it considered the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the designated facility. The EPA expects that states would identify these communities, gather information about the potential pollution impacts and benefits of control, and document how they have considered that information in setting source-specific standards of performance for RULOF sources through their meaningful engagement processes.

In addition to consideration of impacts on and benefits to affected communities in the context of invoking RULOF for particular sources, the proposed revisions to the CAA section 111 subpart Ba implementing regulations include requirements for public engagement on overall State plan development. These requirements are intended to ensure robust and meaningful public involvement in the plan development process and to ensure that those who are most affected by and vulnerable to the impacts of a plan will share in the benefits of the plan and are protected from being adversely impacted. The proposed requirements are in addition to the existing public notice requirements under subpart Ba and, if finalized, would apply to State plan development in the context of 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.[667] 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.

In the subpart Ba revisions of December 2022, the EPA proposed to define meaningful engagement as:

> [T]timely engagement with pertinent stakeholder representation in the plan development or plan revision process. Such engagement must not be disproportionate in favor of certain stakeholders. It must include the development of public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to participation to assure pertinent stakeholder representation, recognizing that diverse constituencies may be present within any particular stakeholder community. It must include early outreach, sharing information, and soliciting input on the State plan.[668]

The EPA proposed to define that pertinent stakeholders ''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.'' [669] The preamble to the proposed revisions to subpart Ba notes that ''increased vulnerability of communities may be attributable, among other reasons, to both an accumulation of negative and lack of positive environmental, health, economic, or social conditions within these populations or communities.'' [670]

In the context of these emission guidelines, the air pollutant of concern is greenhouse gases and the air pollution is elevated concentrations of these gases in the atmosphere, which result in warming temperatures and other changes to the climate system that are leading to serious and life-threatening environmental and human health impacts. Thus, one set of impacts on communities that states should consider in identifying pertinent stakeholders is climate change 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.

These and other such climate change-related impacts can have a disproportionate impact on communities and populations depending on, inter alia, accumulation of negative and lack of positive environmental, health, economic, or social conditions. The Agency therefore expects states' pertinent stakeholders to include not only owners and operators of affected EGUs but also 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 refer to section III of this preamble, on climate impacts, to assist them in identifying their pertinent stakeholders).

Additionally, communities near affected EGUs may also be affected by a State plan or plan revision due to impacts associated with implementation of that plan. For example, communities located near affected EGUs may be impacted by construction and operation of infrastructure required under a State plan. Activities related to the construction and operation of new natural gas, CCS, and hydrogen pipelines may impact individuals and communities both locally and at larger distances from affected EGUs but near any associated pipelines. Thus, communities near affected EGUs and communities near pipelines constructed pursuant to State plan requirements should be considered pertinent stakeholders and included in meaningful engagement.

The EPA also acknowledges that employment at affected EGUs (including employment in operation and maintenance as well as in construction for installation of pollution control technology) is impacted by power sector trends on an ongoing basis, and states may choose to take energy communities into consideration as part of meaningful engagement. A variety of Federal

[667] 40 CFR 60.23(c)–(g); 40 CFR 60.23a(c)–(h).

[668] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.21a(k)).

[669] 87 FR 79176, 79191 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.21a(l)).

[670] 87 FR 79176, 79191 (December 23, 2022).

programs are available to support these communities.[671]

In some cases, an affected EGU may be located near State or Tribal borders and impact communities in neighboring states or Tribal lands. In such cases, the EPA believes it could be reasonable for a State to identify pertinent stakeholders in the neighboring State or Tribal land and to work with the relevant air pollution control authority to conduct meaningful engagement that addresses cross-border impacts. The EPA solicits comment on how meaningful engagement should apply to pertinent stakeholders outside a State's borders.

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. Consistent with the long-standing requirements for public engagement in State plan development, states should design meaningful engagement to ensure that all pertinent stakeholders are able to provide input on how affected EGUs in their State comply with their State plan requirements pursuant to these emission guidelines. Because these emission guidelines address air pollution that becomes well mixed and is long-lived in the atmosphere, the EPA expects states will consider communities and populations within the State that are both most impacted by particular affected EGUs and associated pipelines and that will be most affected by the overall stringency of State plans. (Note that the EPA addresses consideration of impacts of particular sources in the context of RULOF in section XII.D.2.c of this preamble.)

During the Agency's pre-proposal outreach, some environmental justice organizations and community representatives raised strongly held concerns about the potential health, environmental, and safety impacts of CCS. The EPA believes that any deployment of CCS can and should take place in a manner that is protective of public health, safety, and the environment, and that includes early and meaningful engagement with affected communities and the public. As stated in the Council on Environmental Quality's (CEQ) February 2022 Carbon Capture, Utilization, and Sequestration Guidance, ''the successful widespread deployment of responsible CCUS will require strong and effective permitting, efficient regulatory regimes, meaningful public engagement early in the review and deployment process, and measures to safeguard public health and the environment.'' [672]

As discussed in section V.C.3 of this preamble, the EPA is required to consider nonair quality health and environmental impacts, along with other considerations, in determining the BSER for both new and existing affected EGUs. In developing this proposed rulemaking, the EPA heard and carefully considered concerns expressed by affected communities regarding the possible impacts of CCS and hydrogen infrastructure in the context of selecting the proposed BSER. After weighing any adverse nonair quality health and environmental impacts of CCS and hydrogen co-firing along with the other BSER considerations, including the significant amount of emission reductions that can be achieved, and the reasonableness of the control costs, the EPA decided to propose that CCS and hydrogen co-firing meet the qualifications for the BSER for certain subcategories of sources. See, for example, section X.D.1.a.iii of this preamble.

The EPA recognizes, however, that facility- and community-specific circumstances, including the existence of cumulative impacts affecting a community's resilience or where infrastructure buildout would necessarily occur in an already vulnerable community, may also exist. The meaningful engagement process is designed to identify and 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 and hydrogen co-firing. 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.

If the revisions to subpart Ba are finalized as proposed, states would need to demonstrate in their State plans how they provided meaningful engagement with the pertinent stakeholders. This includes providing a list of the pertinent stakeholders, a summary of engagement conducted, and a summary of the stakeholder input provided, including information about the potential pollution impacts and benefits of control. As previously noted, the State must allow for balanced participation, including communities most vulnerable to the impacts of the plan. States must consider the best way to reach affected communities, which may include but should not be limited to notification through the internet. Other channels 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. The State should also consider any geographic, linguistic, or other barriers to participation in meaningful engagement for members of the public. If a State plan submission does not meet the required elements for notice and opportunity for public participation, including requirements for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or to disapprove the plan. As discussed in section XII.F.2 of this preamble, the EPA is proposing to provide 24 months from the date of publication of final emission guidelines for State plan submission, which should allow states adequate time to conduct meaningful engagement.

The EPA is requesting comment on what assistance states and pertinent stakeholders may need in conducting meaningful engagement with affected communities to ensure that there are adequate opportunities for public input on decisions to implement emissions control technology (including but not limited to CCS or low-GHG hydrogen). The EPA is also requesting comment on any tools or methodologies that states may find helpful for identifying communities that are most affected by and vulnerable to emissions from affected EGUs under these emission guidelines. The EPA is also requesting comment on whether it would be useful for the Agency to promulgate minimum approvability requirements for

[671] 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.*

[672] Carbon Capture, Utilization, and Sequestration Guidance, 87 FR 8808, 8809 (February 16, 2022), *https://www.govinfo.gov/content/pkg/FR-2022-02-16/pdf/2022-03205.pdf.*

meaningful engagement that are specific to these emission guidelines and, if so, what those requirements should be.

i. Specific State Plan Requirements for Existing Combustion Turbines Co-Firing Low-GHG Hydrogen

As discussed in section XI.C of this preamble, the EPA is proposing that the BSER for affected combustion turbine EGUs in the hydrogen co-fired subcategory is co-fired 30 percent low-GHG hydrogen by volume starting January 1, 2032, and 96 percent low-GHG hydrogen by volume starting January 1, 2038. Therefore, as discussed in section XII.D.1.c.ii of this preamble, the EPA is proposing a rate-based presumptive standard of performance for the hydrogen co-fired subcategory based on co-firing low-GHG hydrogen at these levels. However, CAA section 111 does not require that sources meet their applicable standards of performance by implementing the BSER. Therefore, affected combustion turbine EGUs in the hydrogen co-fired subcategory do not necessarily have to meet their standards of performance by co-firing hydrogen. However, should they choose to comply in this manner, the hydrogen that they co-fire to meet their standards of performance must be low-GHG hydrogen. Thus, the EPA is proposing that State plans require that affected EGUs in the hydrogen co-fired subcategory that meet their standards of performance by co-firing hydrogen demonstrate that they are co-firing low-GHG hydrogen. The EPA discusses its rationale for requiring low-GHG hydrogen to be used for compliance and its proposed definition of low-GHG hydrogen in sections VII.F.3.c.vi and VII.F.3.c.vii(F) of this preamble.

Section VII.K.3 of this preamble discusses the EPA's proposal to closely follow Department of Treasury protocols, which are currently under development, in determining how affected EGUs demonstrate compliance with the requirement to use low-GHG hydrogen. In the context of the proposed CAA section 111(b) rule for new combustion turbines, the EPA is taking comment on what forms of acceptable mechanisms and documentary evidence should be required for EGUs to demonstrate compliance with the obligation to co-fire low-GHG hydrogen, including proof of production pathway, overall emissions calculations or modeling results and input, purchasing agreements, contracts, and attribute certificates. The EPA is also taking comment, in the context of the CAA section 111(b) rule, on whether EGUs should be required to make fully transparent their sources of low-GHG hydrogen and the corresponding quantities procured, as well as on whether the EPA should require EGUs to demonstrate that their hydrogen is exclusively from facilities that produce only low-GHG hydrogen, as a means of reducing burden and opportunities for double counting. The EPA proposed to mirror the requirements it finalizes for verification of low-GHG hydrogen for new combustion turbine EGUs, as discussed in section VII.K.3 of this preamble, in the State plan requirements for affected existing combustion turbine EGUs in the hydrogen co-fired subcategory under these emission guidelines. The EPA therefore requests comment on the proposed approaches for verifying that low-GHG hydrogen is used for complying with an applicable standard of performance discussed in section VII.K.3 of this preamble. Additionally, the EPA requests comment on any unique considerations regarding the implementation of such verification requirements through State plans, including whether any additional or different requirements may be necessary to ensure that affected existing combustion turbine EGUs in the hydrogen co-firing subcategory that co-fire hydrogen to meet their standards of performance co-fire with low-GHG hydrogen.

ii. Specific State Plan Requirements for Transparency and Compliance Assurance

The EPA is proposing or requesting comment on several requirements designed to help states ensure compliance by affected EGUs with standards of performance, as well as to assist the public in tracking increments of progress toward the final compliance date.

First, the EPA is requesting comment on whether to require that an affected EGU's enforceable commitment to permanently cease operations, when a State relies on that 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 by December 31, 2034, to meet the applicability requirements for the near-term subcategory), must be in the form of an emission limit of 0 lb CO_2/MWh that applies on the relevant date.[673] 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 is requesting 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 date certain.

Second, the EPA is proposing that State plans that cover affected coal-fired steam generating units within any subcategory that is based on the date by which a source elects to permanently cease operations (*i.e.,* imminent-term, near-term, medium-term) must include, in conjunction with an enforceable date, the requirement that each source comply with applicable State and Federal requirements for permanently ceasing operation of the EGU, 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.

Third, the EPA is proposing 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. Although this information will also be required to be submitted directly to the EPA and the relevant State regulatory authority, the EPA is interested in ensuring that the information is made accessible in a timely manner to all pertinent stakeholders. The EPA anticipates that the owners or operators of a portion of the 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,[674] such that the burden of this website requirement for these units could be minimal.

In particular, the EPA is proposing that the owners or operators of affected EGUs would be required to post to their websites their subcategory designations and compliance schedules, including for increments of progress and milestones, leading up to full

[673] As explained in section X of this preamble, an affected EGU's federally enforceable commitment to cease operations is not part of that EGU's standard of performance but is rather a prerequisite condition for subcategory applicability.

[674] 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 Rule compliance information.

compliance with the applicable standards of performance. Owners or operators would also be required to post to their websites any information or documentation needed to demonstrate that an increment of progress or milestone has been achieved. Similarly, the EPA is proposing that emissions data and other information needed to demonstrate compliance with a standard of performance would also be required to be posted to the Carbon Pollution Standards for EGUs website for an affected EGU in a timely manner. The EPA is proposing that all information required to be made publicly available on the Carbon Pollution Standards for EGUs website be posted within 30 business days of the information becoming available to or reported by the owner or operator of an affected EGU. Information would have to remain on the website for a minimum of 10 years. The EPA solicits comment on these timeframes for posting and information retention, as well as on any concerns related to confidential business information.

The EPA proposes that owners or operators of affected EGUs that are also subject to similar website reporting requirements for the Coal Combustion Residuals Rule may use an already established website to house the reporting and recordkeeping information necessary to satisfy its Carbon Pollution Standards for EGUs website requirements. The EPA solicits comment on other ways to reduce redundancy and burden while satisfying the objective of making it easier for pertinent stakeholders to access affected EGUs' reporting and recordkeeping information.

To make it easier for the public to find the relevant Carbon Pollution Standards for EGUs websites, the EPA is also proposing that a State must establish a website that displays the links to the websites for all affected EGUs in its State plan.

Fourth, to promote transparency and to assist the EPA and the public in assessing increments of progress under a State plan, the EPA is proposing that State plans must include a requirement that the owner or operator of each affected EGU must report any deviation from any federally enforceable State plan increment of progress or milestone within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. In the report, the owner or operator of the affected EGU would 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 post the report to the affected EGU's Carbon Pollution Standards for EGUs website.

Fifth, to aid all affected parties and stakeholders in implementing these emission guidelines, the EPA is explaining its intended approach to exercising its enforcement authorities to ensure compliance while addressing genuine risks to electric system reliability. In these emission guidelines, the EPA has included subcategories for coal-fired steam generating units that take into account the operating horizons of these units and has provided relatively long planning and compliance timeframes. The EPA's proposed emission guidelines for existing combustion turbines likewise provide extensive lead time to meet the proposed degrees of emission limitation and apply only to a portion of the fleet that exceeds certain capacity and utilization thresholds. The Agency therefore does not anticipate that either the need for certain coal-fired steam generating units and existing combustion turbines to install controls, or affected EGUs' preexisting decisions to permanently cease operations, will result in resource constraints that would adversely affect electric reliability.

Nonetheless, the EPA believes it is appropriate to provide accommodations for potential isolated instances in which unanticipated factors beyond an owner or operator's control, and ability to predict and plan for, could have an adverse, localized impact on electric reliability. In such instances, affected EGUs could find themselves in the position of either operating in noncompliance with approved, federally enforceable State plan requirements or halting operations and thereby potentially impacting electric reliability.

CAA section 113 authorizes the EPA to bring enforcement actions against sources in violation of CAA requirements, seeking injunctive relief, civil penalties and, in certain circumstances, other appropriate relief. The EPA also has the discretion to agree to negotiated resolutions, including administrative compliance orders (''ACOs'') for achieving compliance with CAA requirements, that include expeditious compliance schedules with enforceable compliance milestones. The EPA does not generally speak to the intended scope of its enforcement efforts, particularly in advance of a violation actually occurring. However, the EPA is explaining its intended approach to ACOs here to provide confidence both with respect to electric reliability and that emission reductions under these emission guidelines will occur as required under CAA section 111(d).

The EPA would evaluate each request for an ACO for an affected EGU that is required to run in violation of a State plan requirement for reliability purposes on a case-by-case basis. However, as a general matter, the EPA anticipates that to qualify for an ACO, the owner/operator would need to demonstrate, as a minimum, that the following conditions have been satisfied:[675]

- The owner/operator of the affected EGU requesting an ACO has requested, in writing and in a timely manner, an enforceable compliance schedule in an ACO.
- The owner/operator of the affected EGU requesting an ACO has provided the EPA written analysis and documentation of reliability risk if the unit were not in operation, which demonstrates that operation of the unit in noncompliance is critical to maintaining electric reliability and that failure to operate the unit would result in violation of the established reliability criteria for the relevant control area/balancing authority, or cause reserves to fall below the required system reserve margin.
- The owner/operator of the affected EGU requesting an ACO has provided the EPA with written concurrence with the reliability analysis from the relevant electric planning authority for the area in which the affected EGU is located.
- The owner/operator of the affected EGU requesting an ACO has demonstrated that the need to continue operating for reliability purposes is due to factors beyond the control of the owner/operator and that the owner/operator of the affected EGU has not contributed to the purported need for an ACO.
- The owner/operator of the affected EGU requesting an ACO demonstrates that it has met all applicable increments of progress and milestones in the State plan.
- It can be demonstrated that there is insufficient time to address the reliability risk and potential noncompliance through a State plan revision.

If deemed appropriate to do so, the EPA would issue an ACO that includes

[675] This is a nonexclusive list of conditions. The EPA may choose to consider additional factors when deciding whether to enter an ACO in any given situation.

a compliance schedule and milestones to achieve compliance as expeditiously as practicable. The ACO would also include any operational limits, including limits on utilization reflecting the extent to which the unit is needed for grid reliability, and/or work practices necessary to minimize or mitigate any emissions to the maximum extent practicable during any operation of the affected EGU before it has achieved full compliance. The EPA reiterates that it would not be appropriate to request an ACO to address reliability risk and anticipated noncompliance in circumstances in which a State plan revision is possible.

The EPA requests 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.

2. Timing of State Plan Submissions

The EPA's proposed subpart Ba revisions would require states to submit State plans within 15 months after publication of the final emission guidelines.[676] For the purpose of these particular emission guidelines, the EPA is proposing to supersede that timeline and is proposing a State plan submission deadline that is 24 months from the date of publication of the final emission guidelines. Crucially, these proposed emission guidelines apply to a relatively large and complex source category—existing fossil fuel-fired steam generating units and existing fossil fuel-fired combustion turbines. Making the decisions necessary for State plan development will require significant analysis, consultation, and coordination between states, utilities, ISOs or RTOs, and the owners or operators of individual affected EGUs. The power sector is subject to many layers of regulatory and other requirements under many authorities, and the decisions states make under these emission guidelines will necessarily have to accommodate many overlapping considerations and processes. States' plan development may be additionally complicated by the fact that, unlike some other source sectors to which the general CAA section 111 implementing regulations apply, decision-making regarding control strategies and operations for affected EGUs may not be solely within the purview of the owners or operators of those sources; at the very least, affected EGUs often must obtain permission before making significant or permanent changes. The EPA does not believe it is reasonable to expect states and affected EGUs to undertake the coordination and planning necessary to ensure that their plans for implementing these emission guidelines are consistent with the broader needs and trajectory of the power sector in the space of 15 months.

Additionally, prior to an owner or operator providing a suggestion for a subcategory and standard of performance for an affected EGU to a State, that owner or operator will likely need to analyze options for complying with the applicable BSER for the subcategory. The EPA anticipates that some owners or operators of affected coal-fired steam generating units and affected combustion turbines will do feasibility and FEED studies for CCS prior to committing to it as a control strategy in a State plan. As discussed in section XII.B of this preamble and in the *GHG Mitigation Measures for Steam Generating Units* TSD, FEED studies take approximately 12 months to complete,[677] after which additional time is necessary to allow the conclusions from that study to be integrated into a State's planning process for certain affected EGUs. For other coal-fired steam generating units, there may also be planning, design, and permitting exercises that will be necessary for utilities to undertake prior to committing to a subcategory based on natural gas co-firing. While any boiler modifications required for affected EGUs that intend to co-fire natural gas are relatively straightforward, the owners or operators of EGUs in the medium-term subcategory may also be required to construct new pipelines to enable co-firing of 40 percent natural gas. Pipeline projects also require an initial planning and design process to determine feasibility and, in some cases, could involve FERC approval. Similar considerations apply for affected combustion turbine EGUs in the hydrogen co-fired subcategory with regard to any turbine upgrades that may be necessary to co-fire higher percentages of hydrogen and/or to the construction of any pipeline laterals that are necessary to supply the EGU with low-GHG hydrogen. Based on the approximately 12-month period that states and the owners or operators of affected EGUs will likely take to assess control strategies for these units, the EPA does not believe it is reasonable to require State plans to be submitted 15 months after promulgation of these emission guidelines.

In the proposed subpart Ba timelines for State plan submission, the EPA justified the generally applicable timelines in the context of public health and welfare impacts by proposing timelines that are as quick as is reasonably feasible for a generic set of emission guidelines under CAA section 111(d). The EPA is proposing 24 months for State plan timelines for these emission guidelines because 24 months is the quickest time that the EPA believes to be reasonably feasible for a State to submit a State plan based on the work and evaluation needed to establish which compliance strategy (such as CCS or co-firing) will be appropriate at a given EGU. Additionally, the EPA does not believe providing a longer timeline for the submission of State plans in this particular instance would ultimately impact how quickly the affected EGUs can comply with their standards of performance. As explained in section XII.B of this preamble and in the *GHG Mitigation Measures for Steam Generating Units* TSD, the EPA anticipates that CCS projects will take roughly 5 years to complete, assuming some steps are undertaken concurrently. If the EPA were to promulgate these emission guidelines in June 2024 and require State plan submissions in September 2025, the EPA anticipates that the soonest compliance could commence is in the third quarter of 2029. However, in this case, it is likely that at least some owners/operators of affected EGUs would have to commit to subcategories or control technologies before completing feasibility and FEED studies, which could result in the need for plan revisions and delayed emission reductions. In contrast, providing 24 months for State plan submission would mean that although plans would be due June 2026, owners or operators of affected EGUs would have had time to complete their feasibility and FEED studies and some initial planning steps before then. The EPA anticipates that owners or operators would need approximately another 3.5 years to reach full compliance, meaning that emission reductions would commence in the first quarter of 2030. The EPA does not believe that a difference of three months will adversely impact public health or welfare, especially when it is considered that providing more time for State plan development in this instance is more likely to ultimately result in certainty and timely emission reductions. The EPA solicits comment on the 24-month State planning period. The EPA specifically requests comments

[676] 87 FR 79182 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.23a(a)).

[677] *GHG Mitigation Measures for Steam Generating Units* TSD, chapter 4.7.1.

from owners and operators of affected EGUs regarding the steps, and amount of time needed for each step, that they would have to undertake to determine the applicable subcategories and to plan and implement the associated control strategies for each of their affected EGUs. Additionally, the EPA requests comment on the 24-month planning period from states, including on any unique characteristics of the fossil fuel-fired EGU source category that they believe merit planning timeframes longer than 15 months. Through outreach, many states have expressed a need for longer planning periods and the EPA solicits comment on whether this 24-month planning period accommodates that need. The EPA also requests comment from potentially impacted communities and other pertinent stakeholders on any considerations related to providing a longer State plan submission timeframe under these emission guidelines.

The EPA is additionally requesting comment on a potential bifurcated approach to State plan submissions for affected steam generating units and affected combustion turbine EGUs. In contrast to the proposed compliance deadline for steam generating units, the EPA is proposing compliance deadlines for combustion turbine EGUs in the CCS subcategory and combustion turbine EGUs in the hydrogen co-fired subcategory of January 1, 2035, and January 1, 2032 (with a second phase commencing on January 1, 2038), respectively. Despite the longer period between the anticipated promulgation of these emission guidelines and the proposed compliance deadlines for affected combustion turbine EGUs, the EPA is proposing that State plan submissions containing standards of performance and other applicable requirements for these units would be due 24 months after promulgation. Based on many of the same considerations regarding power sector planning and coordination discussed above, the EPA believes that states; owners and operators of affected EGUs; RTOs, ISOs, or other balancing authorities; and the public may benefit from considering the control strategies for all affected EGUs under these emission guidelines on the same timeline. Additionally, the EPA is cognizant of the need to achieve emission reductions and thus the public health and welfare benefits as soon as reasonably practicable.

However, the EPA also acknowledges that the compliance timeframes for combustion turbine EGUs are likely to be longer than those for steam generating units under these emission guidelines due to, *inter alia,* the need to phase installation of CCS across the power sector and the continued ramp-up in production and transmission capacity for low-GHG hydrogen. The EPA is therefore requesting comment on an approach in which states would submit two different plans on different timelines: a State plan addressing affected steam-generating units due 24 months after promulgation of these emission guidelines and a second State plan addressing affected combustion turbine EGUs due 36 months after promulgation of these emission guidelines. The EPA solicits comment on this staggered approach and on whether 36 months, or a longer or shorter period, could be an appropriate State plan submission deadline for combustion turbine EGUs, and why. The EPA requests that commenters explain if and how a longer State plan submission timeline for affected combustion turbine EGUs would be consistent with achieving the emission reductions under these emission guidelines as quickly as reasonably practicable, as well as on the potential interactions between the State plan submission time frame and the proposed compliance deadlines for combustion turbine EGUs. The EPA also solicits comment from potentially impacted communities and other pertinent stakeholders on any considerations related to providing a longer State plan submission timeframe for combustion turbine EGUs under these emission guidelines.

3. State Plan Revisions

The EPA expects that the State plan submission deadline proposed under these emission guidelines would give states, utilities and independent power producers, and stakeholders sufficient time to determine in which subcategory each of the affected EGUs falls 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.[678] State plan revisions are generally subject to the same requirements as initial State plan submissions under these emission guidelines and the subpart Ba implementation regulations, including meaningful engagement, and the EPA reviews State plan revisions against the applicable requirements of these emission guidelines in the same manner in which it reviews initial State plan submissions pursuant to 40 CFR 60.27a.

Approved State plan requirements 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 proposing a State plan submission date that is 24 months after the publication of final emission guidelines and is proposing that the first compliance date for a portion of affected EGUs would be on January 1, 2030. A State may choose to submit a plan revision prior to compliance with its existing State plan requirements; 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 requests comment on whether it would be helpful to states to impose a cut-off date for the submission of plan revisions ahead of the January 1, 2030, compliance date for coal-fired steam generating affected EGUs or ahead of the separate compliance dates for achieving the CCS-based or hydrogen co-firing-based standards for existing combustion turbines. Such a cut-off date, *e.g.,* January 1, 2028, would in effect establish a temporary moratorium on plan submissions in order to provide a sufficient window for the EPA to act on them and effectuate any changes to existing State plan requirements ahead of the final compliance date. State plan revisions would again be permitted after the final compliance date. As an alternative to a cut-off date for State plan revisions ahead of the compliance date, the EPA requests comment on the dual-path standards of performance approach discussed in section XII.F.4 of this preamble.

Under the proposed emission guidelines for existing coal-fired steam generating units, states would place their affected coal-fired steam generating units into one of four subcategories based on the time horizons over which those EGUs elect to operate. These subcategories are static—affected EGUs would not be able move between subcategories absent a plan revision.[679] However, the EPA

[678] 40 CFR 60.23a(a)(2), 60.28a.

[679] If the EPA finalizes an option for States to include dual paths for an affected coal-fired EGU or EGUs in their state plans, those affected EGUs would be able to choose between two subcategories prior to the final compliance date without the state's needing to revise its plan.

acknowledges that there may be instances in which a change in subcategory will be necessary. For affected coal-fired steam generating EGUs that are switching into the imminent-term, near-term, or medium-term subcategories, the EPA proposes to require that the State include in its State plan revision documentation of the affected EGU's submission to the relevant RTO or balancing authority of the new date it intends to permanently cease operations, any responses from and studies conducted by the RTO or balancing authority addressing reliability and any other considerations related to ceasing operations, any filings with the SEC or notices to investors in which the plans for the EGU are mentioned, any integrated resource plan, and any other relevant information in support of the new date. This documentation must be published on the Carbon Pollution Standards for EGUs website. These proposed requirements are modeled on the proposed milestones for sources electing to commit to permanently cease operations and are intended to help states, stakeholders, and the EPA ensure that the affected EGU's change in circumstances is sufficiently certain to warrant a State plan revision. Because of the long lead times for planning and implementation of control systems for affected EGUs, revising a State plan after the submission deadline has the potential to significantly disrupt states' and affected EGUs' compliance strategies. The EPA therefore believes it is reasonable to require affected EGUs and states to provide evidence that a source's circumstances have in fact changed, in order for the EPA to approve a plan revision. Affected EGUs switching into the imminent-term, near-term, or medium-term subcategories would also be required to comply with the proposed enforceable milestones applicable to those subcategories.

Some changes between subcategories of affected coal-fired steam generating EGUs, including from the long-term into the medium-term subcategory and from the imminent-term or near-term into the medium-term or long-term subcategory, would entail new standards of performance reflecting a different add-on control strategy than initially anticipated. In order to avoid undermining the stringency of these proposed emission guidelines, the EPA expects affected EGUs changing subcategories before the January 1, 2030, compliance deadline to make every reasonable effort to meet that compliance deadline. However, the EPA acknowledges that, in some circumstances, it may not be possible to complete the necessary planning and construction within a shortened timeframe. Additionally, unforeseen circumstances could require some affected EGUs to change subcategories after the final compliance deadline has passed (*e.g.,* to ensure reliability).

In these circumstances, the EPA is proposing that states may use the RULOF mechanism described in section XII.D.2 of this preamble to adjust the compliance deadlines for affected EGUs that cannot comply with their applicable standards of performance by the January 1, 2030, deadline. The EPA expects that states may be able to demonstrate that the change in subcategory constitutes an ''other circumstance[ ] specific to the facility . . . that [is] fundamentally different from the information considered in the determination of the best system of emission reduction in the emission guidelines.'' [680] In order to invoke RULOF to change a compliance deadline for an affected EGU that has switched subcategories, the EPA proposes that the State must first demonstrate that the affected EGU cannot meet the applicable presumptive standard of performance by the compliance deadline in these emission guidelines. As part of this demonstration the State would be required to provide evidence supporting the affected EGU's need to switch subcategories. The State would also be required to demonstrate that the need to invoke RULOF and to provide a different compliance deadline or less stringent standard of performance was not caused by self-created impossibility.

Like subcategorization for affected coal-fired steam-generating units, states would place their affected combustion turbine EGUs into one of the two subcategories in their State plans, along with the corresponding standard of performance. These subcategory designations are static—affected EGUs would not be able to move between subcategories absent a plan revision. The EPA expects that situations necessitating a change in subcategory for combustion turbine EGUs will be far less likely than for coal-fired steam-generating units. However, should the need arise for an affected combustion turbine EGU to change subcategories in a State plan, the same considerations discussed above for coal-fired steam generating units would apply. If a combustion turbine EGU changes subcategories in a manner that entails a new standard of performance that is based on a different control technology than initially anticipated, the EPA expects the owner or operator of that EGU to make every reasonable effort to meet the original compliance deadline for the newly applicable subcategory. For situations in which this is impossible, the EPA is proposing that states could use the RULOF mechanism as described above to provide a revised compliance deadline. As part of its RULOF demonstration, a State would be required to provide evidence supporting the affected combustion turbine's need to switch subcategories, as well as a demonstration that the need to invoke RULOF and to provide a different compliance deadline was not caused by the owner or operator's self-created impossibility.

Documentation related to these demonstrations must also be posted to the Carbon Pollution Standards for EGUs website. For example, it would not be reasonable for a State that has been notified that an RTO requires an affected EGU to switch subcategories to wait to revise its SIP until the remaining useful life of that EGU is so short as to preclude otherwise reasonable systems of emission reduction. To this end, the EPA is proposing to consider when a State knew or should have known that an affected EGU would need to switch subcategories when evaluating the approvability of State plans that include RULOF demonstrations. The EPA is additionally proposing to consider whether an affected EGU has been complying with its applicable milestones and increments of progress when evaluating RULOF demonstrations. The EPA encourages states to consult with their EPA Regional Offices as early as possible if they believe it may become necessary for an affected EGU to switch subcategories. The EPA requests comment on whether to set a deadline for states to provide plan revisions within a certain timeframe of knowing that an affected EGU needs to switch subcategories and on what timeframe would be appropriate.

The EPA is proposing that states invoking RULOF because an affected EGU cannot comply with its newly applicable presumptive standard of performance by the final compliance deadline first evaluate whether the affected EGU is able to comply with that standard by a different, later-in-time deadline. If a State can demonstrate that an affected EGU cannot reasonably comply with the applicable presumptive standard of performance under any reasonable compliance deadline, it may

[680] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(e)(3)).

then evaluate different systems of emission reduction according to the proposed RULOF mechanism described in section XII.D.2 of this preamble.

4. Dual-Path Standards of Performance for Affected EGUs

Under the structure of these emission guidelines as proposed, states would assign affected coal-fired steam generating units 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 between subcategories may not be able to meet compliance obligations for a new and different subcategory without considerable lag time and thus the switch would result in noncompliance and a loss of emission reductions. Similarly, states would be required to assign their affected combustion turbine EGUs to either the CCS or hydrogen co-fired subcategory in their State plans, at which point a unit could not switch between subcategories without a plan revision. 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 acknowledges that there may be circumstances in which the owner or operator of a coal-fired steam generating unit has not yet finalized its future operating plans and wishes to retain the option to choose between two different subcategories ahead of the proposed January 1, 2030, compliance date. Similarly, the owner or operator of a combustion turbine EGU may wish to retain the ability to choose between the CCS and hydrogen co-fired subcategories, particularly because the relatively long period between State plan submission and compliance means that a unit's circumstances could change materially in that time. The EPA is therefore soliciting comment on the following dual-path approach that may result in an additional flexibility for owners or operators of affected coal-fired steam generating units and affected combustion turbine EGUs that want additional time to commit to a particular subcategory without the need for a State plan revision.

The EPA is soliciting comment on an approach that allows coal-fired steam generating units and combustion turbine EGUs to have two different standards of performance submitted to the EPA in a State plan based on potential inclusion in two different subcategories. A State plan would be required to have all the associated components for each subcategory. For example, for an affected coal-fired steam generating unit that wants the option to be part of either the long-term or imminent-term subcategory, the State plan would include an enforceable standard of performance based on implementation of CCS and associated requirements, including increments of progress; as well as an enforceable requirement to permanently cease operations before January 1, 2033, and a standard of performance based on routine operation and maintenance. The affected EGU would be required to meet all compliance obligations for both subcategories, including increments of progress and/or milestones for commitments to cease operations, leading up to the compliance date of January 1, 2030. The State and the owner or operator of the affected EGU would be required to choose a subcategory for the affected EGU ahead of that date. Specifically, the EPA is proposing that the State must notify the EPA of its final applicable subcategory and standard of performance at least 6 months prior to the compliance date. For affected coal-fired steam generating units, the State would be required to notify the EPA of the applicable standard by July 1, 2029. For affected combustion turbine EGUs, the State would be required to notify the EPA of the applicable standard by the earliest compliance date, or July 1, 2031. If the State has not notified the EPA by the required date (July 1, 2029, or July 1, 2031) of the final applicable subcategory for the affected EGU, the EPA is proposing that a coal-fired steam generating unit would automatically be subject to the requirements of the subcategory that corresponds to the longer remaining life of the EGU, while a combustion turbine EGU would automatically be subject to the requirements of the CCS subcategory. Additionally, if the affected EGU misses an enforceable increment of progress, milestone (as described in section XII.D.3 of this preamble), or any other requirement for one of the two subcategories, the EGU will automatically be subject to the requirements of the other subcategory. If the EGU misses submissions for increments of progress and/or milestones for both subcategories, the EGU will automatically be subject to the requirements of the subcategory that corresponds to the longer remaining life of the EGU (for coal-fired steam generating units) or the CCS subcategory (for combustion turbine EGUs) and will additionally be found to be out of compliance for the increment of progress or milestone that it has missed.

The EPA is soliciting comment on this approach to provide flexibility to states and affected coal-fired steam generating units and affected combustion turbine EGUs. In some instances, owners or operators of affected EGUs may wish to have additional time to evaluate future operating plans; this proposed dual-path approach should provide owners or operators additional time to commit to a subcategory. However, with this additional time comes additional burden on owners and operators to demonstrate compliance with each of the requirements associated with two different subcategories that would be included in a State plan. As an example, a coal-fired steam generating unit intends to cease operations between 2038 and 2041. The State plan is submitted and contains two different enforceable dates to permanently cease operations, *e.g.,* December 31, 2038, with a standard of performance based on natural gas co-firing and December 31, 2041, with a standard of performance based on CCS, as well as an enforceable commitment by the State to choose one path or the other by July 1, 2029. The affected EGU would then be required to comply with the increments of progress for both the long-term (CCS) and medium-term (co-firing) subcategories, until the point at which the State decides which of the two paths in its plan it will require for the unit.

The EPA solicits comment on whether this proposed dual-path flexibility would have utility and on whether it could be implemented in a manner that ensures that states and affected coal-fired steam generating units and affected combustion turbine EGUs would be able to comply with applicable requirements in a timely manner. Additionally, the EPA solicits comment on whether notification deadlines of July 1, 2029, for coal-fired steam generating units, and July 1, 2031, for combustion turbine EGUs are the appropriate dates for a final decision between two potential standards of performance and why.

5. EPA Action on State Plans

Pursuant to proposed subpart Ba, the EPA would use a 60-day timeline for the Administrator's determination of completeness of a State plan submission[681] and a 12-month timeline

[681] The timeframes and requirements for state plan submissions described in this section also apply to state plan revisions. See generally 40 CFR 60.27a.

for action on State plans.[682] The EPA is not proposing to supersede these timelines; therefore, review of and action on State plan submissions will be governed by the requirements of revised subpart Ba. First, the EPA would 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.

Proposed subpart Ba would require the EPA to take 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). If the EPA finalizes the revisions to subpart Ba as proposed, the Administrator would have the option to fully approve, fully disapprove, partially approve, partially disapprove, and conditionally approve a State plan submission.[683] Any components of a State plan submission that the EPA approves become federally enforceable.

The EPA requests comment on the use of the timeframes provided in subpart Ba, as the EPA has proposed to revise it, for EPA actions on State plan submissions and for the promulgation of Federal plans for these particular emission guidelines.

6. Federal Plan Applicability and Promulgation Timing

The provisions of subpart Ba, including any revisions the EPA finalizes pursuant to its December 2022 proposal, will 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.[684] Where a State has failed to submit a plan by the submission deadline, the proposed revisions to subpart Ba would give the EPA 12 months from the State plan submission due date to promulgate a Federal plan; otherwise, the 12-month period starts from the date the State plan submission is deemed incomplete, whether in whole or in part, or from the date of the EPA's disapproval. The EPA may approve a State plan submission that corrects the relevant deficiency within the 12-month period, before it promulgates a Federal plan, in which case its obligation to promulgate a Federal plan is relieved.[685] 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, upon application by the owner or operator of an affected EGU, the EPA in its discretion may provide for 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.[686] Under the proposed revisions to subpart Ba, the EPA would also be required to conduct meaningful engagement with pertinent stakeholders prior to promulgating a Federal plan.[687]

As described in section XII.F.2 of this preamble, the EPA is proposing to allow states 24 months for a State plan submission after the promulgation of the final emission guidelines. Therefore, the EPA would be obligated to promulgate a Federal plan within 36 months of the final emission guidelines for all states that fail to submit plans. Note that this will be the earliest obligation for the EPA to promulgate Federal plans for states and that different triggers (*e.g.,* a disapproved State plan) will result in later obligations to promulgate Federal plans contingent on when the obligation is triggered.

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. 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.

XIII. Implications for Other EPA Programs

A. Implications for New Source Review (NSR) Program

CAA section 110(a)(2)(C) requires that a SIP include a New Source Review (NSR) program that provides for the ''regulation of the modification and construction of any stationary source . . . as necessary to assure that [the NAAQS] are achieved.'' Within the NSR program, the ''major NSR'' preconstruction permitting program applies to new construction and modifications of existing sources that emit ''regulated NSR pollutants'' at or above certain established thresholds. New sources and modifications that emit regulated NSR pollutants under the established thresholds may be subject to ''minor NSR'' program requirements or may be excluded from NSR requirements altogether. The NSR program for a State or local permitting authority with an approved SIP is implemented through 40 CFR 51.160 to 51.166, while the NSR program applying in areas for which the EPA or a delegated State, local or Tribal agency is the permitting authority is implemented through 40 CFR part 49 and 40 CFR 52.21.

NSR applicability is pollutant-specific and, for the major NSR program, the

[682] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.27a).

[683] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.27a(b)).

[684] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.27a(c)).

[685] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.27a(d)).

[686] 40 CFR 60.27a(e)(2).

[687] 87 FR 79176 (December 23, 2022), Docket ID No. EPA–HQ–OAR–2021–0527–0002 (proposed revisions at 40 CFR 60.27a(f)).

permitting 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. In addition, PSD permits can include requirements for specific pollutants for which there are no NAAQS.[688] 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 Emissions Rate (LAER) pursuant to CAA sections 171(3) and 173(a)(2) for any pollutant subject to NNSR. For sources subject to minor NSR, the CAA and EPA rules do not set forth prescriptive control technology requirements for minor NSR programs so these permits can be less stringent than major NSR permits. Due to the pollutant-specific applicability of the NSR program, it is conceivable that a source seeking to newly construct or modify may have to obtain multiple types of NSR permits (*i.e.,* NNSR, PSD, or minor NSR) depending on the air quality designation at the location of the source and the types and amounts of pollutants it emits.

A new stationary source is subject to major NSR requirements if its potential to emit (PTE) a regulated NSR pollutant exceeds statutory emission thresholds, upon which the NSR regulations define it as a ''major stationary source.'' [689] For PSD permitting, once a new stationary source is determined to be subject to major NSR for one regulated NSR pollutant (with the exception of GHG),[690] the source can be subject to major NSR requirements for any other regulated NSR pollutant if the PTE of that pollutant is at least the ''significant'' emissions rate (''SER''), as defined in 40 CFR 52.21(b)(23). In the case of GHG,[691] the EPA has not promulgated a GHG SER but applies a BACT applicability threshold of 75,000 TPY CO_2e.[692]

For an existing source, it can be subject to major NSR requirements if it is a major stationary source and its emissions increase resulting from a modification (*i.e.,* physical change or change in the method of operation) are equal to or greater than the SER for a regulated NSR pollutant, upon which the NSR regulations define it as a ''major modification.'' [693] As with new sources, the one exception to this applicability approach is GHG, which currently applies a BACT applicability threshold in lieu of a SER and can only be subject to major NSR if another pollutant is also subject to major NSR for the modification. Generally, an existing major stationary source triggering major NSR requirements for a regulated NSR pollutant would have both a significant emissions increase from the modification and a significant net emissions increase at the stationary source, and the calculation of the significant emissions increase differs depending on whether the modification is to an existing emissions unit, or the addition of a new emissions unit, or if it involves multiple types of emission units.[694] An existing major stationary source would trigger PSD permitting requirements for GHGs if it undertakes a modification and: (1) The modification is otherwise subject to PSD for a pollutant other than GHG; and (2) the modification results in a GHG emissions increase and a GHG net emissions increase that is equal to or greater than 75,000 TPY CO_2e and greater than zero on a mass basis.

Since GHG is not a criteria pollutant, it is regulated under the CAA's PSD program, but not under the NNSR or minor NSR programs. For new sources and modifications that are subject to PSD, the permitting authority must establish emission limitations based on BACT for each pollutant that is subject to PSD at the 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.[695] Permitting authorities may determine BACT by applying the EPA's five-step ''top down'' approach.[696] The ultimate determination of BACT is made by the permitting authority after a public notice and comment period of at least 30-days on the draft permit and supporting information.[697]

1. NSR Implications of a CAA Section 111(b) Standard

As noted above, BACT cannot be set at a level that is less stringent than the standard of performance established by an applicable NSPS, and the EPA refers to this minimum control level as the ''BACT floor.'' While a proposed NSPS does not establish the BACT floor for affected facilities seeking a PSD permit, once an NSPS is promulgated, it then serves as the BACT floor for any new major stationary source or major modification that meets the

[688] 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 fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.

[689] For PSD, the statute uses the term ''major emitting facility'' and defines it as a stationary source that emits, or has a PTE, at least 100 tons per year (TPY) if the source is in one of 28 listed source categories, or at least 250 TPY if the source is not a listed source category. CAA section 169(1). For NNSR, the emissions threshold for a major stationary source is 100 TPY, and lower thresholds apply for certain pollutants based on the severity of the nonattainment classification.

[690] As a result of the Supreme Court's decision in *UARG* v. *EPA,* the D.C. Circuit issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *EPA,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir. April 10, 2015), which, among other things, vacated the PSD and title V regulations under review in that case to the extent that they require a stationary source to obtain a PSD or title V permit solely because the construction of the source, or a modification at the source, emits or has the potential to emit GHGs at or above the applicable major NSR thresholds.

[691] Consistent with the 2009 Endangerment Findings, the PSD program treats GHG as a single air pollutant defined as the aggregate group of six gases: CO_2, N_2O, CH_4, HFCs, PFCs, and SF_6. 40 CFR 52.21(b)(49)(i).

[692] See Janet G. McCabe and Cynthia Giles, Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in *Utility Air Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014), *https://www.epa.gov/sites/default/files/2015-12/documents/20140724memo.pdf*.

[693] Per 40 CFR 52.21(b)(1)(i)(c), a minor source that undergoes a physical change that would itself be considered major, is subject to major source requirements.

[694] 40 CFR 52.21(a)(2)(iv); 40 CFR 52.21(b)(2)(i); 40 CFR 52.21(b)(3).

[695] 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].'').

[696] U.S. EPA, NSR Workshop Manual (Draft October 1990), *https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf*; U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011), *https://www.epa.gov/sites/default/files/2015-07/documents/ghgguid.pdf*.

[697] 40 CFR 124.10.

applicability of the NSPS and commences construction after the date of the proposed NSPS in the **Federal Register**.[698] In the context of combustion turbines that would be subject to this NSPS at 40 CFR part 60, subpart TTTTa, for any new major stationary source or major modification that commences construction or reconstruction of a stationary combustion turbine EGU after the date of publication of this proposed NSPS, the PSD permit should reflect a BACT determination that is at least as stringent as the promulgated NSPS for each of the source's affected EGUs.

However, the fact that a minimum control requirement 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 technologies for BACT beyond those that were considered in developing the NSPS. As explained above, BACT is a case-by-case review that considers a number of factors, and the review should reflect 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 development of an applicable NSPS.

2. NSR Implications of a CAA Section 111(d) Standard

With respect to the proposed action for emission guidelines, should it be promulgated, states will be called upon to develop a plan that establish standards of performance for each affected EGU that meets the requirements in the emission guidelines. In doing so, a State agency may develop a plan that results in an affected source undertaking a physical or operational change. Under the NSR program, undertaking a physical or operational change may require the source to obtain a preconstruction permit for the proposed change, with the type of NSR 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. More specifically, any time an existing source adds equipment or otherwise makes physical or operational changes to its facility, regardless of whether it has done so to comply with a national or State level requirement, the source may be required to obtain a NSR permit prior to making the changes unless the permitting authority determines that the action is exempt from permitting.[699]

Thus, there may be circumstances in which an affected source that is implementing a BSER requirement from a State plan is required to obtain a major NSR permit for one or more of its pollutants. One scenario in which this may occur is if an affected source experiences greater unit availability and reliability as a result of implementing its BSER requirement (*e.g.,* an efficiency based BSER) that, in turn, lowers the operating costs of its EGU. Since EGUs that operate at lower costs are generally preferred in the dispatch by the system operator over units with higher operational costs, the BSER implementation could result in improving the source's relative economics that would, in turn, increase its utilization of its EGU(s). With an increase in utilization resulting from the source implementing the BSER, the annual emissions from the EGU could increase, and if the emissions increase equals or exceeds the relevant SER for one or more of its pollutants, the source may be required to obtain a major NSR permit for the modification.

However, while it may be possible for an affected source to trigger major NSR requirements from actions it takes to implement a BSER requirement, we expect this situation to not occur often. As previously discussed in this preamble, states will have considerable flexibility in adopting varied compliance measures as they develop their plans to meet the standards of performance of the emission guidelines. One of these flexibilities is the ability for states to 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).[700]

B. Implications for Title V Program

Title V is implemented through 40 CFR parts 70 and 71. Part 70 defines the minimum requirements for State, local and Tribal (state) agencies to develop, implement and enforce a title V operating permit program; these programs are developed by the State and the State submits a program to the EPA for a review of consistency with part 70. There are about 117 approved part 70 programs in effect, with about 14,000 part 70 permits currently in effect. (See Appendix A of 40 CFR part 70 for the approval status of each State program.) Part 71 is a Federal permit program run by the EPA, primarily where there is no part 70 program in effect (*e.g.,* in Indian country, the Federal Outer Continental Shelf, and for offshore Liquified Natural Gas terminals).[701] There are about 100 part 71 permits currently in effect (most are in Indian country).

The 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 three 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 three

[698] U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), p. 25.

[699] The EPA sought to exempt environmentally beneficially pollution control projects from NSR requirements in a 2002 rule that codified longstanding EPA policy, but this rule was struck down in court. *New York* v. *EPA,* 413 F.3d 3, 40–42 (D.C. Cir. 2005) (*New York I*).

[700] 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'').

[701] In some circumstances, the EPA may delegate authority for part 71 permitting to another permitting agency, such as a Tribal agency or a state. The EPA has entered into delegation agreements for certain part 71 permitting activities with at least one Tribal agency. There are currently no States that do not have an approved part 70 program; thus, there is no need for the EPA to delegate part 71 delegated authority to any state at this time.

years, the newly applicable requirement must be incorporated at permit renewal.

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 solicits comment on whether, and under what circumstances, states might use this mechanism.

XIV. Impacts of Proposed Actions

In accordance with E.O. 12866 and 13563, the guidelines of OMB Circular A–4 and the EPA's Guidelines for Preparing Economic Analyses, the EPA prepared an RIA for these proposed actions. This RIA presents the expected economic consequences of the EPA's proposed rules, including analysis of the benefits and costs associated with the projected emission reductions for three illustrative scenarios. The first scenario represents the proposed CAA 111(b) combustion turbine phase 1 and phase 2 standards and 111(d) steam generating turbine proposals 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 Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule.''

The three scenarios detailed in the RIA, including the proposal 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 2042 from the perspective of 2024, using both a three percent and seven percent discount rate. 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, and 2040. 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 policy 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. The EPA also seeks comment on all aspects of the analysis, including modeling assumptions.

A. Air Quality Impacts

For the analysis of the proposed standards for new combustion turbines and for existing steam generating EGUs, which do not include the impact of the proposed standards for existing combustion turbines and the third phase of the proposed standards for new combustion turbines, total cumulative power sector CO_2 emissions between 2028 and 2042 are projected to be 617 million metric tons lower under the illustrative proposal scenario than under the baseline. Table 7 shows projected aggregate annual electricity sector emission changes for the illustrative proposal scenario, relative to the baseline.

TABLE 7—PROJECTED ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE PROPOSAL 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)
2028	−10	−7	−3	−12	−1
2030	−89	−64	−22	−107	−6
2035	−37	−21	−7	−41	−1
2040	−24	−13	−4	−30	−1

Note: Ozone season is the May through September period in this analysis.

The emissions changes in these tables do not account for changes in HAP that are likely to occur as a result of this action.

For the analysis of the proposed standards for existing combustion turbines and for the third phase of the proposed standards for new natural gas-fired EGUs, total cumulative power sector CO_2 emissions between 2028 and 2042 are estimated to be between 215–409 million metric tons lower than under the illustrative proposal scenario.

TABLE 8—ESTIMATED ELECTRICITY SECTOR EMISSION IMPACTS FROM EXISTING GAS STANDARD AND THIRD PHASE OF LOW-GHG HYDROGEN CO-FIRING STANDARD FOR NEW BASE LOAD COMBUSTION TURBINES

	CO_2 (million metric tons)	
	Low	High
2028	0	0
2030	0	0
2035	−20	−37
2040	−20	−39

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 proposed 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 proposal scenario is designed to reflect, to the extent possible, the scope and nature of the proposed guidelines. 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 impact of the IRA is to accelerate the ongoing shift towards lower emitting technology. In particular, 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 EGUs, and 10 GW of CCS retrofits on existing combined cycle EGUs by 2035. New combined cycle builds are 22 GW by 2030, and existing coal capacity continues to decline, falling to 69 GW by 2030 and 35 GW by 2040. As a result, the compliance cost of the proposed rules is lower than it would be absent the IRA.

We estimate the present value (PV) of the projected compliance costs for the analysis of the proposed standards for new combustion turbines and for existing steam-generating EGUs, which do not include the impact of the proposed standards for existing combustion turbines EGUs and the third phase of the proposed standards for new combustion turbines over the 2024 to 2042 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. Consistent with Executive Order 12866 guidance, we estimate the PV and EAV using 3 and 7 percent discount rates. The PV of the compliance costs, discounted at the 3-percent rate, is estimated to be about $14 billion, with an EAV of about $0.95 billion. At the 7-percent discount rate, the PV of the compliance costs is estimated to be about $10 billion, with an EAV of about $0.98 billion.

The EPA has developed a separate estimate of the projected compliance costs for the proposed standards for existing combustion turbines and third phase of the proposed standards for new natural gas-fired EGUs over the 2024 to 2042 period. The PV of these compliance costs, discounted at the 3-percent rate, is estimated to be between about $5.7 to 10 billion, with an EAV of between about $0.4 to 0.7 billion. At the 7 percent discount rate, the PV of these compliance costs is estimated to be between about $3.5 to 6.2 billion, with an EAV of about $0.34 to 0.6 billion.

Sections 3 and 8 of the RIA present detailed discussions of the compliance cost projections for the proposed requirements, as well as projections of compliance costs for less and more stringent regulatory options. For a detailed description of these compliance cost projections, please see sections 3 and 8 of the RIA. The EPA solicits comment on its cost estimation generally.

C. Economic and Energy Impacts

These proposed actions have economic and energy market implications. The energy impact estimates presented here reflect the EPA's illustrative analysis of the proposed rules. States are afforded flexibility to implement the proposed rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Table 9 presents a variety of energy market impact estimates for 2028, 2030, 2035, and 2040 for the illustrative proposal scenario, relative to the baseline. These results pertain to the analysis of the proposed standards for new combustion turbines and for existing steam generation EGUs, and do not include the impact of the proposed standards for existing combustion turbines and the third phase of the proposed standards for new combustion turbines.

TABLE 9—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE PROPOSAL SCENARIO, RELATIVE TO THE BASELINE

[Percent change]

	2028 (%)	2030 (%)	2035 (%)	2040 (%)
Retail electricity prices	−1	2	0	0
Average price of coal delivered to power sector	−1	0	2	2
Coal production for power sector use	−2	−40	−23	−15
Price of natural gas delivered to power sector	0	9	−2	−3
Price of average Henry Hub (spot)	0	10	−2	−2
Natural gas use for electricity generation	0	8	−1	−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 this rule 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.[702] 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

[702] 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.

performed a peer review of SAGE, and the review concluded in 2020.[703]

The EPA used SAGE to evaluate potential economy-wide impacts of these proposed rules, and the results are contained in an appendix of the RIA. As presented in the RIA, annualized social costs estimated in SAGE are approximately 35 percent larger than the partial equilibrium private compliance costs (less taxes and transfers) derived from IPM. This is consistent with general expectations based on the empirical literature.[704] However, the social cost estimate reflects the combined effect of the proposed rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the proposed rules. We are not able to identify their relative roles at this time. The EPA solicits comment on the SAGE analysis presented in the RIA appendix.

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 proposed actions are discussed more extensively in section 5 of the RIA.

D. Benefits

Pursuant to E.O. 12866, the RIA for these actions analyzes the benefits associated with the projected emission reductions under the proposals to inform the EPA and the public about these projected impacts.[705] These proposed rules are projected to reduce emissions of CO_2, SO_2, NO_X, and $PM_{2.5}$ nationwide which we estimate will provide climate benefits and public health benefits. The potential climate, health, welfare, and water quality impacts of these emission reductions 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 proposed standards and evaluate other costs in part to enable a comparison of costs and benefits pursuant to E.O. 12866, but we recognize there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified or monetized.

We estimate the climate benefits from these proposed rules using estimates of the social cost of greenhouse gases (SC–GHG), specifically the SC–CO_2. The SC–CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC–CO_2 includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–CO_2, therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions. In practice, data and modeling limitations naturally restrain the ability of SC–CO_2 estimates to include all the important physical, ecological, and economic impacts of climate change, such that the estimates are a partial accounting of climate change impacts and will therefore, tend to be underestimates of the marginal benefits of abatement. The EPA and other Federal agencies began regularly incorporating SC–GHG estimates in their benefit-cost analyses conducted under E.O. 12866 since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing CO_2 emissions in a rulemaking process.

We estimate the global social benefits of CO_2 emission reductions expected from the proposed rule using the SC–GHG estimates presented in the February 2021 TSD: *Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990.* These SC–GHG estimates are interim values developed under E.O. 13990 for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available climate science and economics. We have evaluated the SC–GHG estimates in the TSD and have determined that these estimates are appropriate for use in estimating the global social benefits of CO_2 emission reductions expected from this proposed rule. After considering the TSD, and the issues and studies discussed therein, the EPA finds that these estimates, while likely an underestimate, are the best currently available SC–GHG estimates. These SC–GHG estimates were developed over many years using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. As discussed in section 4 of the RIA, these interim SC–CO_2 estimates have a number of limitations, including that the models used to produce them do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate-change literature and that several modeling input assumptions are outdated. As discussed in the February 2021 TSD, the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) finds that, taken together, the limitations suggest that these SC–CO_2 estimates likely underestimate the damages from CO_2 emissions. The IWG is currently working on a comprehensive update of the SC–GHG estimates (under E.O. 13990) taking into consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, public comments received on the February 2021 TSD and other input from experts and diverse stakeholder groups. The EPA is participating in the IWG's work. In addition, 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 looking for opportunities to further improve SC–GHG estimation going forward. Most recently, the EPA has developed a draft updated SC–GHG methodology within a sensitivity analysis in the regulatory impact analysis of the EPA's November 2022 supplemental proposal for oil and gas standards that is currently undergoing external peer review and a public comment process. If EPA's updated SC–GHG methodology is finalized before these rules are finalized, the EPA intends to present monetized climate benefits using the updated SC–GHG estimates in the final RIA. See section 4 of the RIA for more discussion of this effort.

[703] U.S. EPA. 2020. Technical Review of EPA's Computable General Equilibrium Model, SAGE. EPA–SAB–20–010.

[704] See, for example, Marten, A.L., Garbaccio, R., and Wolverton, A. 2019. Exploring the General Equilibrium Costs of Sector-Specific Environmental Regulations. Journal of the Association of Environmental and Resource Economists, 6(6), 1065–1104.

[705] These results pertain to the analysis of the proposed standards for new combustion turbine EGUs and for existing steam-generating EGUs, and do not include the impact of the proposed standards for existing combustion turbine EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

In addition to CO_2, these proposed rules are expected to reduce emissions of NO_X and SO_2 and direct $PM_{2.5}$ nationally throughout the year. 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 ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects. These proposed rules are also expected to reduce ozone season NO_X emissions nationally. In the presence of sunlight, NO_X and volatile organic compounds (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, which is referenced in the RIA for these actions. 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 2042 period, discounted to 2024 in 2019 dollars, for the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs, which do not include the impact of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs. We monetize benefits of the proposed standards and evaluate other costs in part to enable a comparison of costs and benefits pursuant to E.O. 12866, but we recognize 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 $30 billion, with an EAV of about $2.1 billion using the SC–CO_2 discounted at 3 percent. The projected PV of monetized health benefits is about $68 billion, with an EAV of about $4.8 billion discounted at 3 percent. Combining the projected monetized climate and health benefits yields a total PV estimate of about $98 billion and EAV estimate of $6.9 billion.

At a 7 percent discount rate, these proposed rules are expected to generate projected PV of monetized health benefits of about $44 billion, with an EAV of about $4.3 billion discounted at 7 percent. The EPA notes that while OMB Circular A–4, as published in 2003, recommends using 3 percent and 7 percent discount rates as ''default'' values, Circular A–4 also recognizes that ''special ethical considerations arise when comparing benefits and costs across generations,'' and Circular A–4 acknowledges that analyses may appropriately ''discount future costs and consumption benefits . . . at a lower rate than for intragenerational analysis.'' Therefore, climate benefits remain discounted at 3 percent in this benefits analysis. Thus, these proposed rules would generate a PV of total monetized benefits of $74 billion, with an EAV of $6.4 billion discounted at a 7 percent rate.

The projected PV of monetized climate benefits for the analysis of the impact of the proposed standards for existing combustion turbines and the third phase of the proposed standards for new natural gas-fired EGUs is between about $10 to 20 billion, with an EAV of between about $0.7 to 1.4 billion using the SC–CO_2 discounted at 3 percent.

The results presented in this section provide an incomplete overview of the effects of the proposals. 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 proposed rules are not quantified. We anticipate that taking non-monetized effects into account would show the proposals to be more beneficial than the tables in this section reflect. Discussion of the non-monetized health, climate, welfare, and water quality benefits is found in section 4 of the RIA.

E. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

Consistent with the EPA's commitment to integrating environmental justice (EJ) in the Agency's actions, and following the directives set forth in multiple Executive Orders, the Agency has analyzed the impacts of these proposed rules on communities with potential environmental justice concerns and engaged with stakeholders representing these communities to seek input and feedback. The EPA evaluates, to the extent practicable, whether proposed GHG reductions are accompanied by changes in other health-harming pollutants that may place further burdens on these communities.[706]

Executive Order 12898 is discussed in section XV.J of this preamble and analytical results are available in section 6 of the RIA.

1. Introduction

Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples. Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through Federal government actions. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies''.[707] In recognizing that minority and low-income populations 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.

2. Analytical Considerations

EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, and 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

[706] These results pertain to the analysis of the proposed standards for new combustion turbine EGUs and for existing steam-generating EGUs, and do not include the impact of the proposed standards for existing combustion turbine EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

[707] Plan EJ 2014. Washington, DC: U.S. EPA, Office of Environmental Justice. *https://www.epa.gov/environmentaljustice/plan-ej-2014.*

regulatory option(s) under consideration?

3. For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?''

To address these questions, the EPA developed an analytical approach that considers the purpose and specifics of the rulemaking, as well as the nature of known and potential exposures and impacts. For the rules, the EPA quantitatively evaluates the proximity of existing affected facilities to potentially vulnerable and/or overburdened populations for consideration of local pollutants impacted by these rules but not modeled here (RIA section 6.4), as well as the distribution of ozone and $PM_{2.5}$ concentrations in the baseline and changes due to the proposed rulemakings across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, age, sex, educational attainment, and degree of linguistic isolation (RIA section 6.5). The EPA also qualitatively discusses potential EJ climate impacts (RIA section 6.3). Each of these analyses was performed to answer separate questions and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses provide information as to whether there may be potential EJ concerns associated with environmental stressors emitted from sources affected by the regulatory actions for certain population groups of concern. The baseline demographic proximity analyses examined the demographics of populations living within 5 km and 10 km of the following three sets of sources: (1) all 140 coal plants with units potentially subject to the proposed rules, (2) three coal plants retiring by January 1, 2032 with units potentially subject to the proposed rules, and (3) 19 coal plants retiring between January 1, 2032 to January 1, 2040 with units potentially subject to the proposed rules. The proximity analysis of the full population of potentially affected units greater than 25 MW indicated that the demographic percentages of the population within 10 km and 50 km of the facilities are relatively similar to the national averages. The proximity analysis of the 19 units that will retire from 1/1/32 to 1/1/40 (a subset of the total 140 units) found that the percent of the population within 10 km that is African American is higher than the national average. The proximity analysis for the 3 units that will retire by 1/1/32 (a subset of the total 140 units) found that for both the 10 km and 50 km populations the percent of the population that is Native American for one facility is significantly above the national average, the percent of the population that is Hispanic/Latino for another facility is significantly above the national average, and all three facilities were well above the national average for both the percent below the poverty level and the percent below two times the poverty level.

Because the pollution impacts that are the focus of these rules may occur downwind from affected facilities, ozone and $PM_{2.5}$ exposure analyses that evaluate demographic variables are better able to evaluate any potentially disproportionate pollution impacts of these rulemakings. The baseline $PM_{2.5}$ and ozone exposure analyses respond to question 1 from EPA's EJ Technical Guidance document more directly than the proximity analyses, as they evaluate a form of the environmental stressor primarily affected by the regulatory actions (RIA section 6.5). Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, and those less educated may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group, and American Indian populations and children may also experience disproportionately higher ozone concentrations than the reference group. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory actions for population groups of concern in the baseline (question 1).

Finally, the EPA evaluates how post-policy regulatory alternatives of these proposed rulemakings are expected to differentially impact demographic populations, informing questions 2 and 3 from EPA's EJ Technical Guidance with regard to ozone and $PM_{2.5}$ exposure changes. We infer that baseline disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternatives under consideration. This is due to the small magnitude of the concentration changes associated with these rulemakings across population demographic groups, relative to the magnitude of the baseline disparities (question 2). This EJ assessment also suggests that these actions are unlikely to mitigate or exacerbate $PM_{2.5}$ exposures disparities across populations of EJ concern analyzed. Regarding ozone exposures, while most policy options and future years analyzed will not likely mitigate or exacerbate ozone exposure disparities for the population groups evaluated, ozone exposure disparities may be exacerbated for some population groups analyzed in 2030 under all regulatory options. However, the extent to which disparities may be exacerbated is likely modest, due to the small magnitude of the ozone concentration changes (question 3). Importantly, the actions described in these proposals are expected to lower $PM_{2.5}$ and ozone in many areas, and thus mitigate some pre-existing health risks of air pollution across all populations evaluated.

3. Outreach and Engagement

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 and hydrogen, they may continue to face disproportionate burdens.

With regard to CCS, the EPA is proposing that CCS is a component of the BSER for new base load stationary combustion turbine EGUs, existing coal-fired steam generating units that intend to operate after 2040, and large and frequently operated existing stationary combustion turbine EGUs. The EPA recognizes and has given careful consideration to the various concerns that potentially vulnerable communities have raised with regard to the use of CCS in determining that CCS is BSER for these sources. In the following section, the EPA discusses various measures undertaken in this rulemaking and elsewhere to address community concerns on this matter.

One concern the EPA has heard from stakeholders is that adding CCS to EGUs can extend the life of an existing coal-fired steam generating unit, subjecting local residents who have already been negatively impacted by the operation of the coal-fired steam generating unit to additional harmful pollution. There are several important factors the EPA considered in evaluating the emission impact of an upgraded EGU when determining BSER for these units that intend to operate in the long term. First, CCS is the most effective add-on pollution control available for mitigation of GHG emissions from affected sources. Second, most CCS technologies work much more effectively when the EGU is emitting the lowest levels of SO_2 possible; therefore it is likely that as part of a CCS installation, companies will improve their EGUs' SO_2 control. Third, a CCS retrofit may trigger requirements under the major NSR program because of the potential for an emissions increase of one or more pollutants due to the additional energy production by the EGU to power the CO_2 capture system. If the source is undergoing major NSR permitting, the permitting authority would provide an opportunity for the public to comment on the draft permit, which is another avenue for affected residents to submit input regarding additional controls that may be needed to meet best available control technology requirements for non-GHG pollutants such as NO_X.[708]

Communities have also expressed concerns about CO_2 pipeline safety and geologic sequestration. As discussed in section VII.F.3.b.iii of the preamble, supercritical CO_2 pipeline safety is regulated by PHMSA. These regulations protect against environmental release during transport and PHMSA has announced steps to further strengthen its safety oversight of supercritical CO_2 pipelines, including initiating a new rulemaking to update standards for supercritical CO_2 pipelines and solicited research proposals to strengthen CO_2 pipeline safety.[709] Geologic sequestration of CO_2 is regulated by the EPA through the UIC Program under the Safe Drinking Water Act, and through the GHGRP under the Clean Air Act. UIC Class VI regulations include strong protections for communities to prevent contamination of underground sources of drinking water. These regulatory protections include a variety of measures, including proper site characterization and strict construction, operating, and monitoring requirements to ensure well and formation integrity, proper plugging of wells, and long-term project management and post-injection site care to ensure leakage prevention.[710] GHGRP requirements complement and build on UIC regulations through air-side monitoring and reporting requirements that provide the EPA and communities with a transparent means of evaluating the effectiveness of geologic sequestration. These programs work in combination to provide security and transparency.

The final concern the EPA has heard from stakeholders is about a lack of opportunity for impacted communities to voice opinions about projects like this that affect them. Recognizing the important stake that local residents have in decisions regarding EGUs in their communities, the EPA expects that states will address facility-specific concerns about how to responsibly deploy CCS and any other potential control strategies in the course of meaningful engagement under the proposed emission guidelines for existing steam generating units and existing combustion turbines, as discussed in section XII.F.1.b of the preamble. State plans should specifically ensure that community members have an opportunity to share their input if they reside near a fossil fuel-fired steam generating unit that plans to install CCS to meet the requirements of these proposed rules regarding how to responsibly deploy this technology.

With regard to the decision to construct a new combustion turbine, most of the safeguards outlined above for CCS retrofits apply. While meaningful engagement applies under emission guidelines to existing sources, there exists an opportunity for community engagement for new sources as part of the major NSR permitting process, in the event that the source triggers major NSR requirements. While new combustion turbines that co-fire with hydrogen may trigger major NSR, there are cases in which they are less likely to trigger major NSR, such as: (1) If the new combustion turbine is proposed at an existing facility and the facility is able to reduce its emissions more than the emissions increase from the combustion turbine (*e.g.,* if the combustion turbine replaces an existing coal-fired EGU and the facility has emission reduction credits from the shutdown unit), or (2) if the emissions from the new combustion turbine are low enough to not trigger major NSR.

The EPA further notes that hydrogen production presents a unique set of potential issues for vulnerable communities. During the February 27th National Tribal Energy Roundtable Webinar, one of the primary concerns articulated was the potential for fossil-derived hydrogen to essentially extend the life of petrochemical industries already creating localized pollution loading. Since hydrogen is non-toxic, and it does not produce carbon dioxide when burned, the inclusion of hydrogen in combustion turbine operations will lower overall health risks compared with hydrocarbons. Perceived community risks with hydrogen related to storage and transportation include its combustibility and propensity to leak due to extremely low molecular weight. Despite concerns about hydrogen, its low molecular weight ensures that it dissipates and disperses quickly when released outdoors, reducing unintended combustion risks compared with other fuels.[711] Adequate ventilation and leak detection are available to ensure safety and are important elements in the design of hydrogen systems. Concerns around hydrogen leaks can be mitigated with hydrogen monitoring systems combined with adequate ventilation and leak detection equipment, including special flame detectors.[712] Further, building and operational codes and standards developed specifically for hydrogen's properties can minimize risks around hydrogen usage in a community.[713]

New combustion turbine models designed to combust hydrogen, and those potentially being retrofit to combust hydrogen, may be co-located with electrolyzers that produce the hydrogen the facility will use. In such instances, water scarcity could be exacerbated in some areas by the freshwater demands of electrolytic hydrogen production, which could pose a particular challenge for vulnerable communities. As such, electrolyzer siting will need to take water availability into account. Examples for sustainable siting for electrolyzers are emerging in Europe, which has begun to employ Sustainable Value Methodology designed to be sensitive to water access and availability and includes, ''decision-making support, combining economic, environmental and social criteria''.[714] We also expect advances in electrolytic technology over time to reduce water demand, including the potential to enabling sea-water usage in electrolyzers.[715]

[708] The EPA discusses the interactions between CCS and non-GHG pollutants for existing coal-fired steam generating units in section X.D.1.a.iii(B) of this preamble.

[709] PHMSA, ''PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak.'' 2022. *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[710] *See generally* Administrator Michael S. Regan, Underground Injection Control Class VI Letter to Governors (December 9, 2022), *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[711] Department of Energy, Safe Use of Hydrogen *https://www.energy.gov/eere/fuelcells/safe-use-hydrogen.*

[712] Ibid.

[713] Department of Energy, Safety Codes and Standards *https://www.energy.gov/eere/fuelcells/safety-codes-and-standards-basics.*

[714] Journal of Cleaner Production, Volume 315, 15 September 2021, 128124, ''Water Availability and Water Usage Solutions for Electrolysis in Hydrogen Production'' Simoes, Sophia et al., *https://www.sciencedirect.com/science/article/pii/S0959652621023428.*

[715] Sun, F., Qin, J., Wang, Z. et al. Energy-saving hydrogen production by chlorine-free hybrid seawater splitting coupling hydrazine degradation. Nat Commun 12, 4182 (2021). *https://doi.org/10.1038/s41467-021-24529-3.*

F. Grid Reliability Considerations

The requirements for sources and states set forth in these proposed actions were developed cognizant of concerns about an electric grid under transition, and related reliability considerations. As previously stated, a variety of important influences have led to notable changes in the generation mix and expectations of how the power sector will evolve. These trends have generally put existing high-emitting generators under greater economic pressure and will continue to do so even absent any EPA action pursuant to CAA section 111, and that is manifest in various economic projections and modeling of the electric power system. Recent legislation, including the IIJA, the IRA, and State policies have amplified these trends, with continued change expected for the existing fleet of EGUs. Moreover, many regions of the country have experienced a significant increase in the frequency and severity of extreme weather events—events that are notably projected to worsen if GHG emissions are not adequately controlled. These events have impacted energy infrastructure and both the demand for and supply of electricity. A wide range of stakeholders including power generators, grid operators and State and Federal regulators are actively engaged in ensuring the reliability of the electric power system is maintained and enhanced in the face of these changes.

As explained in this preamble, these proposed actions take account of the rapidly evolving power sector and extensive input received from power companies and other stakeholders on the future of these regulated sources, while ensuring that new natural gas-fired combustion turbines and existing steam EGUs achieve significant and cost-effective reductions in GHG emissions through the application of adequately demonstrated control technologies. Preserving the ability of power companies and grid operators to maintain system reliability has been a paramount consideration in the development of these proposed actions. Accordingly, these proposed rules include significant design elements that are intended to allow the power sector continued resource and operational flexibility, and to facilitate long-term planning during this dynamic period. Among other things, these elements include subcategories of new natural gas-fired combustion turbines that allow for the stringency of standards of performance to vary by capacity factor; subcategories for existing steam EGUs that are based on operating horizons and fuel reflecting the request of industry stakeholders; compliance deadlines for both new and existing EGUs that provide ample lead time to plan; and proposed State plan flexibilities. In addition, this preamble discusses EPA's intention to exercise its enforcement discretion where needed to address any potential instances in which individual EGUs may need to temporarily operate for reliability reasons, and to set forth clear and transparent expectations for administrative compliance orders to ensure that compliance with these proposed rules can be achieved without impairing the ability of power companies and grid operators to maintain reliability. As such, these proposed rules provide the flexibility needed to avoid reliability concerns while still securing the pollution reductions consistent with section 111 of the CAA.

To support these proposed actions, the EPA has conducted an analysis of resource adequacy based upon power sector modeling and projections of the standards on existing steam generating units, and the first two phases of the standards on new combustion turbines, as well as the results of the spreadsheet-based analysis of the standards on existing combustion turbines and the third phase of the standards on new combustion turbines, that can be found in the RIA. Any potential impact of these proposed actions is dependent upon a myriad of decisions and compliance choices source owners and operators may pursue. It is important to recognize that the proposed rules provide multiple flexibilities that preserve the ability of responsible authorities to maintain electric reliability. While not explicitly modeled using IPM, the proposed emission guidelines for existing natural gas-fired EGUs are estimated to have very little incremental impact on resource adequacy. The guidelines would affect a subset of the total natural gas fleet, and units that install CCS are still able to maintain capacity accreditation values (after accounting for capacity de-rates). Moreover, units that operate below 50 percent capacity factor annually (and are not subject to the CCS requirement) would still be able to operate at higher levels during times of greater demand, thereby maintaining their capacity accreditation values.

The results presented in the *Resource Adequacy Analysis* TSD, which is available in the docket, show that the projected impacts of the proposed rules on power system operations, under conditions preserving resource adequacy, are modest and manageable. For the specific scenarios analyzed in the RIA, the implementation of the proposed rules can be achieved while maintaining resource adequacy even as shifts in existing and new capacity occur. Retirements are offset by additions, along with reserve transfers where/when needed, which demonstrates that ample compliance pathways exist for sources while preserving resource adequacy.

The EPA routinely consults with the DOE and FERC on electric reliability and intends to continue to do so as it develops and implements a final rule. This ongoing engagement will be strengthened with routine and comprehensive communication between the agencies under the DOE–EPA *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* signed on March 8, 2023.[716] The memorandum will provide greater interagency engagement on electric reliability issues at a time of significant dynamism in the power sector, allowing the EPA and the DOE to use their considerable expertise in various aspects of grid reliability to support the ability of Federal and State regulators, grid operators, regional reliability entities, and power companies to continue to deliver a high standard of reliable electric service. As the power sector continues to change and as the agencies carry out their respective authorities, the agencies intend to continue to engage and collectively monitor, share information, and consult on policy and program decisions to assure the continued reliability of the bulk power system.

In addition, the EPA observes that power companies, grid operators, and State public utility commissions have well-established procedures in place to preserve electric reliability in response to changes in the generating portfolio, and expects that those procedures will continue to be effective in addressing compliance decisions that power companies may make over the extended time period for implementation of these proposed rules. In response to any regulatory requirement, affected sources will have to take some type of action to reduce emissions, which will generally have costs. Some EGU owners may conclude that, all else being equal, retiring a particular EGU is likely to be the more economic option from the perspective of the unit's customers and/ or owners because there are better opportunities for using the capital than investing it in new emissions controls at

[716] *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* (March 8, 2023). *https://www.epa.gov/power-sector/electric-reliability-mou.*

the unit. Such a retirement decision will require the unit's owner to follow the processes put in place by the relevant RTO, balancing authority, or State regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. In some rare instances where the reliability of the system is jeopardized due to extreme weather events or other unforeseen emergencies, authorities can request a temporary reprieve from environmental requirements and constraints (through DOE) in order to meet electric demand and maintain reliability. These proposed actions do not interfere with these already available provisions, but rather provides a long-term pathway for sources to develop and implement a proper plan to reduce emissions while maintaining adequate supplies of electricity.

XV. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

These actions were submitted to the Office of Management and Budget (OMB) for review under Section 3(f)(1) of Executive Order 12866. 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 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,'' is available in the docket.

Table 10 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 proposed rule in 2019 dollars discounted to 2024. This analysis covers the impacts of the proposed standards for new combustion turbines and for existing steam generating EGUs, and does not include the impact of the proposed standards for existing combustion turbines and the third phase of the proposed standards for new combustion turbines. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the proposed rules.

The projected climate benefits in table 8 are based on estimates of the social cost of carbon (SC–CO_2) at a 3 percent discount rate and are discounted using a 3 percent discount rate to obtain the PV and EAV estimates in the table. 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 proposals from anticipated reductions in CO_2 emissions, the projected monetized health benefits include those related to public health associated with projected reductions in fine particulate matter ($PM_{2.5}$) and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the proposed requirements.

These results present an incomplete overview of the potential effects of the proposals 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 proposals to have a greater net benefit than this table reflects.

TABLE 10—PROJECTED MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE PROPOSED RULES, 2024 THROUGH 2042 [717]

[Billions 2019$, discounted to 2024] [a]

	3% Discount rate	7% Discount rate
Present Value:		
Climate Benefits [c]	$30	$30
Health Benefits [d]	68	44
Compliance Costs	14	10
Net Benefits [e]	85	64
Equivalent Annualized Value [b]:		
Climate Benefits [c]	2.1	2.1
Health Benefits [d]	4.8	4.3
Compliance Costs	0.95	0.98
Net Benefits [e]	5.9	5.4

[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 20-year period from 2024 to 2042.

[c] Climate benefits are based on changes (reductions) in CO_2 emissions. Climate benefits in this table are based on estimates of the SC–CO_2 at a 3 percent discount rate and are discounted using a 3 percent discount rate to obtain the PV and EAV estimates in the table. The EPA does not have a single central SC–CO_2 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC–CO_2 estimates (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). As discussed in section 4 of the RIA, consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

[717] This analysis pertains to the proposed standards for new combustion turbines and for existing steam generating EGUs and does not include the impact of the proposed standards for existing combustion turbines and the third phase of the proposed standards for new combustion turbines.

[d] The EPA notes that while OMB Circular A–4, as published in 2003, recommends using 3 percent and 7 percent discount rates as "default" values, Circular A–4 also recognizes that "special ethical considerations arise when comparing benefits and costs across generations," and Circular A–4 acknowledges that analyses may appropriately "discount future costs and consumption benefits . . . at a lower rate than for intragenerational analysis." Therefore, climate benefits remain discounted at 3 percent in this benefits analysis.

[e] The projected monetized health 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 3 and 7 percent.

[f] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits and are described in RIA Table 4–6.

As shown in table 10, the proposed rules are projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $30 billion, with an EAV of about $2.1 billion using the SC–CO_2 discounted at 3 percent. The proposed rules are also projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $68 billion, with an EAV of about $4.8 billion discounted at 3 percent.

The PV of the projected compliance costs are $14 billion, with an EAV of about $0.95 billion discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $85 billion and EAV of about $5.9 billion at a 3 percent discount rate.

At a 7 percent discount rate, the proposed rules are expected to generate projected PV of monetized health benefits of about $44 billion, with an EAV of about $4.3 billion. Climate benefits remain discounted at 3 percent in this net benefits analysis. Thus, the proposed rules would generate a PV of monetized benefits of about $74 billion, with an EAV of about $6.4 billion discounted at a 7 percent rate. The PV of the projected compliance costs are about $10 billion, with an EAV of $0.98 billion discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $64 billion and an EAV of about $5.4 billion discounted at 7 percent.

The EPA has developed a separate analysis of the proposed standards for existing combustion turbines and third phase of the proposed standards for new natural gas-fired EGUs over the 2024 to 2042 period. This analysis includes estimated compliance costs and climate benefits, and is located in Section 8 of the RIA. The PV of the compliance costs, discounted at the 3-percent rate, is estimated to be between about $5.7 to 10 billion, with an EAV of between about $0.40 to 0.70 billion. At the 7 percent discount rate, the PV of the compliance costs is estimated to be between about $ 3.5 to 6.2 billion, with an EAV of about $ 0.34 to 0.60 billion. The PV of the climate benefits, discounted at the 3-percent rate, is estimated to be between about $10 to 20 billion, with an EAV of between about $0.70 to 1.4 billion.

As discussed in section XIV of this preamble, the monetized benefits estimates provide an incomplete overview of the beneficial impacts of the proposals. In particular, the monetized climate benefits are incomplete and an underestimate as explained in section 4.2 of the RIA. In addition, important health, welfare, and water quality benefits anticipated under these proposed rules are not quantified or monetized. The EPA anticipates that taking non-monetized effects into account would show the proposals to have greater benefits than the estimates in the preamble and RIA reflect. Simultaneously, the estimates of compliance costs used in the net benefits analysis may provide an incomplete characterization of the true costs of the rule. The balance of unquantified benefits and costs is ambiguous but is unlikely to change the result that the benefits of the proposals exceed the costs by billions of dollars annually.

We also note that the RIA follows the EPA's historic practice of using a 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 Appendix B 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 proposed rules, including the full resource requirements of the expected compliance pathways, some of which are paid for through subsidies in the partial equilibrium analysis. The social cost estimates in the economy-wide analysis and discussed in Appendix B of the RIA are still far below the projected benefits of the proposed 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 proposed rule have been submitted for approval to the Office of Management and Budget (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.

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: $14,000 (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.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting "Currently under Review—Open for Public Comments" or by using the search function. OMB must receive comments no later than July 24, 2023.

3. 40 CFR Part 60, Subpart UUUUb

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (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.

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 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 104,000 hours at a total annual labor cost of $13.1 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 27,347 hours at a total annual labor cost of $1.8 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: 50.

Frequency of response: Once.

Total estimated burden: 104,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $13,163,689, includes $36,750 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.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' or by using the search function. OMB must receive comments no later than July 24, 2023.

4. 40 CFR Part 60, Subpart UUUUa

This proposed rule does not impose an information collection burden under the PRA.

C. Regulatory Flexibility Act (RFA)

I certify that these actions will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of the NSPS are private companies, investor-owned utilities, cooperatives, municipalities, and sub-divisions, that would seek to build and operate stationary combustion turbines in the future. The Agency has determined that seven small entities may be so impacted, and may experience an impact of 0 percent to 0.9 percent of revenues in 2035. Details of this analysis are presented in section 5.3 of the RIA.

The EPA started the Small Business Advocacy Review (SBAR) panel process prior to determining if the NSPS would have a significant economic impact on a substantial number of small entities under the RFA. The EPA conducted an initial outreach meeting with small entity representatives on December 14, 2022. The EPA sought input from representatives of small entities while developing the proposed NSPS which enabled the EPA to hear directly from these representatives about the regulation of GHG emissions from EGUs. The purpose of the meeting was to provide general background on the NSPS rulemaking, answer questions, and solicit input. Fifteen various small entities that potentially would be affected by the NSPS attended the meeting. The representatives included small entity municipalities, cooperatives, and industry professional organizations. When the EPA determined the NSPS would not have a significant economic impact on a substantial number of small entities under the RFA, the EPA did not proceed with convening the SBAR panel.

Emission guidelines will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish standards on existing sources, and it is those State requirements that could potentially impact small entities.

The analysis in the accompanying RIA is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their State implementation plans. *See American Trucking Assoc.* v. *EPA,* 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

The EPA is aware that there is substantial interest in the proposed rules among small entities and invites comments on all aspects of the proposals and their impacts, including potential impacts on small entities.

D. Unfunded Mandates Reform Act of 1995 (UMRA)

The proposed 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 proposed 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 XIV of this preamble and in the RIA.

The proposed 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 proposed 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 XV.B, but this burden is estimated to be below $100 million in any one year. As explained in section XII.F.6, the proposed emission guidelines do not impose specific requirements on Tribal governments that have designated EGUs located in their area of Indian country.

The proposed 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 rules 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. Subsequent to the September 22, 2022, meeting, the EPA received letters from five organizations. These letters were submitted to the pre-proposal non-rulemaking docket. See Docket ID No. EPA–HQ–OAR–2022–0723–0013, EPA–HQ–OAR–2022–0723–0016, EPA–HQ–OAR–2022–0723–0017, EPA–HQ–OAR–2022–0723–0020, and EPA–HQ–OAR–2022–0723–0021. For summary of the UMRA consultation see the memorandum in the docket titled, *Federalism Pre-Proposal Consultation Summary.*

E. Executive Order 13132: Federalism

The proposed NSPS and the proposed repeal of the ACE Rule do not have federalism implications. 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.

The EPA has concluded that the proposed emission guidelines may have federalism implications, because they may impose substantial direct compliance costs on State or local governments, and the Federal Government will not provide the funds necessary to pay these costs.

Any potential federalism implications arise from the provisions of CAA section 111(d)(1), which direct the EPA to ''prescribe regulations . . . under which each State shall submit to the [EPA] a [state] plan . . .'' establishing standards of performance for sources in the State. As discussed in the Supporting Statement found in the docket for this rulemaking, the development of State plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed emission guidelines, as well as time to work with State legislatures as appropriate, and develop a plan submittal.

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 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. Subsequent to the September 22, 2022, meeting, the EPA received letters from five organizations. These letters were submitted to the pre-proposal non-rulemaking docket. See Docket ID No. EPA–HQ–OAR–2022–0723–0013, EPA–HQ–OAR–2022–0723–0016, EPA–HQ–OAR–2022–0723–0017, EPA–HQ–OAR–2022–0723–0020, and EPA–HQ–OAR–2022–0723–0021. For a summary of the Federalism consultation see the memorandum in the docket titled *Federalism Pre-Proposal Consultation Summary.* A detailed Federalism Summary Impact Statement (FSIS) describing the most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final emission guidelines, as required by section 6(b) of Executive Order 13132. In the spirit of E.O. 13132, and consistent with EPA policy to promote communications between State and local governments, the EPA specifically solicits comment on these proposed actions from State and local officials.

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 proposed NSPS would impose requirements on owners and operators of new or reconstructed stationary combustion turbines and emission guidelines would 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 six fossil fuel-fired steam generating units located in Indian country but is not aware of any fossil fuel-fired steam generating units owned or operated by Tribal entities. The EPA notes that the proposed 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 proposed 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 stakeholder engagement.

The EPA will hold additional meetings with Tribal environmental staff to inform them of the content of these proposed rules as well as offer government-to-government consultation with Tribes. The EPA specifically solicits additional comment on these proposed rules from Tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks Populations and Low-Income Populations

Executive Order 13045 (62 FR 19885, April 23, 1997) directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. The EPA evaluated the health benefits of the CO_2, ozone and $PM_{2.5}$ emissions reductions and the results of this evaluation are contained in the RIA and are available in the docket. The EPA believes that the $PM_{2.5}$-related, ozone-related, and CO_2-related benefits projected under these proposed rules will improve children's health. Additionally, the $PM_{2.5}$ and ozone EJ exposure analyses in section 6 of the RIA suggests that nationally, children (ages 0–17) will experience at least as great a reduction in $PM_{2.5}$ and ozone exposures as adults (ages 18–64) in 2028, 2030, 2035 and 2040 under all regulatory alternatives of these rulemakings.

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 a significant adverse effect on the supply, distribution or use of energy. The EPA has prepared a Statement of Energy Effects for these action as follows. This analysis pertains to the proposed standards for new combustion turbines and for existing steam generating EGUs, and does not include the impact of the proposed standards for existing combustion turbines and the third phase of the proposed standards for new combustion turbines. The EPA estimates a 0.2 percent increase in retail electricity prices on average, across the contiguous U.S. in 2035, and a 28 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 decrease 2.4 percent in 2035. For more information on the estimated energy effects, please refer sections 5.1 and 8.3.3 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

These proposed actions involve 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 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 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 EPA welcomes comments on this aspect of the proposed rulemakings and, specifically, invites the public to identify potentially applicable VCS and to explain why such standards should be used in these regulations.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or Indigenous peoples) and low-income populations.

For new sources constructed after the date of publication of this proposed action under CAA section 111(b), the EPA believes that it is not practicable to assess whether the human health or environmental conditions that exist prior to this action result in disproportionate and adverse effects on people of color, low-income populations and/or Indigenous peoples, because the location and number of new sources is unknown.

For existing sources of this proposed action under CAA section 111(d), the EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations, and/or Indigenous peoples. The EPA believes that this proposed action is not likely to change disproportionate and adverse $PM_{2.5}$ exposure impacts on people of color, low-income populations, Indigenous peoples, and/or other potential populations of concern evaluated in the future analytical years. The EPA also believes that this proposed action is not likely to change disproportionate and adverse ozone exposure impacts on people of color, low-income populations, Indigenous peoples, and/or other potential populations of concern evaluated in 2028, 2035, and 2040. However, in the analytical year of 2030, this action is likely to slightly increase existing national level disproportionate and adverse ozone exposure impacts on Asian populations, Hispanic populations, and those linguistically isolated.

The EPA believes that it is not practicable to assess whether the GHG impacts associated with this action are likely to result in a change in disproportionate and adverse effects on people of color, low-income populations and/or Indigenous peoples. However, the EPA believes that the projected total cumulative power sector reduction of 617 million metric tons of CO_2 emissions between 2028 and 2042 will have a beneficial effect on populations at risk of climate change effects/impacts. Research indicates that some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the U.S. See sections VII, X, and XIV of this preamble for further information regarding GHG controls and emission reductions.

Michael S. Regan,

Administrator.

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