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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2025-0124; FRL-12674-02-OAR]

RIN 2060-AW55

Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this final rule, the U.S. Environmental Protection Agency (EPA) is repealing most provisions of the 2024 Carbon Pollution Standards for greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs) based on a reevaluation of the best system of emission reduction for the relevant subcategories. Specifically, the EPA is repealing the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines (*i.e.*, Phase 2 standards). In a separate action published concurrently with this final rule, the EPA is issuing a supplemental proposal soliciting comment on additional reasons to rescind all GHG emission requirements for fossil fuel-fired EGUs to effectuate the best reading of Clean Air Act (CAA) section 111 and ensure consistency with applicable principles of administrative law beyond those reasons on which the EPA solicited comment in the June 2025 notice of proposed rulemaking.

DATES: This final rule is effective on **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The approval of the Director of the Federal Register (FR) for incorporation by reference (IBR) of certain material listed in this rule expires as of **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].**

ADDRESSES: The EPA established a docket for this rulemaking under Docket ID No. EPA-HQ-OAR-2025-0124. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure statute restricts. The EPA does not place certain other material, such as copyrighted material, on the Internet; this material is publicly available only as portable document format (PDF) versions on the EPA computers in the docket office reading room. The public cannot download certain databases and physical items from the docket but may request these items by contacting the docket office at (202) 566-1744. The docket office has 10 business days to respond to these requests. With the exception of such material, publicly available docket materials are available electronically at *https://www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: For information about this final rule, contact U.S. EPA, Attn: Dr. Gregory Honda, Mail Drop: Industrial Processing and Power Division, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-2034; and email address: *honda.gregory@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this notice the use of “we,” “us,” or “our” refers 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]
AI	artificial intelligence
BSER	best system of emission reduction
Btu	British thermal units

Btu/kWh	British thermal units per kilowatt-hour
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CCS	carbon capture and sequestration/storage
CCUS	carbon capture, utilization, and storage
CFR	Code of Federal Regulations
CO_2	carbon dioxide
CPS	Carbon Pollution Standards
CPP	Clean Power Plan
CRA	Congressional Review Act
DOE	Department of Energy
EAV	equivalent annualized value
EGU	electric generating unit
EIA	Energy Information Administration
EO	Executive Order
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPAct05	Energy Policy Act of 2005
FEED	Front-End Engineering Design
FR	*Federal Register*
GHG	greenhouse gas
GW	gigawatt
ICR	information collection request
IGCC	integrated gasification combined cycle
IRC	Internal Revenue Code
lb	pound
MMBtu	million British thermal units
MMBtu/h	million British thermal units per hour
MW	megawatt
MWh	megawatt-hour
MWe	megawatt-equivalent
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
NPRM	notice of proposed rulemaking
NSPS	new source performance standards
NTTAA	National Technology Transfer and Advancement Act
OBBBA	One Big Beautiful Bill Act of 2025
OMB	Office of Management and Budget
PRA	Paperwork Reduction Act
PV	Present Value
RFA	Regulatory Flexibility Act
RIA	regulatory impact analysis
SO_2	sulfur dioxide
UIC	Underground Injection Control
UMRA	Unfunded Mandates Reform Act
U.S.C.	United States Code

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I. Executive Summary

In this final rule, the EPA is finalizing the repeal of most of the GHG standards promulgated in the 2024 Carbon Pollution Standards ("2024 CPS") for fossil fuel-fired power plants.[1] Specifically, the EPA is finalizing the repeal of the emission guidelines for existing fossil fuel-fired steam generating units, the CCS-based standards for coal-fired steam generating units undertaking a large modification, and the 2024 CCS-based standards for new base load stationary combustion turbines.

With this final action, the EPA addresses much of the regulatory uncertainty brought by the Agency's novel attempts to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. The EPA attempted to restrict GHG emissions from power plants for the first time in 2015, when the Agency issued both new source performance standards (NSPS) for new power plants ("2015 NSPS")[2] and emission guidelines for existing power plants (the Clean Power Plan ("2015 CPP")).[3]

In *West Virginia v. EPA*, the U.S. Supreme Court struck down[4] these efforts in large part, ruling that CAA section 111 does not authorize the EPA to adopt a regulatory scheme that "cap[s] carbon dioxide emissions at a level that will force a nationwide transition away from the use of coal to generate electricity."[5] Rather than change course, however, the EPA in 2024 promulgated a new rule that embraced the goals of the 2015 NSPS and 2015 CPP by expanding restrictions on certain new sources and regulating existing sources in a similar manner.

The EPA's most recent effort to regulate GHG emissions from the power sector, the 2024 CPS, includes standards of performance for new and reconstructed fossil fuel-

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[1] 89 FR 39798 (May 9, 2024).
[2] 80 FR 64510 (October 23, 2015).
[3] 80 FR 64662 (October 23, 2015).
[4] The Supreme Court stayed the 2015 CPP after the U.S. Court of Appeals for the D.C. Circuit declined to do so prior to merits briefing. West Virginia v. EPA, 577 U.S. 1126 (2016).
[5] 597 U.S. 697, 735 (2022).

fired combustion turbines and for certain modified fossil fuel-fired steam generating power plants, as well as rules directing States to set standards of performance for existing fossil fuel-fired steam generating power plants. During the rulemaking and subsequent litigation over the 2024 CPS, numerous States, regulated entities, and other stakeholders warned that these requirements are based on technologies that have not been adequately demonstrated, are unachievable, threaten to impose massive costs on the power sector, and do not adequately ensure the national interest in affordable, reliable electricity.

On January 20, 2025, President Trump issued Executive Order (EO) 14154, "Unleashing American Energy," which directs Federal agencies, including the EPA, to review existing regulations "to identify those agency actions that impose an undue burden on the identification, development, or use of domestic energy resources—with particular attention to oil, natural gas, coal, hydropower, biofuels, critical mineral, and nuclear energy resources."[6] The EO further affirms that it is "the policy of the United States to ensure that all regulatory requirements related to energy are grounded in clearly applicable law."[7] During the course of this review, the EPA has identified GHG emissions standards for power plants as one such action, including the 2024 CPS requirements that are the subject of this final rule.[8]

On February 19, 2025, President Trump issued EO 14219, "Ensuring Lawful Governance and Implementing the President's 'Department of Government Efficiency' Deregulatory Initiative," which directs Federal agencies, including the EPA, to identify and consider taking action to repeal "regulations that are based on anything other than the best reading of the underlying statutory authority or prohibition" and "regulations that implicate matters of social, political, or economic significance that are not authorized by

[6] 90 FR 8353 (January 20, 2025).
[7] *Id.*
[8] References to "GHG standards" here and elsewhere include NSPS promulgated under CAA section 111(b) and emission guidelines for existing sources promulgated under CAA section 111(d). *See* 42 U.S.C. 7411(b), (d).

clear statutory authority."[9] The EPA identified GHG emissions standards for power plants during the course of this review, including the 2024 CPS requirements that are the subject of this final rule.

On April 8, 2025, President Trump issued EO 14261, "Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241," which determined that "coal is essential to our national and economic security" and established "a national priority to support the domestic coal industry by removing Federal regulatory barriers that undermine coal production."[10] EO 14261 specifically found that "coal resources will be critical to meeting the rise in electricity demand due to the resurgence of domestic manufacturing and the construction of artificial intelligence data processing centers" and to increasing "energy supply," lowering "electricity costs," stabilizing the power grid, creating "high paying jobs," supporting "burgeoning industries," and assisting allies abroad.[11] Accordingly, EO 14261 directed the EPA, among other Federal agencies, to "identify any guidance, regulations, programs, and policies within their respective executive department or agency that seek to transition the Nation away from coal production and electricity generation" and "consider revising or rescinding Federal actions identified in subsection (a) of this section consistent with applicable law."[12] The EPA identified GHG emissions standards for power plants during the course of this review as well, including the 2024 CPS requirements that are the subject of this final rule and are estimated to result in mass closures of coal-fired power plants.

The EPA reviewed the GHG emissions standards for the power sector, as directed by EO 14154, EO 14219, and EO 14261, and has substantial concerns about the legal and technical underpinnings of the Agency's efforts to regulate GHG emissions from fossil

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[9] 90 FR 10583 (February 25, 2025).
[10] 90 FR 15517 (April 14, 2025).
[11] *Id.*
[12] *Id.*

fuel-fired power plants. Based on a reassessment of the legal and technical conclusions in the 2015 NSPS and 2024 CPS, the EPA issued a notice of proposed rulemaking in June 2025 ("June 2025 NPRM") that included both a primary proposal and an alternative proposal. The primary proposal would have repealed all GHG emissions standards for new and existing sources in the fossil fuel-fired EGU source category.[13] Specifically, the EPA proposed to determine that CAA section 111 requires the Agency to make a finding that GHG emissions from fossil fuel-fired power plants "cause[], or contribute significantly" to "air pollution which may reasonably be anticipated to endanger public health or welfare" (which we shorthand as "dangerous air pollution") as a predicate to regulating GHG emissions from those plants. The EPA further proposed to find that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. The EPA is not acting on those proposed determinations at this time and is instead concurrently issuing a supplemental proposal soliciting additional public comment on the underlying question raised in the primary basis of the June 2025 NPRM: Whether the EPA lacks statutory authority to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. Whereas the primary proposal in the June 2025 NPRM sought public comment on whether fossil fuel-fired EGUs "contribute significantly" to air pollution, the supplemental notice seeks public comment on the distinct question whether global climate change concerns satisfy the threshold requirement in CAA section 111(b)(1)(A) that fossil fuel-fired power plant emissions contribute significantly to "air pollution which may reasonably be anticipated to endanger public health or welfare."

The EPA's alternative proposal was based on the Agency's reexamination of the best system of emission reduction (BSER) determinations and associated requirements for fossil fuel-fired power plants in the 2024 CPS, which it undertook to ensure that all

[13] 90 FR 25752 (June 17, 2025).

regulatory requirements are grounded in applicable law. Under CAA section 111(a)(1), the EPA determines the BSER which, taking into account cost and any nonair quality and environmental impacts and energy requirements, has been adequately demonstrated. Based on the review of the BSER and associated requirement, the EPA proposed, in the alternative, to repeal parts of the 2024 CPS including the emission guidelines and other CCS-based requirements. As discussed below, the EPA is finalizing the alternative proposal repealing parts of the 2024 CPS and revising the associated BSER determinations as follows.

The EPA is finalizing the repeal of the emission guidelines for existing fossil fuel-fired steam generating units in their entirety. Specifically, the EPA is finalizing the determination that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units because 90 percent CCS has not been adequately demonstrated, the costs of 90 percent CCS are not reasonable, and the associated degree of emission limitation is not achievable. In a change from the 2024 CPS, the EPA concludes that previous projects that failed to achieve 90 percent CCS were not a sufficient basis to conclude the technology has been adequately demonstrated. Additionally, the carbon dioxide (CO_2) capture, pipeline, and sequestration infrastructure necessary to implement 90 percent CCS for the fleet of existing coal-fired steam generating units does not currently exist and would need to be broadly deployed. Because it is significantly unlikely that the necessary infrastructure for CCS can be deployed by the January 1, 2032 compliance date, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable.

The EPA is finalizing the determination that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units because 40 percent natural gas co-firing constitutes impermissible generation shifting under *West Virginia* and because the Agency erred in the 2024 CPS by construing *West Virginia* too narrowly in this respect. Additionally, a thorough consideration of the "energy requirements" BSER factor in CAA section 111(a)(1) shows that natural gas co-firing in a steam generating unit is an inefficient use of natural gas. Moreover, because it is unlikely that the necessary pipeline infrastructure can be deployed by the January 1, 2030 compliance date, the EPA is finalizing the determination that the degree of emission limitation is not achievable. Based on these conclusions, the EPA is repealing the requirements in the emission guidelines related to existing long-term and medium-term coal-fired steam generating units.

The EPA is also repealing the requirements in the emission guidelines related to natural gas- and oil-fired steam generating units. The EPA believes that requiring States to develop, submit, and implement plans solely for natural gas- and oil-fired steam generating units would be an inefficient use of State resources, as these sources comprise a relatively small part of the source category and the requirements under the 2024 emission guidelines for these sources would result in few or no emission reductions.

Furthermore, because the EPA is finalizing that 90 percent CCS has not been adequately demonstrated, the costs are not reasonable, and the degree of emission limitation is not achievable, the EPA is finalizing the repeal of the CCS-based requirements for coal-fired steam generating units undertaking a large modification.

The EPA is also finalizing that 90 percent CCS has not been adequately demonstrated and that the costs are not reasonable for new base load stationary combustion turbines. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA has determined that the phase 2 standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. The contrary determinations in the 2024 CPS appear to be in error for many of the same reasons that apply to existing coal-fired steam generating units. Consequently, the EPA is finalizing repeal of the phase 2 CCS-based requirements for new base load stationary combustion turbines.

The EPA solicited comment in general on the other GHG requirements for fossil fuel-fired EGUs and received comments suggesting that the 2024 efficiency-based standards (*i.e.*, the phase 1 standards) for new stationary combustion turbines are not achievable. However, the EPA is not revising or repealing those requirements in this final rule. The EPA acknowledges commenters' meritorious concerns regarding the 2024 efficiency-based standards for new stationary combustion turbines. While the EPA is not repealing or otherwise revising the 2024 efficiency-based standards in this final action, the Agency notes that it is concurrently issuing a supplemental proposal that, if finalized, would repeal all GHG standards for the fossil fuel-fired EGU source category under CAA section 111, including the 2024 efficiency-based standards in question. That action, if finalized as proposed, would resolve commenters' concerns.

A. Cost Savings

Over the 2026 to 2047 period, the present value (PV) of the estimated compliance cost savings for the power sector in 2024 dollars, discounted to 2025, is $160 billion using a three percent discount rate and $95 billion using a seven percent discount rate. Over this same period, the PV of the estimated real resource cost savings, which is the full avoided expenditure on physical and labor inputs used in the power sector for compliance, is $280 billion using a three percent discount rate and $180 billion using a seven percent discount rate discounted to 2025.[14] The cost savings do not account for

[14] The real resource cost savings account for the costs that society avoids paying as an outcome of the CPS requirements the EPA is repealing in this final rule. *See* Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units, available in the docket for this rulemaking (Document ID No. EPA-HQ-OAR-2025-0124).

benefits such as ensuring electric grid reliability and other secondary and tertiary benefits that cannot be monetized.

II. General Information

A. Where to Get a Copy of This Document and Other Related Information

In addition to the docket, an electronic copy of this final action will be on the Internet. Following signature by the Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power*. Following publication in the *Federal Register* (FR), the EPA will post the FR version at this same website.

B. Action Applicability

Fossil fuel-fired electric utility steam generating units and stationary combustion turbine EGUs that provide electricity to the electric grid (a utility power distribution system) comprise the source category that is subject to this action. The 2022 North American Industry Classification System (NAICS) code for the source category is 221112. The EPA does not intend this identification to be exhaustive but rather to provide a guide for readers regarding the entities that this final action is likely to affect.

The final repeal of 40 Code of Federal Regulations (CFR) part 60, subpart UUUUb, is applicable to States that, under the existing regulations, must develop and submit state plans pursuant to CAA section 111(d). The final repeal of 90 percent CCS-based requirements of 40 CFR part 60, subpart TTTTa, is applicable to affected facilities that began construction, reconstruction, or modification after May 23, 2023. This final action also affects Federal, State, local, and Tribal government entities that own and/or operate EGUs subject to 40 CFR part 60, subpart TTTTa, as affected facilities are no longer subject to requirements based on 90 percent CCS.

C. Statutory Authority

CAA section 111 authorizes the EPA to list and regulate a category of stationary sources if the Administrator, "in his judgment," finds that the source category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[15] The listing of a source category triggers the EPA's authority to promulgate "standards of performance" for new sources and, under limited circumstances, to prescribe regulations under which States submit plans that establish standards of performance for existing sources.[16] CAA section 111, along with agencies' authority to reconsider prior regulations, provides the statutory authority for this final action.[17]

1. Regulation of Emissions from New Sources

CAA section 111(b)(1)(A) authorizes the Administrator to publish, and from time-to-time revise, a list of categories of stationary sources that the Administrator, "in his judgment," finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Once the EPA lists a source category under CAA section 111(b)(1)(A), the EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for "new sources" in the source category. These standards are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to new sources within the relevant source category.

CAA section 111(a)(2) defines a "new source" as "any stationary source, the construction or modification of which is commenced after the publication of

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[15] 42 U.S.C. 7411(b)(1)(A).
[16] 42 U.S.C. 7411(b), (d).
[17] *See* FDA v. Wages & White Lion Invs., LLC, 604 U.S. 542, 568 (2025); FCC v. Fox TV Stations, Inc., 556 U.S. 502, 517-18 (2009); Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 41-42 (1983); *see also* Clean Air Council v. Pruitt, 862 F.3d 1, 8 (D.C. Cir. 2017) ("Agencies obviously have broad discretion to reconsider a regulation at any time.")

regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section, which will be applicable to such source." CAA section 111(a)(4) defines "modification" as "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, the EPA's regulations also treat a source that undergoes "reconstruction," by substantially replacing its components, as a new source.[18]

CAA section 111(a)(1) defines "standard of performance" as "a standard for emissions of air pollutants" that must be promulgated or revised in a specified manner. When the EPA establishes or revises a performance standard, CAA section 111(a)(1) provides that such a standard must "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." Thus, the term "standard of performance," as used in CAA section 111, makes clear that the EPA must determine both the "best system of emission reduction . . . adequately demonstrated" for emissions of the relevant air pollutants by regulated sources in the source category and the "degree of emission limitation achievable through the application of the [BSER]."[19] As explained elsewhere in this preamble, 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 adequately demonstrated systems, "taking into account" factors including "cost," "nonair quality health and environmental impact," and "energy requirements." The EPA has

[18] 40 CFR 60.15.
[19] *West Virginia*, 597 U.S. at 709.

discretion in determining the BSER, and has historically followed a "technology-based approach" that focuses on "measures that improve the pollution performance of individual sources," such as "add-on controls."[20] (If no system of emission reduction can be deemed adequately demonstrated in light of the EPA's consideration of these factors, then it may be the case that EPA cannot identify BSER).

After determining the BSER, the EPA derives the "degree of emission limitation achievable" through "application" of the BSER. A standard of performance is "achievable" if a technology can reasonably be projected to be available to an individual source at the time it is constructed so as to allow it to meet the standard.[21] The EPA must then, under CAA section 111(b)(1)(B), promulgate "standard[s] for emissions"—the NSPS—that reflect that level of stringency. The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER for emissions of the relevant air pollutants and may subcategorize sources accordingly pursuant to CAA section 111(b)(2).[22]

2. Regulation of Emissions from Existing Sources

The EPA has generally used CAA section 111 to establish standards for emissions of air pollutants from new sources within a category. In the rare instances where new stationary source standards concern air pollutant emissions that are not regulated under the National Ambient Air Quality Standards (NAAQS) program pursuant to CAA sections 108-110 or under the National Emission Standards for Hazardous Air Pollutants (NESHAP) program pursuant to CAA section 112, the statute provides a separate authority for addressing emissions of such air pollutants from existing sources in the source category.[23] In these limited circumstances, the

[20] *See id*. at 727 (quoting the 2015 CPP).
[21] Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 391 (D.C. Cir. 1973).
[22] 42 U.S.C. 7411(b)(2).
[23] 42 U.S.C. 7411(d)(1)(A)(i)-(ii).

promulgation of standards for new stationary sources triggers the EPA's authority to promulgate regulations for emissions of that pollutant from existing sources within the same category under CAA section 111(d).[24]

In contrast to the national regime for new sources under CAA section 111(b), CAA section 111(d) establishes a framework of "cooperative federalism for the regulation of existing sources."[25] CAA section 111(a)(6) defines an "existing source" as "any stationary source other than a new source." CAA section 111(d)(1) provides that when air pollutants covered by an NSPS for a source category are not already encompassed within the NAAQS program or NESHAP program, the EPA "shall prescribe regulations which shall establish a procedure similar to that provided by" CAA section 110 "under which each State shall submit to the Administrator" a plan for addressing emissions of such air pollutants by existing sources within such source category.[26] Reference to CAA section 110 incorporates the statute's provision for State submission and EPA review of state implementation plans (SIPs) that provide for the implementation, maintenance, and enforcement of the NAAQS for the areas within such State.[27] In a comparable manner, State plans required by the regulations authorized in CAA section 111(d) must "establis[h] standards of performance for any existing stationary source" for the air pollutant at issue and "provid[e] for the implementation and enforcement of such standards of performance."

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[24] *See West Virginia*, 597 U.S. at 710 ("Section 111(d) thus 'operates as a gap-filler,' empowering EPA to regulate harmful emissions not already controlled under the Agency's other authorities. . . . Reflecting the ancillary nature of Section 111(d), EPA has used it only a handful of times since the enactment of the statute in 1970.").
[25] Am. Lung Ass'n v. EPA, 985 F.3d 914, 931 (D.C. Cir. 2021), *rev'd in part sub nom. West Virginia*, 597 U.S. 697.
[26] 42 U.S.C. 7411(d)(1). CAA section 111(a)(6) defines an "existing source" as "any stationary source other than a new source." 42 U.S.C. 7411(a)(6).
[27] 42 U.S.C. 7410.

In the relatively few instances in which the EPA applies CAA section 111(d), the Agency generally promulgates regulations, termed "emission guidelines," that identify the BSER and the degree of emission limitation achievable through the application of the BSER. These regulations then require States to establish standards of performance for emissions of the air pollutant at issue by covered sources that reflect that level of stringency.[28] States need not compel regulated sources to adopt the particular components of the BSER itself. Rather, States have discretion in designing the policies and rules their sources will use to achieve the degree of emission limitation required by the emission guidelines. The statute also requires the EPA's regulations to 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."[29] Once the EPA approves a State's plan, its provisions become federally enforceable against the source in the same manner as the provisions of an approved SIP under the CAA.[30] If a State elects not to submit a plan or submits a plan that the EPA does not find "satisfactory," the CAA authorizes the Agency to promulgate a plan that establishes Federal standards of performance for the State's existing sources.[31]

3. Key Elements of Determining a Standard of Performance

Congress first defined the term "standard of performance" when enacting CAA section 111 in the 1970 CAA, amended the definition in the 1977 CAA Amendments, and amended the definition again in the 1990 CAA Amendments to largely restore the definition as in the 1970 CAA. The D.C. Circuit has reviewed CAA section 111

[28] As discussed below, CAA section 111(d)(1)(B) provides that, in certain circumstances, States may apply standards of performance that are less stringent than the degree of emission limitation that the EPA determines in the emission guidelines. *See* 42 U.S.C. 7411(d)(1)(B).
[29] 42 U.S.C. 7411(d)(1).
[30] 42 U.S.C. 7411(d)(2)(B).
[31] 42 U.S.C. 7411(d)(2)(A).

rulemakings on numerous occasions since the early 1970s and developed a body of case law that interprets the term.[32]

Whether promulgated by the EPA under CAA section 111(b) or established by the States under CAA section 111(d) in response to emission guidelines promulgated by the Agency, the basis for standards of performance is the "degree of emission limitation" that is "achievable" by sources in the source category by application of the "best system of emission reduction" that the EPA determines is "adequately demonstrated." As explained in this section, systems are not "adequately demonstrated" if they are "purely theoretical or experimental."[33] The D.C. Circuit has stated that in determining the "best" adequately demonstrated system for the pollutants at issue, the EPA must also take into account "the amount of air pollution" reduced.[34] The D.C. Circuit has also stated that the EPA may weigh the various factors identified in the statute and case law to determine the "best" system and has emphasized that the EPA has significant discretion in weighing the factors.[35]

After determining the BSER, the EPA sets an achievable emission limit based on application of the BSER.[36] For a CAA section 111(b) rule, the EPA determines the standard of performance that reflects that achievable emission limit. For a CAA section 111(d) rule, the States establish the standards of performance that reflect the degree of emission limitation that the EPA has included in an emission guideline. In applying these

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[32] *Am. Lung Ass'n*, 985 F.3d at 914; Delaware v. EPA, No. 13-1093 (D.C. Cir. May 1, 2015); Portland Cement Ass'n v. EPA, 665 F.3d 177 (D.C. Cir. 2011); Lignite Energy Council v. EPA, 198 F.3d 930 (D.C. Cir. 1999); Sierra Club v. Costle, 657 F.2d 298 (D.C. Cir. 1981); Essex Chem. Corp. v. Ruckelshaus, 486 F.2d 427 (D.C. Cir. 1973); *Portland Cement Ass'n*, 486 F.2d at 375.
[33] *Essex Chem. Corp.*, 486 F.2d at 433-34.
[34] *Sierra Club*, 657 F.2d at 326; *see id.* at 347 (stating that the EPA must take "technological innovation" into account).
[35] *Lignite Energy Council*, 198 F.3d at 933 ("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.").
[36] *See, e.g.*, 77 FR 49490, 49494 (August 16, 2012) (describing the three-step analysis in setting a standard of performance).

standards to existing sources, States are permitted to consider a source's remaining useful life and other factors.[37]

In identifying "system[s] of emission reduction," the EPA historically has followed a "technology-based approach" that focuses on "measures that improve the pollution performance of individual sources," such as "add-on controls."[38] In the 2015 CPP, the EPA significantly departed from its historical approach to standard setting under CAA section 111(b) by setting a BSER in which the "system" of emission reduction involved shifting electricity generation from one type of fuel to another. In *West Virginia*, the U.S. Supreme Court applied the major questions doctrine to hold that neither the term "system" nor any other provision of the CAA provided the requisite clear authorization to support the 2015 CPP's BSER, which the Court described as "carbon emissions caps based on a generation shifting approach"[39] that capped GHG "emissions at a level that will force a nationwide transition away from the use of coal to generate electricity[.]"[40] The Court explained that the EPA's BSER "forc[es] a shift throughout the power grid from one type of energy source to another," which constituted "unprecedented power over American industry" and was different in kind from the type of "system" of emission reduction envisioned by CAA section 111(d).[41]

To qualify as the BSER, the system of emission reduction must be "adequately demonstrated" as "the Administrator determines."[42] The plain text of CAA section 111(a)(1), and in particular the terms "adequately" and "the Administrator determines," confers upon the EPA the discretion to identify the appropriate system, including making scientific and technological determinations and considering a broad range of policy

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[37] 42 U.S.C. 7411(d)(1).
[38] *See West Virginia*, 597 U.S. at 727 (quoting 80 FR 64662, 64784 (October 23, 2015)).
[39] *Id*. at 732.
[40] *Id.* at 734.
[41] *Id*. at 728 (citation omitted).
[42] 42 U.S.C. 7411(a)(1).

considerations.[43] However, the terms "adequately" and "demonstrated," as well as applicable case law, make clear that the EPA may not determine that a "purely theoretical or experimental" system is "adequately demonstrated."[44] Moreover, applicable case law and the text and structure of CAA section 111, including the requirement that the resulting emission limitation be "achievable" and the eight-year review requirement in CAA section 111(b)(1)(B), place an outer bound on the EPA's discretion to project technological development into the future.

In addition, CAA section 111(a)(1) requires the EPA to account for "the cost of achieving [the emission] reduction" in determining the adequately demonstrated BSER. Although the CAA does not describe how the EPA should account for costs to affected sources, the D.C. Circuit has formulated the cost standard in various ways, including by stating on the upper bound that the EPA may not adopt a standard the cost of which would be "excessive" or "unreasonable."[45] The EPA has discretion in considering cost under CAA section 111(a), both in determining the appropriate level of costs and in balancing costs with other BSER factors.[46] The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance.[47]

Under CAA section 111(a)(1), the EPA must take into account "any nonair quality health and environmental impact and energy requirements" in determining the BSER. Nonair quality health and environmental impacts may include the impacts of the

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[43] Nat'l Asphalt Pavement Ass'n v. Train, 539 F.2d 775, 786 (D.C. Cir. 1976); *Essex Chem. Corp.*, 486 F.2d at 434.
[44] *Essex Chem. Corp.*, 486 F.2d at 433-34; *see Portland Cement Ass'n*, 486 F.2d at 391-92 (the EPA may not base an "adequately demonstrated" determination on a "'crystal ball' inquiry") (citation omitted).
[45] *Sierra Club*, 657 F.2d at 343; *see* 79 FR 1430, 1464 (January 8, 2014); *Lignite Energy Council*, 198 F.3d at 933 (costs may not be "exorbitant"); Portland Cement Ass'n v. Train, 513 F.2d 506, 508 (D.C. Cir. 1975) (costs may not be "greater than the industry could bear and survive").
[46] *Sierra Club*, 657 F.2d at 343.
[47] *See Essex Chem. Corp.*, 486 F.2d at 440; *Portland Cement Ass'n*, 486 F.2d at 387-88; *Sierra Club*, 657 F.2d at 313.

disposal of byproducts of the air pollution controls or requirements of the air pollution control equipment for water.[48] Energy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs.[49] In addition, based on the D.C. Circuit's interpretations of CAA section 111, energy requirements may also include the impact, if any, of the air pollution controls on the energy supply for a particular area or nationwide.[50] Furthermore, the EPA has considered under this statutory factor whether possible controls would create risks to the reliability of the national electricity system.[51]

The D.C. Circuit has also held that the term "best" authorizes the EPA to consider factors that further the purpose of the statute in addition to the ones enumerated in CAA section 111(a)(1). In particular, consistent with the plain language and the purpose of CAA section 111(a)(1), which requires the EPA to determine the "best system of *emission reduction*" (emphasis added), the D.C. Circuit has previously held that the Agency must consider the quantity of emissions at issue.[52] The EPA has broad discretion in determining which adequately demonstrated system of emission reduction is the "best." In *Sierra Club*, the D.C. Circuit explained that "section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS" 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 nonair quality environmental impacts and energy requirements.[53]

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[48] *Portland Cement Ass'n*, 486 F.2d at 387-88.

[49] For details on the modeled energy requirements associated with CCS, please see section 6.4 of the RIA for this final rule.

[50] *See Sierra Club*, 657 F.2d at 327-28 (quoting 44 FR 33580, 33583-84 (June 11, 1979)); 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club*, 657 F.2d at 351).

[51] *See, e.g.*, 89 FR 39886 (May 9, 2024).

[52] *Sierra Club,* 657 F.2d at 326. The D.C. Circuit has also held that Congress intended for CAA section 111 to create incentives for new technology, and therefore that the EPA is to consider technological innovation as one of the factors in determining the "best system of emission reduction." *See id.* at 346-47.

[53] *Sierra Club*, 657 F.2d at 319, 321; *see also* New York v. Reilly, 969 F.2d 1147, 1150 (D.C. Cir. 1992).

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 so as to allow the source to meet the standard.[54] The courts have established this approach for achievability in cases concerning CAA section 111(b) NSPS. A generally comparable approach applies to CAA section 111(d), although the BSER may differ in some cases between new and existing sources due to, for example, higher costs and feasibility of retrofit.[55] For existing sources, CAA section 111(d)(1) requires the EPA to establish regulations for State plans that, in turn, must include "standards of performance." As the Supreme Court has recognized, the EPA generally carries out this provision by promulgating emission guidelines that determine the BSER for a source category and then identify the degree of emission limitation achievable by application of the BSER.[56]

D. Severability

In this final rule, the EPA is repealing (1) the emission guidelines for existing fossil fuel-fired steam generating EGUs in 40 CFR part 60, subpart UUUUb; (2) the 90 percent CCS-based standards of performance for coal-fired steam generating units undertaking a large modification in 40 CFR part 60, subpart TTTT; and (3) the 90 percent CCS-based standards of performance for new base load stationary combustion turbines in 40 CFR part 60, subpart TTTTa. Although the record evidence supporting each of these separate actions may overlap, particularly pertaining to 90 percent CCS, the repeal of each is supported by its own, standalone rationale and is severable from the others. That is, the repeal of the emission guidelines for existing sources in subpart UUUUb does not impact the 90 percent CCS-based standards of performance for coal-fired steam

[54] *See Portland Cement Ass'n*, 486 F.2d at 391.
[55] *See, e.g.*, 40 FR 53340 (November 17, 1975).
[56] *See West Virginia*, 597 U.S. at 710; 40 CFR 60.21(e), 60.21a(e) (definition of "emission guideline" includes provision of the degree of emission limitation achievable through the application of the BSER as determined by the Administrator).

generating units undertaking a large modification and new base load stationary combustion turbines, as these rules apply to different sets of sources. Similarly, the repeal of the 90 percent CCS-based standards of performance either for modified sources or for new sources does not impact either of the two other rules. Again, while the records supporting each of these separate actions may overlap, application of the record evidence to each of the separate sets of regulated sources may yield different outcomes. If a court were to invalidate one or more of those actions, the EPA would still be able to implement the repeal of the remaining action or actions.

Additionally, within the group of existing fossil fuel-fired steam generating units (the sources regulated by 40 CFR subpart 60 subpart UUUUb), each of the following actions is severable: repeal of the BSER determination and associated requirements for the subcategory of long-term coal-fired steam generating EGUs, repeal of the BSER determination and associated requirements for the subcategory of medium-term coal-fired steam generating EGUs, and repeal of the requirements for the subcategory of oil- and natural gas-fired steam generating EGUs. That is, the repeal of the requirements for each separate subcategory of existing fossil fuel-fired steam generating units is based on an independent rationale and is severable from the repeal of the requirements for each other subcategory of existing units. If a court were to invalidate the EPA's action with regard to one or more subcategories of existing units, the Agency would still be able to implement the repeal of the requirements for the remaining subcategories or subcategory. This is because the requirements for each subcategory are self-contained in the regulations and, due to the design of the emission guidelines in subpart UUUUb, it would have been relatively difficult for sources to shift between subcategories. Thus, the repeal of the requirements for each subcategory of existing fossil fuel-fired steam generating units is severable.

E. Reliance Interests

The EPA requested comment on reliance interests on the 2015 NSPS and the 2024 CPS in the June 2025 NPRM that commenters believed the Agency should consider in formulating a final action.[57] Potentially significant and legitimate reliance interests may arise, for example, when regulated parties or other stakeholders expend resources to comply with existing standards, including by pricing compliance into costs for consumers. Significant and legitimate reliance interests may also arise when stakeholders reasonably factored the existence of standards into concrete plans that cannot be readily modified. Under relevant case law, these and other reliance interests may be a relevant consideration to weigh against competing rationales when deciding whether to change the Agency's position.[58] However, the EPA notes that general interests in retaining the at-issue 2024 CPS requirements for the sake of regulating GHG emissions from fossil fuel-fired power plants do not justify such retention in the absence of statutory authority and a reasoned basis for particular control requirements. To the extent the EPA is repealing aspects of the 2024 CPS based on applicable statutory requirements, the unlawful nature of those aspects necessitates repeal; the change-in-position doctrine does not expand an agency's statutory authority for the purpose of addressing reliance interests. Where possible and appropriate, the Agency considered whether any asserted reliance interests are significant and legitimate and, if so, whether different or additional regulatory actions could address such concerns, consistent with the requirements of the statute.[59]

The EPA carefully reviewed public comments to assess whether any aspects of this final action should be adjusted to account for reliance interests. The Agency received

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[57] 90 FR 25752, 25777 (June 17, 2025).
[58] *See, e.g.*, DHS v. Regents of Univ. of Cal., 591 U.S. 1, 30 (2020).
[59] The Agency also notes that because this final rule addresses certain requirements of the 2024 CPS only, we are not addressing any potential reliance interests on the 2015 NSPS at this time.

no comments on reliance interests arising from the 2024 CPS from regulated entities. To our knowledge, no expenditures on projects involving fossil fuel-fired power plants have been made exclusively in response to the 2024 CPS requirements that the EPA is repealing. The EPA notes that under the compliance dates and assumed project schedules for the two control strategies that served as the basis for requirements in the 2024 CPS concerning coal-fired power plants—90 percent CCS and 40 percent natural gas co-firing—affected sources would not yet have incurred significant expenditures. The compliance dates for these requirements, as well as the alternative compliance option of ceasing operations, were not scheduled to begin until 2032. Although, as discussed elsewhere in this preamble, the requirements involved a long implementation timeline and many fossil fuel-fired EGUs are subject to long planning horizons, much of the required buildout was anticipated to be on the part of third parties (pipeline infrastructure and injection wells, for example), and this rulemaking occurred far enough in advance to forestall the vast majority of sunk costs that would otherwise have been incurred. Based on information available to the Agency, such costs would have begun to accrue in earnest around the time of this final rule, making the action both timely and supporting reliance on the cost- and achievability-based rationales discussed herein.

Similarly, the EPA did not receive any comments from States on any resource expenditures they may have made to develop State plans in response to the emission guidelines for existing sources under 40 CFR Part 60, Subpart UUUUb. The EPA has not received any State plan submissions to date, and such plans were subject to extension opportunities and review that may have involved different timelines and further efforts in any event. Nor has the EPA promulgated a Federal plan in the absence of approved State plans, meaning air agencies have not expended resources participating in such a rulemaking or assisting regulated sources with compliance.

The EPA received one comment asserting State-related reliance interests, summarized below. However, upon careful examination, the EPA determined that this comment asserted general interests that are not properly understood as significant and serious reliance on the 2024 CPS that would warrant a different or additional regulatory outcome as to the 2024 CPS requirements at issue in this rulemaking. Therefore, the Agency is not aware of any substantial reliance interests that would have informed its decision making for purposes of this final action.

Comment: One commenter asserted that State and local air agencies are relying on potential non-GHG emission reduction co-benefits from the 2024 CPS to reach NAAQS attainment for criteria pollutants. The commenter asserted that State and local agencies have invested significant staff hours and funds in planning, outreach, modeling, and rule development to implement SIPs for NAAQS attainment. The commenter stated that the proposed repeal potentially required States to develop planning scenarios with and without the 2024 CPS. The commenter stated that State and local agencies must develop new attainment strategies and incur additional expenditures.

EPA Response: The EPA disagrees that State and local air agencies have reasonably relied on the at-issue 2024 CPS requirements to the extent that the impact of repeal on planning activities would amount to serious and irreversible harms. While the EPA acknowledges there may be overlaps between NAAQS attainment planning and the GHG control strategies that States would have had to develop under the 2024 CPS, these programs are governed by separate statutory provisions and address different pollutants on different timelines and under different regulatory paradigms. That is, while GHG control strategies States may have been developing pursuant to the 2024 CPS may have had co-benefits in terms of reductions of criteria air pollutants, we disagree that such co-benefits engender serious reliance interests relevant to this rulemaking because they do not justify retaining a GHG regulatory program that is not consistent with the relevant statutory requirements. This final action does not impact any of the EPA's criteria pollutant standards of performance for power plants regulated under and listed in various pre-2015 source categories pursuant to CAA section 111, which are more directly relevant to NAAQS attainment.

Moreover, the absence of comments raising resource expenditures related to State and local air agency implementation of the 2024 CPS emission guidelines suggests that air agencies have not, in fact, expended significant resources developing GHG control strategies because of the 2024 CPS. NAAQS attainment efforts are ongoing, and the projected criteria emission co-benefits in the 2024 CPS for the at-issue requirements are small in absolute terms. That is not surprising given the relatively long time horizon involved in developing such submissions and the short period of time that elapsed between finalization of the 2024 CPS and the announcement of reconsideration. To the extent the commenter asserts that State and local air agencies worked to develop options with and without the 2024 CPS, the Agency notes that such considerations are expected when analyzing the many options available to States in exercising their considerable discretion in developing strategies to attain and maintain the NAAQS and that requirements, particularly at the proposal stage, are necessarily subject to change.

While it is reasonable for States to consider the different control strategies they will be applying to their sources in a coordinated manner, the 2024 CPS requirements at issue could not have engendered serious reliance interests under the circumstances sufficient to warrant different or additional regulatory actions in this rulemaking. The Agency finalized the CPS in May 2024 and announced its intention to reconsider the rule in March 2025.[60] At the same time, NAAQS attainment planning has been ongoing, in

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[60] "Trump EPA Announces Reconsideration of Biden-Harris Rule, 'Clean Power Plan 2.0,'" That Prioritized Shutting Down Power Plants While Raising Costs on American Families" (March 12, 2025). Available at: https://www.epa.gov/newsreleases/trump-epa-announces-reconsideration-biden-harris-rule-clean-power-plan-20-prioritized.

many cases, for decades. It is therefore not likely that States could have relied on the existence of and obligations under the 2024 CPS for NAAQS attainment planning purposes. And, in all likelihood, State and local air agencies would necessarily have to take into consideration other developments in the electric power sector due to changes in, *e.g.*, electricity demand, such that they would be considering the adequacy of their NAAQS attainment planning even absent the repeal of the 2024 CPS requirements being finalized in this action. Moreover, it is a normal course of action for State and local air agencies to re-evaluate their planning in response to changes in Federal air regulations.

Considering these factors, the EPA believes that the commenter's concerns do not constitute a serious reliance interest warranting a different outcome. Such co-benefit considerations would not be an adequate basis to retain the at-issue 2024 CPS requirements, which must be justified under and consistent with statutory requirements with respect to the subject of the regulations (*i.e.*, GHG emissions). The 2024 CPS regulates GHG emissions in the form of CO_2 for the fossil fuel-fired EGU source category and the Agency did not, in the 2024 CPS, analyze or promulgate the at-issue requirements as multi-pollutant standards.

III. Background

A. EPA Regulation of GHG Emissions Under CAA Section 111

This section discusses the EPA's efforts to regulate GHG emissions under CAA section 111 since 2015, including the regulation of fossil fuel-fired EGUs, associated case law that is relevant to this action, and the EPA's asserted legal basis for regulating GHG emissions under CAA section 111.

The EPA has regulated air pollutants from power plants under CAA section 111 since 1971, when the Agency listed "fossil fuel-fired steam generators of more than 250 million British thermal units per hour (MMBtu/h) heat input" as a source category under

CAA section 111(b)(1)(A)[61] and subsequently promulgated NSPS for certain air pollutants.[62] In 1977, the EPA listed fossil fuel-fired “stationary gas turbines” in a category under CAA section 111(b)(1)(A)[63] and subsequently promulgated NSPS for certain air pollutants.[64] However, the EPA did not invoke CAA section 111 to regulate GHG emissions from power plants until 2015, when the Agency promulgated the 2015 NSPS, which addressed GHG emissions as measured by the equivalent of CO_2 emissions, from new fossil fuel-fired EGUs under CAA section 111(b);[65] and the 2015 CPP, which set emission guidelines directing States to regulate GHG emissions as measured by the equivalent of CO_2 emissions from existing EGUs under CAA section 111(d).[66]

In the 2015 NSPS, the EPA laid out a novel legal basis for regulating GHG emissions based on global climate change concerns under CAA section 111. Additionally, in that rule, the EPA asserted that the Agency was not required to make a finding of significant contribution under CAA section 111 before regulating GHG emissions. The EPA explained that CAA section 111(b)(1)(A) requires the Administrator to list any source category that “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” The EPA posited that, unlike other CAA provisions, CAA section 111(b)(1)(A) does not require the EPA to make endangerment and significant contribution findings for individual pollutants. Rather, the EPA asserted that once such findings are made for *any* pollutant emitted by a source category, the Agency has discretion to regulate *all* pollutants emitted by the source category subject only to rational basis constraints.[67]

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[61] 36 FR 5931 (March 31, 1971).
[62] *See, e.g.*, 36 FR 24876 (December 23, 1971); 40 CFR 60, subpart Da.
[63] *See* 42 FR 53657 (October 3, 1977).
[64] *See, e.g.*, 44 FR 62792 (September 10, 1979); 40 CFR 60, subpart KKKK.
[65] 80 FR 64510 (October 23, 2015).
[66] 80 FR 64662 (October 23, 2015).
[67] 80 FR 64510, 64529-30 (October 23, 2015).

Using this framework, the EPA created a new source category (*i.e.*, all fossil fuel-fired EGUs) consisting of the type of power plants previously listed in the 1970s under separate source categories. Specifically, the EPA took the step of "combining the steam generator and combustion turbine categories into a single category of fossil fuel-fired electricity generating units for purposes of promulgating standards of performance for GHG emissions."[68] The EPA explained that "[c]ombining the two categories is reasonable because they both provide the same product: Electricity services," and that combining the source categories in the 2015 NSPS was consistent with the Agency's decision to combine the categories "in the CAA section 111(d) rule for existing sources that accompanies [the 2015 NSPS]," *i.e.*, in the 2015 CPP.[69] The Agency maintained, however, that it was not listing a new source category and therefore was not required to make any endangerment or significant contribution finding for the fossil fuel-fired EGU source category to promulgate NSPS.

The EPA determined that it had a rational basis for concluding that emissions of CO_2 from fossil fuel-fired power plants merit regulation under CAA section 111. In reaching that conclusion, the Agency stated that it had determined in the 2009 Endangerment Finding that GHG emissions may reasonably be anticipated to endanger public health or welfare and that more recent information confirmed this determination. The EPA explained that the approach it was taking with regard to endangerment and GHG emissions from the fossil fuel-fired EGU source category was "substantially similar to that reflected in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider."[70] The EPA added that "the high level of GHG emissions from fossil fuel-

[68] *See id.* at 64531.
[69] *Id.*
[70] *Id.* at 64531; *see* 75 FR 49556 (August 13, 2010) (denying petitions for reconsideration of the 2009 Endangerment Finding).

fired EGUs makes clear that it is rational for the EPA to regulate GHG emissions from this sector."[71]

The EPA explained the legal basis for its interpretation of CAA section 111(b)(1)(A) as follows: The Agency noted that the EPA had listed fossil fuel-fired steam generators as a source category in 1971 and combustion turbines as a source category in 1979, in each case on the basis of the sources' emissions of non-GHG air pollutants, and the EPA acknowledged that the Agency had not considered GHG emissions at the time of those listings. Even so, in the 2015 NSPS, the EPA stated that the Agency interpreted CAA section 111 to provide that after the EPA listed a source category once, the CAA authorized the Agency to promulgate NSPS for any air pollutant from a source listed in that source category, so long as the EPA had a rational basis for doing so.[72]

The EPA received comments on the 2015 NSPS stating that CAA section 111 did not authorize regulation of GHGs from fossil fuel-fired EGUs until the Agency first makes a finding that emission of GHGs from these power plants contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA disagreed with those comments. The EPA took the position that CAA section 111(b)(1)(A), 111(b)(1)(B), and 111(a)(1), read together, authorize the Agency to regulate an air pollutant from a listed source category, subject to the standards of rationality under CAA section 307(d)(9)(A), and do not require the EPA to make an additional determination, as a predicate for regulation, that the air pollutant contributes significantly to dangerous air pollution.[73]

Notwithstanding the EPA's position in the 2015 NSPS that CAA section 111 does not require a pollutant-specific significant contribution finding for GHG emissions, the

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[71] 80 FR 64510, 64530 (October 23, 2015).
[72] *Id.* at 64529-31.
[73] Promulgation of NSPS under CAA section 111(b)(1)(B) is subject to the requirements of CAA section 307(d), under CAA section 307(d)(1)(C). *See* 42 U.S.C. 7607(d)(1)(C).

Agency purported to make, in the alternative, separate endangerment and significant contribution findings pursuant to CAA section 111(b)(1)(A) for GHG emissions from fossil fuel-fired EGUs. In doing so, the EPA asserted that the information and conclusions in the preamble to the 2015 NSPS provided a sufficient basis for such findings.[74] That is, the EPA took the position that regardless whether the Agency needed only a rational basis to regulate CO_2 emissions from fossil fuel-fired EGUs or was instead required to make new endangerment and significant contribution findings, we had made the requisite determinations based on the 2009 Endangerment Finding and the additional information presented in the preamble to the 2015 NSPS.

The 2015 NSPS promulgated standards of performance 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 integrated gasification combined cycle (IGCC) combustion turbines) and newly constructed and reconstructed stationary combustion turbines. These final standards are codified in 40 CFR part 60, subpart TTTT. In promulgating the 2015 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 2015 NSPS also 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

[74] 80 FR 64510, 64530-31 (October 23, 2015).

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 natural gas-fired stationary combustion turbines that operate at base load and non-base load, based on efficient natural gas combined cycle (NGCC) technology or the use of lower-emitting fuels (referred to as clean fuels in the 2015 NSPS) as the BSER. The EPA did not promulgate final standards of performance for modified stationary combustion turbines under CAA section 111(d) due to lack of information.

Petitioners challenged the 2015 NSPS in the D.C. Circuit, and the case has been held in abeyance over the years since in light of the EPA's subsequent rulemakings.

In the 2015 CPP—promulgated at the same time as the 2015 NSPS—the EPA interpreted CAA section 111(d) to require the Agency to regulate GHG emissions from existing sources in the newly combined source category because we had promulgated the 2015 NSPS for GHG emissions from new sources in that source category under CAA section 111(b).[75] The Agency noted that GHGs, and CO_2 in particular, are not separately regulated under the NAAQS program under CAA sections 107-110 or the NESHAP program under CAA section 112. The EPA determined that the BSER for existing fossil fuel-fired EGUs consisted primarily of generation shifting measures, as described in section II.C of this preamble.[76] The Supreme Court stayed the 2015 CPP pending review in February 2016,[77] and the D.C. Circuit held the litigation in abeyance and ultimately dismissed the challenges to the 2015 CPP in light of subsequent developments.[78]

[75] 80 FR 64662, 64702 (October 23, 2015).
[76] *Id.* at 64728-29.
[77] West Virginia v. EPA, 577 U.S. 1126 (2016).
[78] *Am. Lung Ass'n*, 985 F.3d at 937.

In 2018, following a change in administration, the EPA proposed to revise the NSPS for new, modified, and reconstructed fossil fuel-fired steam generating units and IGCC units (2018 NSPS Proposal).[79] The EPA proposed to revise the NSPS for newly constructed units based on a revised BSER of a highly efficient EGU without partial CCS. The EPA also proposed to revise the NSPS for modified and reconstructed units. The EPA never finalized the 2018 NSPS Proposal, and the Agency rescinded the proposal as part of the 2024 CPS.

In 2019, the EPA repealed the 2015 CPP and replaced that rulemaking with the Affordable Clean Energy (ACE) Rule.[80] In the ACE Rule, the Agency determined that the statutory "text and reasonable inferences from it" indicate that the best "system" of emission reduction as defined in CAA section 111(a)(1) "is limited to measures that can be applied to and at the level of the individual source," meaning the BSER must be control measures for reducing emissions at individual sources.[81] The Agency concluded that generation shifting is not such a control measure.[82] In addition, the EPA further concluded that the 2015 CPP was a "major rule" subject to the major questions doctrine and therefore must be supported by "a clear statement from Congress." Because the statutory phrase "best system of emission reduction" does not clearly speak to generation shifting, the Agency reasoned that CAA section 111 should not be read to encompass generation-shifting measures.[83] To replace the 2015 CPP, the EPA promulgated as part of the ACE Rule a new set of emission guidelines for existing coal-fired steam-generating EGUs.[84] In these new emission guidelines, the EPA determined the BSER for existing coal-fired EGUs to be heat rate improvements alone. Specifically, the EPA listed various

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[79] 83 FR 65424 (December 20, 2018).
[80] 84 FR 32520 (July 8, 2019).
[81] *See id.* at 32523-24.
[82] *See id.* at 32546.
[83] *See id.* at 32529.
[84] *See id.* at 32532.

technologies that could improve heat rate and identified the "degree of emission limitation achievable" by providing ranges of expected emission reductions associated with each of the technologies.[85] The EPA also explained that we were not determining CCS as the BSER in part because of unreasonable expense and was not determining natural gas co-firing as the BSER because co-firing was an inefficient use of natural gas.[86]

In 2021, a divided panel of the D.C. Circuit vacated the ACE Rule, including the repeal of the 2015 CPP.[87] The panel majority held, among other things, that CAA section 111 did not limit the EPA, in determining the BSER, to measures applied at and to an individual source and that CAA section 111 authorized the Agency to determine generation shifting is the BSER. The panel majority also rejected in the argument that generation-shifting implicated "the so-called 'major questions' doctrine" based on its interpretation of the Supreme Court's decisions in *Massachusetts* and *AEP*.[88] As a result, the D.C. Circuit vacated both the repeal of the 2015 CPP and the ACE Rule.[89] The court did not address most other challenges to the ACE Rule, including the arguments concerning the heat rate improvement BSER.

Several petitioners argued that the ACE Rule was invalid on the grounds that the EPA had predicated regulation of GHG emissions from existing EGUs on the new source GHG emissions standards in the 2015 NSPS. In addition, petitioners argued that those standards were flawed because CAA section 111 required them to be predicated on a pollutant-specific significant contribution finding with identified standards or criteria for

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[85] *Id.* at 32535-38.
[86] *Id.* at 32545.
[87] *Am. Lung Ass'n*, 985 F.3d at 914.
[88] *Id.* at 959.
[89] *Id.* at 995. In a partial dissent, Judge Walker argued that the 2015 CPP (and aspects retained in the 2019 ACE Rule) violated the major questions doctrine because CAA section 111 does not include a clear statement of authority to regulate GHG emissions from power plants. *Id.* at 995-1003.

determining significance. The D.C. Circuit held that it did not need to decide whether CAA section 111 requires a pollutant-specific significant contribution finding for GHG emissions from EGUs as a predicate for CAA section 111 regulation because the EPA had made such a finding in the alternative. The court rejected the petitioners' argument that the significant contribution finding was flawed due to lack of identified criteria for significance and explained that the magnitude of GHG emissions from EGUs supported the significance finding without identified criteria for significance.[90]

In 2022, the U.S. Supreme Court in *West Virginia* reversed the D.C. Circuit's decision to vacate the ACE Rule's embedded repeal of the 2015 CPP.[91] As noted in section II.C of this preamble, the Supreme Court concluded that the 2015 CPP's BSER of "generation shifting" implicated the major questions doctrine and exceeded the EPA's statutory authority because CAA section 111 does not clearly authorize the Agency to regulate GHG emissions in a manner that forces a nationwide transition away from using coal to generate electricity.[92]

Following the U.S. Supreme Court's decision in *West Virginia*, the EPA informed the D.C. Circuit that the Agency intended to replace the ACE Rule.[93] On October 27, 2022, the D.C. Circuit took the necessary steps to, among other things, respond to the Supreme Court's decision by ensuring that the 2015 CPP remained repealed and stay further proceedings with respect to the challenges to the ACE Rule given the EPA's plans to replace that rule.[94]

[90] *Id.* at 974-77.
[91] *West Virginia*, 597 U.S. 697.
[92] *Id*. at 734-35.
[93] Am. Lung Ass'n v. EPA, D.C. Cir. No. 19-1140, Motion to Govern, Doc. #196782 (October 3, 2022).
[94] Am. Lung Ass'n v. EPA, D.C. Cir. No. 19-1140, Order, Doc. #1970895 (October 27, 2022).

B. Carbon Pollution Standards

On May 9, 2024, the EPA promulgated the CPS, which consisted of several separate actions.[95] The first action was the repeal of the ACE Rule. The EPA explained, among other things, that the suite of heat rate improvements that was identified in the ACE Rule as the BSER is not an appropriate BSER for existing coal-fired EGUs.[96]

In addition, the 2024 CPS included emission guidelines for GHG emissions from existing fossil fuel-fired steam generating units, which include the separate subcategories of coal-fired units, oil-fired units, and gas-fired units.[97] For long-term coal-fired units, the EPA finalized 90 percent CCS as the BSER, with a presumptive standard of an 88.4 percent reduction in annual emission rate and a compliance deadline of January 1, 2032. The EPA asserted that 90 percent CCS is an adequately demonstrated technology that achieves significant emissions reduction and that costs are reasonable, considering the supposedly declining costs of the technology and the Internal Revenue Code (IRC) section 45Q tax credit available for a certain number of years to generating sources that use CCS technology. In recognition of the significant capital expenditures involved in deploying CCS and previously announced retirement dates for several coal-fired steam generating units, the EPA finalized a separate subcategory for existing coal-fired units that demonstrate that they plan to permanently cease operation before January 1, 2039. For this subcategory, the BSER is co-firing with natural gas at a level of 40 percent of the unit's annual heat input, the presumptive standard is a 16 percent reduction in annual emission rate, and the compliance deadline is January 1, 2030. In addition, the EPA exempted existing coal-fired units that demonstrate that they plan to permanently cease

[95] 89 FR 39798 (May 9, 2024).
[96] In the CPS, the EPA also withdrew the separate proposed revisions to the New Source Review (NSR) regulations that were included the ACE Rule proposal. *See* 83 FR 44746, 44773-83 (August 31, 2018).
[97] Although the EPA also proposed emission guidelines for GHG emissions from existing fossil fuel-fired combustion turbines in the proposed CPS, the Agency did not finalize those emission guidelines.

operation prior to January 1, 2032. The EPA determined that these controls were cost-effective primarily by reference to two metrics used in prior rulemakings. The first metric determines the annualized cost in dollars for each ton, or other quantity, of the regulated air pollutant removed through the system of emission reduction. The second metric, which the EPA particularly relied on in rules for the electric power sector, determines the annualized cost of controls relative to the electricity generated by the EGU in dollars per megawatt-hour ($/MWh) of generation.[98]

For existing natural gas- and oil-fired steam generating units, the EPA further subcategorized them into base load (units with annual capacity factors greater than or equal to 45 percent), intermediate load (units with annual capacity factors greater than or equal to eight percent and less than 45 percent), and low load (units with annual capacity factors less than eight percent) subcategories. The EPA finalized routine methods of operation and maintenance as the BSER for base load and intermediate load units, with presumptive standards for base load units of 1,400 pounds (lb) CO_2/MWh-gross, and for intermediate load units of 1,600 lb CO_2/MWh-gross.[99] For low load units, the EPA finalized a uniform fuels BSER and a presumptive input-based standard of 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources.

The 2024 CPS also included standards of performance for new and reconstructed combustion turbines organized into three subcategories: base load, intermediate load, and low load. For base load turbines, the standard consisted of two components in two phases. The first component is based on a BSER of highly efficient generation (which was determined based on the emission rates achieved by the best performing units), and

[98] 89 FR 39798, 39882 (May 9, 2024).
[99] “Gross” refers to the electricity generated by the EGU, as opposed to “net,” which is equivalent to the electricity delivered to the grid and accounts for the loss due to the electricity used by auxiliary equipment at the facility.

the EPA required compliance with this first component upon the effective date of the 2024 CPS. The second component is based on a BSER of 90 percent CCS, and the EPA required compliance with this second component on January 1, 2032. For intermediate load turbines, the EPA determined that highly efficient simple-cycle generation is the BSER. For low load combustion turbines, the EPA determined that the use of lower-emitting fuels is the BSER.

In addition, the EPA revised the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.*, a modification that increases the hourly emission rate of the source by more than 10 percent) to be based on the BSER of 90 percent CCS. Finally, the EPA withdrew the 2018 NSPS Proposal for GHG emissions from coal-fired EGUs.[100]

Following promulgation of the 2024 CPS, many States and industry groups filed petitions for review in the D.C. Circuit, and many subsequently filed motions to stay the rule. The D.C. Circuit denied the stay motions on July 19, 2024,[101] and the Supreme Court denied these motions on October 16, 2024.[102] Justice Thomas would have granted a stay, and Justice Kavanaugh, joined by Justice Gorsuch, wrote that "the applicants have shown a strong likelihood of success on the merits as to at least some of their challenges to the [EPA's] rule."[103] The parties briefed the merits, and the D.C. Circuit held oral argument on December 6, 2024. Following a change in administration, the D.C. Circuit agreed to hold the case in abeyance pending further actions by the Agency.

C. Changes in Trends in Fossil Fuel-fired EGUs

In the 2024 CPS, the historical data that supported the analysis that the EPA conducted and relied on to assess the rule's projected impacts showed only incremental

[100] 83 FR 65424 (December 20, 2018).
[101] West Virginia v. EPA, D.C. Cir. No. 24-1120, Order, Doc. #2065493 (July 19, 2024).
[102] West Virginia v. EPA, 145 S. Ct. 2 (2024).
[103] *Id.*

increases in electricity demand: a 13 percent increase between 2000 and 2022, with demand remaining relatively flat from 2007 to 2022. At the same time, the share of coal-fired electricity decreased in both relative and absolute terms, declining 58 percent and going from delivering 52 percent of total net generation in 2000 to 19 percent in 2022. Natural gas-fired net generation increased by 181 percent over this period, delivering 39 percent of net generation in 2022. The combination of wind and solar net generation grew 172 percent over this period, delivering 15 percent of total net generation in 2022. Natural gas surpassed the total net generation from coal on an absolute basis in 2016, and renewables surpassed the total net generation from coal on an absolute basis in 2022.[104] The information that the EPA analyzed for purposes of the 2024 CPS indicated that the sector trend of moving away from coal-fired generation was likely to continue, the share of electricity generation from natural gas-fired sources would likely decline, and the share of generation from non-emitting technologies would likely continue to increase. In the 2024 CPS, the EPA anticipated that the recent trend of retirements of coal-fired capacity (at an average annual rate of 10 gigawatt (GW) from 2015 to 2023) would continue due to the economics of coal-fired generation. At the time of the 2024 CPS final rule, more than half of the coal-fired steam generating units in operation had announced that they would retire or convert to natural gas by 2039.[105]

In contrast, updated information and analysis of power sector trends indicates a significantly different landscape moving forward. As noted in the June 2025 NPRM, the EPA believes that coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply due to increasing

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[104] Power Sector Trends Technical Support Document 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 at 5-6, Document ID No. EPA-HQ-OAR-2023-0072-8920.
[105] 89 FR 39798, 39816-18 (May 9, 2024).

electricity demand.[106] Several key factors play major roles in reshaping projections of electricity markets over the coming decades. Demand growth across the U.S. is significantly higher than prior estimates. According to the 2024 North American Electric Reliability Corporation (NERC) Long Term Reliability Assessment, peak demand remained static nationwide over the ten-year period from 2013 through 2022.[107] In 2022, NERC projected a 0.65 percent compound annual growth rate for summer peak demand based on the ten-year period of 2022 through 2031.[108] In contrast, in late 2024, NERC projected a 1.67 percent compound annual growth rate for summer peak demand based on the ten-year period of 2025 through 2034.[109] Increasing amounts of large commercial and industrial loads, particularly those related to data center demand for artificial intelligence (AI) applications, are primarily driving this nearly 2.6-fold increase in projected growth rates. Sub-nationally, these impacts are even more striking. The Electric Reliability Council of Texas' (ERCOT) 2025 long-term load forecast projects summer peak demand rising at an 8.9 percent annual growth rate based on the six-year period of 2025 to 2031.[110] The 2025 long-term load forecast for PJM, a regional transmission organization serving large parts of the eastern US, projects a 3.1 percent annual growth rate in summer peak demand based on the ten-year period of 2025 to 2035.[111] NERC concludes that critical reliability challenges face the sector when considering the need to meet this higher level of demand, manage ongoing thermal retirements, and develop

[106] *See* 90 FR 25752, 25772, 25774 (June 17, 2025).
[107] NERC 2023 Long-Term Reliability Assessment (December 2024). Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.
[108] NERC 2021 Long-Term Reliability Assessment (December 2022). Available at: https://www.nerc.com/our-work/assessments/past-reliability-assessments.
[109] NERC 2023 Long-Term Reliability Assessment (December 2024). Available at: https://www.nerc.com/our-work/assessments/past-reliability-assessments.
[110] ERCOT. 2025 System Planning Long-term Hourly Peak Demand and Energy Forecast. Available at: https://www.ercot.com/files/docs/2025/04/08/2025_LTLF_Report.docx.
[111] PJM. 2025 Long-Term Load Forecast Report. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.

additional transmission and support resources.[112] A recent Department of Energy (DOE) report, which examines reliability implications of ongoing thermal retirements in the face of projected increases in electricity demand, echoes these findings and further states that the risk of power outages may increase by a hundred fold in some instances if firm resources continue to retire in the face of projected load growth.[113]

The passage of the One Big Beautiful Bill Act of 2025 (OBBBA) will also have important impacts on the power sector. The phaseout of tax subsidies to wind and solar resources will likely reduce incremental builds of these technologies, particularly after 2028. This, in turn, will further increase the need for retaining existing thermal resources (including coal-fired steam generating units) and building new thermal (including new combustion turbines) resources to help meet increasing electricity demand. Considering these changes, the EPA expects the OBBBA to produce a net effect of reducing factors that boosted the economic competitiveness of wind and solar resources and improving the economic competitiveness of thermal generation (including coal and natural gas-fired generation).

Moreover, higher levels of electricity demand result in greater demand for around-the-clock power, which results in a higher utilization of coal- and gas-fired resources in the EPA's current analysis than in the EPA's 2024 analysis underpinning the 2024 CPS.[114] The trends the EPA has incorporated into the updated analysis result in projections that show total electricity generation will increase by approximately 15

[112] NERC 2023 Long-Term Reliability Assessment (December 2024). Available at: https://www.nerc.com/our-work/assessments/past-reliability-assessments
[113] U.S. Department of Energy, Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid (2025). Available at: https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[114] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).

percent by 2030 and 25 percent by 2035,[115] significantly higher than projections in the 2024 analysis for the 2024 CPS.[116]

This recent change in demand for around-the-clock power already is effecting changes in the current market, as shown by a number of coal-fired steam generating units that are delaying or canceling their scheduled retirements due to increased electricity demand.[117] Using the latest available data from the Energy Information Administration (EIA), in 2024, the U.S. power sector had approximately 174 GW of coal-fired EGUs that collectively consumed approximately 7.0 quadrillion British thermal units (Btus) of energy. According to data reported by the owners and operators of coal-fired capacity, the EIA expects 146 GW of this capacity to remain in service through 2032. In addition, the EIA now expects 24.5 GW of combined cycle additions and 11.5 GW of combustion turbine additions over the next five years,[118] demonstrating a sharp increase from the August 2023 EIA data underlying the analysis of the 2024 CPS, which cited roughly 9.6 GW of combined cycle and 1.9 GW of combustion turbine additions planned for construction between 2025 and 2030.[119]

The EPA's updated projections reflect these changes.[120] As a specific example, at the end of 2024, 174 GW of coal-fired EGUs were active in the power sector

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[115] *Id.*
[116] U.S. EPA. Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (May 2024). Document ID No. EPA-HQ-OAR-2023-0072-8913.
[117] Power. U.S. Coal Plants Get Reprieve as Market and Policies Change. Available at: https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change.
[118] U.S. Energy Information Administration. EIA Power Monthly (October 2025). Available at: https://www.eia.gov/electricity/data/eia860m/xls/october_generator2025.xlsx.
[119] U.S. Energy Information Administration. EIA Power Monthly (August 2023). Available at: https://www.eia.gov/electricity/data/eia860m/xls/august_generator2023.xlsx.
[120] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).

nationwide.[121] In the 2024 CPS, the EPA projected that, in the baseline absent requirements, approximately 40 GW of existing coal capacity would still be active by 2040.[122] However, the EPA has revisited the 2024 baseline in light of the information above. The EPA now projects that, absent the requirements of the 2024 CPS, approximately 100 GW of coal capacity would be active in 2040,[123] more than twice the capacity EPA previously projected. Similarly, in the 2024 CPS, the EPA projected approximately 26 GW of incremental NGCC capacity additions by 2035.[124] The EPA now projects, absent the requirements of the 2024 CPS, approximately 155 GW of new NGCC capacity by 2035. Based on the EPA's updated projections, informed by the recent and consequential changes in the electricity market, a much larger number of EGUs would be subject to the requirements of the 2024 CPS than previously estimated for the purposes of that rulemaking.

D. June 2025 NPRM

In June 2025, the EPA issued a NPRM that included two proposals: a primary proposal and an alternative proposal. The primary proposal would have repealed all GHG regulations for fossil fuel-fired EGUs under CAA section 111 on the basis that the source category does not significantly contribute to dangerous GHG air pollution. Specifically, the EPA proposed to conclude that CAA section 111 is best read to require, or at least authorize the EPA to require, the Administrator's determination that an air pollutant emitted by a source category causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare as a predicate to

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[121] U.S. Energy Information Administration. EIA Power Monthly (December 2024). Available at: https://www.eia.gov/electricity/monthly/archive/december2024.pdf.
[122] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA-HQ-OAR-2023-0072-8913. Table 3-14.
[123] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[124] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA-HQ-OAR-2023-0072-8913. Table 3-14.

establishing emission standards for that pollutant. The EPA further proposed to determine, in a change from the 2015 NSPS and the 2024 CPS, that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution as required for the promulgation of new and existing source standards. The EPA proposed to find that the contribution of this source category is not significant because GHG emissions from those sources are a small and decreasing part of global emissions, cost-effective control measures are not reasonably available, and this Administration's priority is to protect the environment, public health, and welfare through energy dominance and independence secured through the use of fossil fuels to generate power. On the basis of the proposed finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution, the EPA proposed to repeal all GHG emissions standards for the power sector under CAA section 111, specifically the 2015 NSPS (codified in 40 CFR part 60, subpart TTTT) and the 2024 CPS (codified in 40 CFR part 60, subparts TTTTa and UUUUb).

In the alternative, based largely on a review of the BSER determinations in the 2024 CPS, the EPA proposed to repeal the emission guidelines for existing steam generating units in 40 CFR part 60, subpart UUUUb, the CCS-based requirements for coal-fired steam generating units undergoing a large modification in 40 CFR part 60, subpart TTTTa, and the CCS-based phase 2 requirements for new base load combustion turbines in 40 CFR part 60, subpart TTTTa. The EPA also solicited comment, in general, on the other standards (*e.g.*, phase 1 standards for new combustion turbines).

IV. Repeal of Sections of the Carbon Pollution Standards

The EPA is finalizing the repeal of the emission guidelines in the 2024 CPS for existing fossil fuel-fired steam generating units in 40 CFR part 60, subpart UUUUb. The EPA also is finalizing the repeal of the requirements for coal-fired steam generating units undertaking a large modification in 40 CFR part 60, subpart TTTTa and the phase 2

CCS-based requirements for new base load combustion turbine EGUs in 40 CFR part 60, subpart TTTTa. As discussed in more detail in this section of the preamble, the EPA is finalizing those repeals on the bases that (1) 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units and the degree of emission limitation in the 2024 CPS is not achievable, (2) 40 percent natural gas co-firing is not the BSER for medium-term coal-fired steam generating units and the degree of emission limitation is not achievable, (3) it would be imprudent to require States to submit plans for oil- and natural gas-fired steam generating units, and (4) 90 percent CCS is not the BSER for new base load combustion turbines and the associated standards of performance are not achievable.

The EPA acknowledges the uncertainty created by the 2024 CPS, particularly given the consequential changes to projected trends in electricity demand and generation.[125] To provide near-term relief to affected sources from the regulatory burdens of the 2024 CPS that are the cause of this uncertainty, the EPA is finalizing, based largely on the unreasonableness of the BSER determinations in the 2024 CPS, the repeal of the emission guidelines for existing steam generating units, the CCS-based requirements for coal-fired steam generating units undergoing a large modification, and the CCS-based phase 2 requirements for new base load combustion turbines.

Specifically, the EPA is finalizing the determination that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units because it has not been adequately demonstrated and because the costs are not reasonable. Furthermore, because it is unlikely the infrastructure for CCS can be deployed by the January 1, 2032

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[125] *See, e.g.*, Comments of the Power Generators Air Coalition on EPA's Proposed Repeal of Greenhouse Gas Emissions Standards for Fossil-Fuel Fired Electric Generating Units at 6, Document ID No. EPA-HQ-OAR-2025-0125-0610; Comments from the Edison Electric Institutes on the Proposed Rule Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units at 6-12, Document ID No. EPA-HQ-OAR-2025-0125-0897.

compliance date, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable. The EPA is also finalizing the determination that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units for several reasons. First, 40 percent natural gas co-firing cannot be BSER because 40 percent natural gas co-firing is a type of generation-shifting and is precluded by the Supreme Court's decision in *West Virginia*. Additionally, 40 percent natural gas co-firing cannot be BSER because consideration of the energy requirements shows that 40 percent natural gas co-firing has adverse consequences for the energy system. Moreover, because it is unlikely the infrastructure for 40 percent co-firing can practicably be deployed by the January 1, 2030 compliance date, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for medium-term coal-fired steam generating units is not achievable. Therefore, the EPA is repealing the BSER determinations, presumptive standards of performance, and all related requirements in the emission guidelines for existing long-term and medium-term coal-fired steam generating units.

Additionally, the EPA is repealing the requirements for existing natural gas- and oil-fired steam generating units because it would be an inefficient use of State resources to develop, submit, and implement state plans solely for natural gas- and oil-fired steam generating units, which comprise a relatively small part of the source category and would contribute few or no emission reductions under the existing emission guidelines. That is, it would not be reasonable for the EPA to require States to prepare plans for existing natural gas- and oil-fired steam generating units given that the Agency is repealing the requirements for existing coal-fired steam generating units.

The EPA is thus repealing the substantive requirements and, on that basis, is repealing 40 CFR part 60, subpart UUUUb—the emission guidelines for existing fossil fuel-fired steam generating units—in its entirety.

Because the EPA is determining that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units, the EPA is also repealing the CCS-based requirements for coal-fired steam generating units undertaking a large modification. The EPA is also determining that 90 percent CCS is not the BSER for new base load combustion turbine EGUs because it has not been adequately demonstrated and the costs are not reasonable. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA is determining that the phase 2 standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. Consequently, the EPA is repealing the phase 2 CCS-based requirements for new base load combustion turbine EGUs.

Although the EPA discusses each relevant repeal and the associated bases below, several observations about the 2024 CPS reinforce the fundamental issues with that prior action—and the 2015 CPP that preceded it—and support the Agency's decision to proceed with these repeals, including the repeal of standards predicated on 90 percent CCS.

First, the 2024 CPS reflected an overly restrained reading of the Supreme Court's assessment of the 2015 CPP in *West Virginia*. The EPA initially viewed that decision as barring only standards that expressly require generation shifting.[126] Upon further consideration, the EPA now accepts that decision as holding that the Agency may not impose standards with the objective or result of generation shifting at the scale the Court found to raise a major question reserved for Congress. Information reviewed since promulgation of the 2024 CPS demonstrates that standards predicated on achieving 90 percent CCS cross that threshold. Regulated sources in the relevant subcategories (*i.e.*,

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[126] *See, e.g.*, US working on power plant standards for energy transition: US EPA head, July 29, 2023, available at https://www.world-energy.org/article/34841.html ("We are working on a proposed power plant standard in the United States that helps us to transition from heavily fossil fuel resources to clean resources. . . .").

coal plants) were given the choice between complying with the standards by 2032 or ceasing operations by 2032. Because, for the reasons discussed throughout this preamble, emission limitation requirements based on 90 percent CCS are not achievable, the 2024 CPS effectively requires coal plants to shut down by 2032—a form of generation shifting. Under these circumstances, retaining these aspects of the 2024 CPS would be improper.

Second, the 2024 CPS reflected an overbroad reading of CAA section 111 that did not recognize or account for limits on the EPA's ability to identify a BSER requiring the deployment of new infrastructure over a long time horizon. In promulgating the 2024 CPS, the EPA projected—based on, as discussed below, optimistic assumptions—that complex carbon capture, transmission, and injection infrastructure that did not yet exist could be deployed nationwide within seven years, and did not view the inherent uncertainties and long time horizon as a barrier to adopting, or reason not to adopt, 90 percent CCS as the BSER. Upon further consideration, the Agency concludes that the inherent difficulties in accurately projecting such large-scale deployments counsel against selecting BSERs predicated on large-scale national infrastructure buildouts years into the future, particularly given the statute's eight-year cycle for reviewing the effectiveness of promulgated standards.

Third, and relatedly, the 2024 CPS reflected an overbroad reading of CAA section 111 that did not recognize or account for the scale of the infrastructure required for compliance, including the difference between systems that sources can apply to meet the standards that apply to them and systems that require significant investment and performance by third parties. Owners and operators of power plants subject to 90 percent CCS-based requirements are dependent on third parties to develop and operate virtually all the components of CCS. Transport and storage, in particular, differ from the types of equipment the Agency has historically selected as BSER. All relevant third parties would need to timely complete their components of the infrastructure across large geographic areas for the owners and operators to be able to implement the CCS requirements by the compliance date, and thereafter, owners and operators must rely on the continued cooperation and operation of these third parties. Upon further consideration, the EPA concludes that the scale of the necessary infrastructure, including the necessary involvement of third parties nationwide, is different in kind from control measures historically considered under CAA section 111 and counsels against selecting 90 percent CCS as BSER.

The remainder of this section details the rationale for the repeal of the emission guidelines for existing fossil fuel-fired steam generating units, the CCS-based requirements for coal-fired steam generating units undertaking a large modification, and the 2024 CCS-based requirements for new combustion turbine EGUs. The EPA carefully considered the comments received on the June 2025 NPRM in the development of this final rulemaking and the supporting rationale. The EPA discusses some of the overarching comments received on the June 2025 NPRM and provides responses in this section of the preamble.[127]

Comments: The EPA received extensive comments on both the primary and alternative proposals of the June 2025 NPRM. Among the group of commenters generally in favor of the proposals, some supported finalizing the primary proposal, some supported finalizing the alternative proposal, and others supported finalizing both proposals. Among the commenters in favor of finalizing both proposals, some recommended finalizing the alternative proposal first, followed by the primary proposal, while others urged the EPA to finalize both proposals simultaneously. Other commenters opposed both proposals.

[127] Responses to substantial comments on specific issues are addressed in the relevant sections of this preamble. Responses to additional comments are in the RTC, available in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).

EPA Response: Based on consideration of those comments and other factors, in this final rule, the EPA is finalizing only the alternative proposal in the June 2025 NPRM—that is, the proposal to repeal the emission guidelines for existing steam generating units and the CCS-based requirements for new base load combustion turbine EGUs and coal-fired steam generating units undertaking a large modification. This final action is based on a record-focused reevaluation of the BSER determinations for the relevant subcategories. As previously explained, the EPA is taking this final action to provide near-term relief from regulatory requirements it now finds are unlawful or otherwise unreasonable. The EPA is not, in this rulemaking, finalizing the primary proposal in the June 2025 NPRM to repeal all GHG regulations for fossil fuel-fired EGUs under CAA section 111 on the basis that the source category does not significantly contribute to qualifying air pollution. The EPA is instead issuing a supplemental proposal soliciting additional public comment on the underlying question raised in the primary basis of the June 2025 NPRM: Whether the EPA lacks statutory authority to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111 under the applicable statutory standard for such regulation. The primary proposal in the June 2025 NPRM sought public comment on whether fossil fuel-fired EGUs "contribute significantly" to air pollution, and the supplemental notice seeks public comment on the distinct question whether global climate change concerns satisfy the threshold requirement in CAA section 111(b)(1)(A) that the source category emissions contribute significantly to "air pollution which may reasonably be anticipated to endanger public health or welfare." We will evaluate both proposed approaches and rationales in taking final action, as both issues—contribution and endangerment—were the subject of significant interpretive and policy changes in the 2009 Endangerment Finding and the 2015 NSPS (as retained by the 2024 CPS) that extended the Agency's novel approach to power plant stationary sources. The EPA therefore is responding in this final rule only to comments on the alternative proposal that the Agency is finalizing—the proposal to repeal 40 CFR part 60, subpart UUUUb and certain components of 40 CFR part 60, subpart TTTTa. The EPA is not responding at this time to comments that relate solely to the June 2025 primary proposal.

Comments: Some commenters opposed to the proposal to repeal the emission guidelines and other CCS-related requirements asserted that such repeal would be unlawful because the EPA must consider alternatives to the BSER determinations and requirements at issue and/or immediately promulgate different requirements based on alternative BSERs. Commenters asserted that the CAA requires the EPA to set standards of performance under CAA section 111(b) for GHG emissions from fossil fuel-fired power plants because they are listed as a source category under CAA section 111 and that the Agency has previously determined that such emissions contribute significantly to GHG air pollution that endangers public health and welfare. Additionally, these commenters asserted that CAA section 111(d) requires the EPA to promulgate emission guidelines for existing sources that would be subject to the standards under CAA section 111(b) if the sources were new sources. Commenters asserted that the repeal of the 2024 CPS's emission guidelines and standards of performance at issue in this rulemaking would leave these legal mandates unfilled and that repealing these requirements without considering and/or promulgating alternative requirements based on alternative BSERs would be arbitrary and capricious.

EPA Response: The EPA disagrees with these comments. The EPA carefully considered alternatives to repeal of the emission guidelines and standards of performance (*e.g.*, whether to revise the BSER determinations or compliance schedules for the affected sources and whether to promulgate different standards immediately) and is determining that it is not necessary to do so at this time. The EPA remains concerned that it lacks the requisite statutory authority to regulate GHG emissions from power plants in the first instance under the applicable statutory standard for regulation. Indeed, other commenters urged that the EPA must resolve this predicate question before promulgating additional or different standards. Accordingly, the EPA is exercising its discretion to proceed through multiple steps that will address the totality of the problem before it in an orderly fashion.

In a concurrently issued supplemental proposal, the EPA is proposing to find that the Agency lacks the requisite legal basis to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. These proposed bases are in addition to those presented in the primary proposal in the June 2025 NPRM and will be considered together with the bases previously presented in taking final action. If finalized as proposed, this subsequent action would abrogate any legal requirement and authority to replace the BSER determinations and associated requirements that the EPA is repealing in this final rule. Such action would render it inappropriate and unnecessary to promulgate any alternative BSER determinations, standards of performance, or compliance schedules. Conversely, if the EPA determines that it has the requisite statutory authority, the Agency would conduct additional analyses and propose any necessary and appropriate additional requirements for the fossil fuel-fired EGU source category at that time, having confirmed its statutory basis for doing so.

As a general matter, "[n]othing prohibits federal agencies from moving in an incremental manner."[128] The EPA notes that CAA section 111 contemplates that the Agency need not immediately promulgate standards upon listing a source category and that review of regulations for a previously listed source category occurs on an eight-year cycle. Moreover, CAA section 111(b)(1)(B) does not require the Agency to regulate all types of emissions simultaneously, and CAA section 111(d) does not provide a deadline

[128] *Fox Television Stations*, 556 U.S. at 522; *see, e.g.*, Pub. Safety Spectrum All. v. FCC, No. 24-1363, slip op. 20 (D.C. Cir. July 21, 2026) (it was reasonable for the FCC to defer making relevant decisions to a subsequent action).

for promulgating emission guidelines. Even with respect to source categories for which no regulations exist, Congress previously provided a prioritization scheme in CAA section 111(f) under which the EPA was required to promulgate such regulations over the course of a six-year period. The EPA has consistently taken the position that it need not, in any particular CAA section 111 rulemaking, address all potential issues relevant to the at-issue source category. This final action does not repeal all requirements applicable to the fossil-fuel fired EGU source category, and as noted elsewhere in this preamble, nothing in this final action disturbs criteria pollutant emission standards applicable to power plants regulated under pre-2015 listings.

Thus, the EPA need not analyze and promulgate alternative BSERs and associated requirements to address serious issues identified with certain existing standards. In this context, this final rule simply represents a permissible first step in a multi-step process.[129] As noted above, the EPA is taking this first step to provide near-term relief from 2024 CPS requirements that it is now determining to be unlawful or otherwise unreasonable and which, absent further action, would imminently begin forcing the expenditure of significant resources. Promulgation of alternative BSERs or compliance schedules at this time would require completing multiple additional steps, including resolving questions regarding the Agency's statutory authority and analyzing competing alternative BSERs and requirements, all of which would delay resolution of the distinct issues addressed in this rulemaking and defeat the purpose of resolving these distinct issues before regulated sources are put to the choice between expending significant resources to comply, or

[129] *See* Grand Canyon Air Tour Coal. v. FAA, 154 F.3d 455, 471 (D.C. Cir. 1998) ("ordinarily, agencies have wide latitude to attack a regulatory problem in phases and . . . a phased attack often has substantial benefits"); Las Vegas v. Lujan, 891 F.2d 927, 935 (D.C. Cir. 1989) (upholding agency action that was a first step toward a "complete solution," stating that "agencies have great discretion to treat a problem partially"); Nat'l Ass'n of Broadcasters v. FCC, 740 F.2d 1190, 1210 (D.C. Cir. 1984) (it is reasonable for an agency to "defer resolution of issues raised in a rulemaking even when those issues are 'related' to the main ones being considered"; the inquiry into when agencies may defer resolution of issues raised in a rulemaking to a subsequent action is "a pragmatic one").

planning to close, before the current 2032 compliance deadline (or other upcoming compliance deadlines, as applicable).

The EPA does not believe its repeal of certain 2024 CPS standards and requirements runs afoul of case law such as *Regents of the University of California* and *State Farm.* These cases stand for the proposition that when an agency "rescinds a prior policy its reasoned analysis must consider the 'alternative[s]' that are 'within the ambit of the existing [policy].'"[130] In concluding that the CAA and general principles of administrative law do not require the EPA to analyze and promulgate alternative, replacement BSER determinations or requirements immediately and as part of this discrete repeal, the Agency again emphasizes that this action is the first step in what is intended to be a multi-step rulemaking process. If the second step of this process is finalized as proposed, the "existing policy" will be mooted based on the lack of legal basis for that policy in the first instance. The EPA is thus not promulgating new standards for existing coal-fired steam generating units or for new base load combustion turbines in this final rule, and, accordingly, need not develop alternative BSER determinations to support such new and additional standards.

In analyzing this aspect of the problem, the EPA reviewed the alternatives it considered prior to selecting the BSER and standards finalized in the 2024 CPS to examine the scope and nature of possible regulatory alternatives. The Agency believes that its prior consideration and rejection of other potential BSERs in the 2024 CPS rulemaking demonstrates that further analyzing additional alternative BSERs and requirements would be unnecessary under the circumstances here. In the 2024 CPS, the EPA considered and rejected a range of potential alternatives to the BSERs ultimately selected. For long-term coal-fired steam generating units now subject to standards based on 90 percent CCS, the EPA considered partial CCS at lower capture rates, natural gas

[130] *Regents*, 591 U.S. at 30 (quoting *State Farm*, 463 U.S. at 51).

co-firing, and heat rate improvements.[131] The EPA rejected partial CCS "because it achieves substantially fewer unit-level reductions at greater cost, and because CCS at 90 percent is achievable."[132] The Agency also noted that "the IRC section 45Q tax credit may not be available to defray the costs of partial CCS and the emission reductions would be limited."[133] As explained in section IV.A.1 of this preamble, the EPA now rejects the conclusion that 90 percent CCS is adequately demonstrated and achievable and further finds that the IRC section 45Q tax credit should not be accounted for when evaluating the reasonableness of the costs of the BSER. The EPA therefore believes the costs of partial CCS would be significantly higher than anticipated in the 2024 CPS and therefore remains an inappropriate alternative. With regard to natural gas co-firing as an alternative to 90 percent CCS, as discussed in section IV.A.2 of this preamble, the EPA is determining in this final rule that this control strategy amounts to impermissible generation shifting, thereby disqualifying it from being the BSER. And the EPA explained in the 2024 CPS that it was not finalizing heat rate improvements as the BSER "because of the limited reductions and potential rebound effect."[134] Similarly, for medium-term coal-fired EGUs, the 2024 CPS considered CCS and heat rate improvements as potential BSERs and rejected each.[135] Thus, based on the EPA's earlier assessments and the further analysis conducted for purposes of this final rule, potential alternatives to 90 percent CCS for long-term coal-fired units and 40 percent natural gas co-firing for medium-term coal-fired units are not obvious and suffer from their own shortcomings. As noted above, fully analyzing and working through these issues is a distinct task that warrants a distinct process that would be most appropriate to undertake

[131] 89 FR 39798, 39846 (May 9, 2024).
[132] *Id.*
[133] *Id.*
[134] *Id.*
[135] *Id.* at 39895-96.

after, and pending the results of, the Agency's consideration of the scope of its statutory authority.

For new base load combustion turbines, the 2024 CPS included consideration of potential alternative BSERs including lower-emitting fuels, high efficiency generation, and hydrogen co-firing.[136] In the 2024 CPS, the EPA explained that lower-emitting fuels are not the BSER for new base load combustion turbines because they would achieve few emission reductions.[137] And the EPA further explained that, "[i]n light of public comments and additional analysis, uncertainties regarding projected costs prevent the EPA from determining that low-GHG hydrogen is a component of the BSER at this time."[138] This previous evaluation of potential alternative BSERs in the 2024 CPS corroborates the EPA's conclusion in this rulemaking that it is not necessary for the Agency to consider alternatives to repeal of the 90 percent CCS, phase 2 BSER for new base load combustion turbines.

Comments: Some commenters asserted that the EPA's proposed repeal of the 2024 CPS failed to consider the disbenefits of that proposal, namely, forgone emissions reductions. One commenter noted that the standards the Agency was proposing to repeal would reduce CO_2 emissions by 1.38 billion metric tons over roughly two decades. The commenter further stated that the standards the EPA was proposing to repeal would also secure reductions of tens of thousands of tons of particulate matter, sulfur dioxide, and nitrogen oxide emissions. Commenters argued that the Agency had failed to consider the public health benefits of the 2024 CPS and the corresponding disbenefits of repealing certain requirements of that rule, and that this purported oversight rendered the proposed repeal inconsistent with the Administrative Procedure Act and the CAA.

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[136] *Id.* at 39924.
[137] *Id.*
[138] *Id.* at 39939.

EPA Response: The EPA disagrees with these comments. The Agency acknowledges that CO_2 emission reductions are a relevant consideration in making BSER determinations under a regulatory framework that addresses GHG emissions from the affected sources. The EPA also recognizes that this action to repeal requirements of the 2024 CPS forgoes the CO_2 emission reductions that were projected to be achieved under the 2024 CPS. However, the EPA emphasizes that the repeal of the 2024 CPS requirements is based on the Agency's technical determinations that 90 percent CCS and 40 percent natural gas co-firing do not satisfy certain threshold legal criteria to be eligible to be the BSER. For 90 percent natural gas co-firing, the EPA is determining, among other things, that CO_2 capture at this rate is not adequately demonstrated; the Agency is also determining that 40 percent natural gas co-firing is impermissible generation shifting. Because each of these determinations disqualifies the emissions control strategy from further consideration, the amount of CO_2 emission reductions available through implementation of these strategies cannot compel a different outcome. Further, as discussed in the relevant subsections of this preamble, many of the selected control strategies underlying the at-issue 2024 CPS requirements are infeasible, and the EPA has significantly revised its projections and analysis in the 2024 CPS with respect to the timeline for implementation. These issues mean that the emissions reductions projected in the 2024 CPS were not likely to come to fruition in any event absent outcomes inconsistent with the CAA (*i.e.*, forced plant closures because compliance by the applicable deadline is not possible).

Separately, the EPA is also determining that the cost of 90 percent CCS is unreasonable and that the energy impacts associated with 40 percent co-firing are unreasonable. The amount of CO_2 emission reductions is relevant to the balancing of the BSER factors, which also include cost and nonair quality health and environmental impacts and energy requirements. As explained in this section of the preamble, the EPA has considered the available emission reductions associated with 90 percent CCS and 40 percent natural gas co-firing and is finding that, on balance, these emission control strategies are unreasonable. Furthermore, as explained in section IV.3 of this preamble, the EPA is repealing the requirements for oil and natural gas-fired steam generating units in part because the BSERs for these units in the 2024 CPS would not have achieved appreciable CO_2 emission reductions. The EPA has thus considered the foregone CO_2 emission reductions and determined that its action is reasonable notwithstanding.

While the EPA acknowledges that the 2024 CPS would have also resulted in reductions of co-pollutants including particulate matter, sulfur dioxide, and nitrogen oxides, reductions of these pollutants in the 2024 CPS, or foregone emission reductions of these pollutants in this action, did not factor into the Agency's BSER determinations for the regulated pollutant—CO_2—emitted from the regulated sources. And even if the EPA were to consider these incidental reductions of co-pollutants, the Agency would determine that the costs and energy impacts of the controls should be weighted more heavily than those forgone reductions.

The EPA's consideration of foregone emission reductions together with costs in relation to projections in the 2024 CPS is consistent with the Supreme Court's statement in *Michigan v. EPA*, 576 U.S. 743 (2015), that "reasonable regulation ordinarily requires paying attention to the advantages *and* the disadvantages of agency decisions."[139] That is, the EPA has considered the reductions that the 2024 CPS would have achieved in CO_2 emissions, as well as the reductions in the other pollutants emitted by power plants, including particulate matter, sulfur dioxide, and nitrogen oxides. The EPA has also considered the health impacts of reducing emissions of these pollutants. Those emissions reductions and health impacts are noted in section V.A of this preamble. However, the EPA believes that any benefits from them are outweighed by the costs of the 2024 CPS,

[139] *Michigan*, 576 U.S. at 753 (emphasis in original).

including the costs to the industry (and, in many instances, to the ratepayers who will absorb those costs through higher electricity bills) of complying with the requirements, as also noted in section V.A of this preamble, as well as the adverse energy impacts of using natural gas for co-firing, as noted in section IV.A.2.a of this preamble. In the EPA's view, this relative weighting is confirmed by the uncertainty of actually achieving the benefits attributed to the 2024 CPS, in light of the record and legal deficiencies in the 2024 CPS's determination of CCS and co-firing as BSER, as noted in sections IV.A.1 and IV.A.2 of this preamble. Accordingly, the EPA believes that today's action to repeal the 2024 CPS is reasonable and consistent with the *Michigan* statement cited above concerning reasonable regulation.

A. Repeal of the Emission Guidelines for Existing Fossil Fuel-Fired Steam Generating Units

This section details the rationale for the repeal of the emission guidelines for existing fossil fuel-fired steam generating units.

1. CCS-Based Requirements for Long-Term Existing Coal-Fired Steam Generating Units

In the 2024 CPS, the EPA determined the BSER for long-term coal-fired steam generating units to be 90 percent CCS. The EPA premised that BSER specifically on 90 percent CO_2 capture using an amine solvent-based system, CO_2 transport through a pipeline, and geologic sequestration of the CO_2 in a saline reservoir. In the 2024 CPS, the EPA argued that 90 percent CCS, including the 90 percent CO_2 capture component, was adequately demonstrated. The EPA further argued that 90 percent CCS satisfied the other criteria for BSER, including that costs were reasonable based on counting the IRC section 45Q as a reduction in the cost to the affected source of 90 percent CCS. Based on application of the 90 percent CCS BSER to the affected sources, the EPA established a degree of emission limitation and argued this was achievable by the compliance date of

January 1, 2032, considering the time necessary to deploy capture equipment, transport, and sequestration.

The EPA proposed to repeal the requirements for long-term coal-fired steam generating units based largely on a reassessment of the record for the 2024 CPS. Specifically, the EPA proposed that 90 percent CO_2 capture, and therefore 90 percent CCS as a whole, have not been adequately demonstrated. The EPA further proposed that the average unit-level costs of 90 percent CCS were unreasonable. In the June 2025 NPRM, the EPA evaluated the average unit level costs assuming a lower capacity factor of the host EGU and operation beyond the 12-year period of availability of the IRC section 45Q tax credit. The reduced amount of CO_2 that would be captured and eligible for the IRC section 45Q tax credit resulted in higher costs than in the 2024 CPS. The EPA further proposed that the IRC section 45Q should not be counted as a reduction in the costs of 90 percent CCS. Finally, the EPA proposed that the degree of emission limitation in the 2024 CPS is not achievable because it is unlikely that the infrastructure (including the capture system, pipelines, and sequestration) for CCS can be deployed by the January 1, 2032 compliance date.

The EPA has reassessed the record underlying the 2024 CPS. The EPA is finalizing the determination that CCS with 90 percent capture is not the BSER for long-term existing coal-fired steam generating units because 90 percent CO_2 capture and, therefore, 90 percent CCS have not been adequately demonstrated and the costs are unreasonable. Additionally, the capture, pipeline, and sequestration infrastructure necessary for 90 percent CCS for the fleet of existing coal-fired steam generating units does not currently exist and would need to be broadly deployed. It is unlikely the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, and the EPA is therefore finalizing the determination that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable. Consequently, for the reasons explained in the June 2025 NPRM[140] and discussed below, the EPA is finalizing the repeal of the requirements in the emission guidelines pertaining to long-term existing coal-fired steam generating units.

a. Adequately Demonstrated

CCS with 90 percent capture involves the capture of 90 percent of the CO_2 emissions from the EGU, compression and transport of the captured CO_2 via pipeline, and sequestration in geologic storage. Due to the relatively low concentration of CO_2 in the flue gas, an amine solvent-based capture system is better suited for application to the post-combustion flue gas of fossil fuel-fired EGUs than other CO_2 removal technologies (*e.g.*, pressure-swing adsorption). CO_2 removal occurs by reactive absorption of the CO_2 from the flue gas into the amine solution in an absorption column. The amine reacts with CO_2 but will also react with impurities in the flue gas, including sulfur dioxide (SO_2). Particulate matter (PM) will also affect the capture system. Adequate removal of SO_2 and PM prior to the CO_2 capture system is therefore necessary. After pretreatment of the flue gas with conventional SO_2 and PM controls, the flue gas goes through a quencher to cool the flue gas and remove further impurities before the CO_2 absorption column. After absorption, the CO_2-rich amine solution passes to the solvent regeneration column, while the treated gas passes through a water and/or acid wash column to limit emission of amines or other byproducts. In the solvent regeneration column, the solution is heated (using steam) to release the absorbed CO_2. The released CO_2 is then compressed and transported to a sequestration site. In an integrated CO_2 capture system, steam and electricity for the capture process are provided by the host-EGU; this avoids the need to capture additional emissions from any auxiliary boilers or cogeneration units.

In the 2024 CPS, the CO_2 capture component of the 90 percent CCS BSER was premised on an integrated amine solvent-based CO_2 capture system with 90 percent

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[140] 90 FR 25752, 25769-73 (June 17, 2025).

removal of CO_2 from the post-combustion flue gas of the host EGU. The EPA previously argued that such a system was adequately demonstrated.

The EPA has reevaluated the record and is determining in this final rulemaking that, critically, 90 percent capture of the CO_2 from flue gas of an EGU has not been adequately demonstrated. As a result, 90 percent CCS has not been adequately demonstrated and cannot be the BSER for long-term coal-fired steam generating units. The EPA is basing this conclusion primarily on a revised evaluation of the record in the 2024 CPS, as detailed in this section of the preamble.[141] The EPA is additionally considering several developments since the EPA promulgated the 2024 CPS (*e.g.*, changes in the plans of certain CCS projects).

In the 2024 CPS, the emission guidelines required States to establish plans that would require long-term existing coal-fired steam generating units to achieve an annual standard of performance based on capturing 90 percent of the unit's total CO_2 emissions. However, the record for 90 percent capture as adequately demonstrated did not include an example of a commercial scale coal-fired steam generating unit that was already capturing 90 percent of its annual CO_2 emissions. Instead, the EPA attempted to argue that 90 percent capture has been adequately demonstrated based on other evidence for the technology at that time. Specifically, the EPA relied primarily on evidence that consisted of the operation of the CO_2 capture system at Boundary Dam Unit 3, fixes applied at Boundary Dam Unit 3, and testing on new solvents from different vendors.[142] Consequently, the EPA extrapolated from that combination of primary evidence to determine that 90 percent capture would perform as anticipated for the affected sources.

[141] *See* Nat'l Ass'n of Home Builders v. EPA, 682 F.3d 1032, 1038 (D.C. Cir. 2012) ("EPA did not rely on new facts, but rather on a reevaluation of which policy would be better in light of the facts . . . . *Fox* makes clear that this kind of reevaluation is well within an agency's discretion." (citing 556 U.S. at 514-15)).

[142] The EPA also included other, secondary observations (*e.g.*, projects in development) that would be insufficient on their own to conclude 90 percent capture is adequately demonstrated.

On that basis, the EPA concluded that 90 percent capture was adequately demonstrated for existing coal-fired steam generating units.

The only datapoint for commercial scale post-combustion CCS on a fossil fuel-fired EGU, with integrated steam and power, is Boundary Dam Unit 3. However, between 2014 and 2022, the capture system at Boundary Dam achieved a total capture efficiency of not more than 63 percent over the course of a calendar year.[143,144] This total annual capture efficiency is substantially below the 90 percent capture level specified by the BSER. While the EPA had acknowledged the challenges and underperformance of the capture system at Boundary Dam in the 2024 CPS, the Agency asserted that fixes were available or could be made to address those issues. However, many of those fixes were already made, and performance remained below the design capture efficiency.[145] The EPA also previously argued that new solvents were available that could capture CO_2 at higher rates to address these gaps.[146] However, in the 2024 CPS, the EPA failed to reasonably account for potential underperformance of capture systems using new solvents, and the experience at Boundary Dam shows it would be reasonable to anticipate that such capture systems would similarly underperform.[147] Furthermore, the EPA also failed to account for any decrease in operating-availability of capture, even though the

[143] Here, total capture efficiency is equivalent to the mass of CO_2 captured relative to (*i.e.*, divided by) the mass of CO_2 that the EGU would otherwise emit (including the mass of CO_2 produced in the combustion chamber of the EGU plus the mass of CO_2 produced by any auxiliary equipment that supports the capture process) over a given period (*e.g.*, annual).
[144] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies* (2022). Available at: https://dx.doi.org/10.2139/ssrn.4286430.
[145] The most recently reported total capture efficiency when operating was 83 percent on an instantaneous basis. Accounting for periods when the capture system is offline, the total annual capture efficiency would be lower.
[146] 95 percent total capture on an instantaneous basis, not accounting for uncertainty in real-world operation or availability.
[147] As the only commercial scale and long-term application of CO_2 capture on a fossil fuel-fired EGU, Boundary Dam's underperformance is a reasonable quantification of potential underperformance.

annual operating-availability of the capture system at Boundary Dam has been less than 100 percent.[148] In combination, a capture system would achieve much less than 90 percent total capture efficiency. On review, the EPA's prior extrapolation fails to support CCS with 90 percent capture as adequately demonstrated. The EPA's other tangential arguments in the 2024 CPS similarly fail to show that 90 percent capture has been adequately demonstrated (including projects in development, as discussed in section IV.A.1.a.iv of this final rule preamble). Considering these factors, the EPA is finalizing the determination that CCS with 90 percent capture and, consequently, 90 percent CCS are not adequately demonstrated for existing coal-fired steam generating units. The following subsections provide further explanation.

i. Extrapolation from Boundary Dam Unit 3

In the 2024 CPS, the EPA based the determination that 90 percent CO_2 capture was adequately demonstrated on the record for amine-solvent CO_2 capture.[149] Thus, the EPA relied heavily on the operation of carbon capture at the commercial scale 110 megawatt (MW) coal-fired Boundary Dam Unit 3 (Saskatchewan, Canada) to demonstrate 90 percent capture. Boundary Dam has operated CCS since 2014. The unit uses Shell's amine-based CANSOLV® solvent technology to capture CO_2 from the post-combustion flue gas of the coal-fired boiler.[150] Captured CO_2 is then compressed, transported by pipeline, and used for enhanced oil recovery (EOR) or stored in a saline aquifer at the Aquistore site.[151] While Boundary Dam Unit 3 achieved 89.7 percent capture over a 3-day test early in its operation, longer-term capture levels have been

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[148] Between 2015-2022, the availability of the capture system relative to the EGU was, at best, 94 percent.
[149] 89 FR 39798, 39848 (May 9, 2024).
[150] Giannaris, S., *et al.* SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. *Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies* (2021). Available at: http://dx.doi.org/10.2139/ssrn.3820191.
[151] Aquistore. Available at: https://ptrc.ca/aquistore.

lower.[152] Between 2015 and 2022, Boundary Dam achieved a total capture efficiency of not more than 63 percent in a calendar year.[153] This total long term capture efficiency is substantially below the 90 percent capture efficiency of the BSER.

This lower total capture efficiency is due to, among other things, the capture system at Boundary Dam Unit 3 typically processing less than all of the flue gas, in part to "maintain long-term reliable operation."[154] Prior to 2023, the CO_2 capture system at Boundary Dam Unit 3, when operating, processed up to approximately 75 percent of the flue gas with 90 percent CO_2 capture from the processed flue gas.[155] The EPA argued in the 2024 CPS that such capture from the majority of the flue gas supported the determination of 90 percent capture from all of the flue gas as adequately demonstrated; however, this ignores that the total capture efficiency was substantially less than the 90 percent design capture efficiency.

Additionally, Boundary Dam Unit 3 has experienced various technical challenges that have reduced its performance.[156] These include fouling of the CO_2 absorber due to PM (fly ash), buildup of scale on heat exchangers, biological fouling in the wash-water section of the CO_2 absorber, foaming of the amine solvent in the CO_2 absorber, and damage to the CO_2 compressor. Fouling in the CO_2 absorber affects the throughput of the

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[152] SaskPower Annual Report (2015–16). Available at: https://www.saskpower.com/-/media/saskpower/about-us/reports/past-reports/report-annualreport-2015-16.pdf.

[153] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: https://dx.doi.org/10.2139/ssrn.4286430.

[154] SaskPower. "Docket ID No. EPA–HQ–OAR–2023–0072: SaskPower Correction of Reference to Boundary Dam Unit 3 Emissions Performance in Proposed Rule" (August 4, 2023). Document ID No. EPA-HQ-OAR-2023-0072-0687.

[155] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: https://dx.doi.org/10.2139/ssrn.4286430.

[156] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: https://dx.doi.org/10.2139/ssrn.4286430.

process by increasing the pressure drop (*i.e.*, difference in pressure between the bottom and top of the absorber) such that it cannot be overcome by the draft fans (*i.e.*, more energy is required to move the same volume of flue gas than the fans are designed to provide). Boundary Dam Unit 3 has implemented improvements to its particulate controls (electrostatic precipitator) and added more spray-wash systems to mitigate fouling due to fly ash. Caustic shocking of the wash-water section can reduce the buildup of biological material. Buildup of scale on heat exchangers reduces throughput by increasing pressure drop, while the layer of scale reduces the rate of heat transfer. To address this issue, redundant heat exchangers with isolations were installed in 2017 to allow for removal of scale without shutting down the CO_2 capture system. Finally, damage to the CO_2 compressor caused by a loose bolt, and issues with a leaking intercooler in the compressor, forced the CO_2 capture system to be offline for several months in 2021 and the start of 2022. While the compressor was repaired, the unit lacks a redundant compressor in the event of a similar outage. Importantly, despite these attempts to improve operation, the unit continues to underperform. Furthermore, outages to address these issues have contributed to a lower total capture efficiency.

Comments: Some commenters agreed that Boundary Dam Unit 3 does not support 90 percent capture as adequately demonstrated. Commenters noted the low total capture efficiency achieved by the unit over time and the challenges faced by the unit. Other commenters argued Boundary Dam Unit 3 does support 90 percent capture as adequately demonstrated because of the capture rate from the processed flue gas and the fixes to the unit.

EPA Response: In approximately 2024, SaskPower made additional improvements at Boundary Dam Unit 3 to increase throughputs, and SaskPower noted that the capture system was processing a greater portion of the flue gas (up to 95 percent of the flue gas, with 87 percent capture from the processed flue gas, resulting in 83 percent total capture when operating).[157] SaskPower has not reported whether Boundary Dam Unit 3 has maintained that performance in the long term.[158] Notably, at those higher throughputs, the capture efficiency from the processed flue gas is lower. Moreover, even with those improvements, Boundary Dam continues to operate with capture efficiencies below design specification. Therefore, the fixes applied at Boundary Dam Unit 3 do not support 90 percent capture as adequately demonstrated.

Additionally, the operating-availability of the capture system at Boundary Dam Unit 3 has been less than 100 percent.[159] Between 2015 and 2022, annual operating-availability of the capture plant relative to the EGU varied between 58 and 94 percent.[160] In 2023, the average quarterly operating-availability of the capture plant was approximately 85 percent.[161] Operating-availability remained at this level in 2024.[162] Lower operating-availabilities further contribute to lower total capture efficiencies.

The total capture efficiency at Boundary Dam Unit 3 has been less than 90 percent because the capture system has not processed all the flue gas. Also, the capture efficiency is still less than 90 percent when the capture system is operating even after applying fixes. Additionally, the operating-availability of the capture system is less than

[157] U.S. EPA, "Meeting with SaskPower to Discuss CCS at Boundary Dam Unit 3" (January 18, 2024). Document ID No. EPA-HQ-OAR-2023-0072-8906.

[158] Status updates from Boundary Dam from the second quarter of 2022 onward report average daily capture rates on a metric tons per day basis, capture system availability, and emissions intensity. Capture efficiency is not reported. *See* SaskPower. BD3 Status Update: Q4 2024. Available at: https://saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q4-2024.

[159] Here, operating-availability is the percent of time that the capture system is operating relative to the time that the EGU is operating.

[160] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: https://dx.doi.org/10.2139/ssrn.4286430.

[161] SaskPower. BD3 Status Update: Q4 2023. Available at: https://www.saskpower.com/about-us/our-company/blog/2024/bd3-status-update-q4-2023.

[162] SaskPower. BD3 Status Update: Q4 2024. Available at: https://saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q4-2024.

100 percent. Considering this, the EPA concludes that the experience at Boundary Dam Unit 3 does not support 90 percent CCS as adequately demonstrated. Furthermore, the capacity of Boundary Dam Unit 3 is less than the capacity of the average U.S. coal-fired steam generating unit of approximately 430 MW. Because CCS at Boundary Dam Unit 3 underperformed at 110 MW, the EPA concludes that 90 percent capture would similarly underperform at any units greater than 25 MW, including larger units.

In the 2024 CPS, the EPA argued that new solvents achieving 95 percent capture efficiency were evidence that 90 percent capture was adequately demonstrated. However, the EPA failed to reasonably account for the performance that could be achieved in practice. The only datapoint for commercial scale post-combustion CCS on a fossil fuel-fired EGU, with integrated steam and power, is Boundary Dam Unit 3. As noted in the June 2025 NPRM, it would be reasonable to anticipate that a capture system using a new solvent would underperform to a similar degree as Boundary Dam.[163] A capture system using a new solvent, even in a process designed to achieve 95 percent capture on an instantaneous basis, would achieve just 66 percent total capture efficiency and still fail to achieve 90 percent capture if the capture system using a new solvent performed proportionately to Boundary Dam's best annual performance.[164] Even under more optimistic circumstances, assuming Boundary Dam's best annual operating-availability and that a new solvent capture system performs proportionally to Boundary Dam's recent performance, the resulting total annual capture efficiency would be only 82 percent.[165] In

[163] 90 FR 25752, 25769 (June 17, 2025).

[164] 95 percent design capture x (63 percent total annual capture/ 90 percent design capture) = 66 percent total annual capture efficiency. Between 2015 and 2022, Boundary Dam Unit 3 achieved a total annual capture efficiency of not more than 63 percent. *See* Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: https://dx.doi.org/10.2139/ssrn.4286430.

[165] 94 percent availability x 95 percent design capture x (83 percent total capture/ 90 percent design capture) = 82 percent total annual capture efficiency.

combination, a capture system would achieve much less than 90 percent total capture efficiency. On review, the EPA's prior extrapolation fails to support CCS with 90 percent capture as adequately demonstrated. Considering these factors, the EPA is finalizing the determination that CCS with 90 percent capture is not adequately demonstrated for existing coal-fired steam generating units.

ii. CO_2 Capture at Other Coal-fired Steam Generating Units

In the 2024 CPS, to support the determination of 90 percent capture as adequately demonstrated, the EPA cited other applications of CCS at coal-fired steam generating units. These included CO_2 capture at the Argus Cogeneration Plant (Trona, California), at AES's Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) plants, and at Plant Barry's (Mobile, Alabama) 25 MWe (megawatt-equivalent) project.[166] These projects were not of an equivalent size to commercial scale or, in the case of the Argus Cogeneration Plant, captured far less than 90 percent of CO_2. These earlier examples would have informed the design of the capture system at Boundary Dam Unit 3. However, the lessons learned from such projects failed to limit the underperformance of the CO_2 capture system at Boundary Dam. Consequently, they do not mitigate the anticipated underperformance in the extrapolation of 90 percent CCS and cannot support 90 percent capture as adequately demonstrated.

In the 2024 CPS, the EPA also cited the Petra Nova project at W.A. Parish Unit 8 (Thompsons, Texas). The Petra Nova project began operation in 2017, and the owner put the facility into reserve shutdown (*i.e.,* idled) in May 2020, citing the poor economics of utilizing captured CO_2 for EOR at that time. On September 13, 2023, the carbon capture

[166] Dooley, J.J., *et al.* "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. (2009). Available at: https://doi.org/10.2172/967229.

facility at Petra Nova restarted.[167] A final report from the National Energy Technology Laboratory (NETL) details the challenges that the project faced over an initial 3-year period, including leaks from heat exchangers, build-up of slurry and solids on the flue gas blower, and build-up of scale on various components.[168] Petra Nova captured on average 92.4 percent of the CO_2 from the 240 MWe flue gas processed over a 3-year period while operating. However, that does not account for emissions during outages of the CO_2 capture system. Maintenance to address outages directly attributable to the CO_2 capture facility was approximately 10 percent of the year on average over that timeframe. Accounting for those outages alone would, approximately, result in a total capture efficiency of 83.2 percent. Furthermore, Petra Nova processes a 240 MWe portion of the flue gas from the 610 MW W.A. Parish Unit 8. At full load, that would equate to a capture efficiency of approximately 36 percent of the emissions from the coal-fired steam generating unit.[169] With 10 percent outages, this would be reduced further to 32.4 percent. Additionally, the 90 percent CCS BSER in the 2024 CPS was premised on the CO_2 capture plant using integrated steam and electricity from the host EGU. However, Petra Nova uses an auxiliary natural gas-fired combustion turbine cogeneration unit to provide steam and electricity to the CO_2 capture process, and the system does not capture the CO_2 emissions from the auxiliary cogeneration unit. This design is inconsistent with the premise of the CCS BSER in the 2024 CPS. A system consistent with the premise of the BSER uses integrated steam and power and would need to meet the electricity and steam load requirements of the capture process. Furthermore, accounting for emissions from the auxiliary cogeneration unit would lower the capture efficiency at Petra Nova

[167] JX Nippon Oil & Gas Exploration Corporation. *Restart of the large-scale Petra Nova Carbon Capture Facility in the U.S.* (September 2023). Available at: https://www.eneos-xplora.com/english/newsrelease/upload_files/20230913EN.pdf.
[168] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). Available at: https://www.osti.gov/servlets/purl/1608572.
[169] 90 percent x 240 MWe/610 MW = 36 percent.

further. In the 2024 CPS, by ignoring the emissions from the auxiliary cogeneration unit, the EPA failed to reasonably extrapolate the results at Petra Nova to a system using integrated steam and power. Considering these factors, the experience at Petra Nova does not support 90 percent capture as adequately demonstrated.

Comments: Some commenters cited additional examples of CO_2 capture on coal-fired steam generating units in China. Commenters cited the 150,000 metric tons of CO_2 per year Jinjie demonstration project. Commenters also cited the 500,000 metric tons of CO_2 per year Taizhou CCS project, which began operation in June 2023 and captures less than 12.5 percent of the 1000 MW EGU's total CO_2 emissions. Commenters also referenced the 1.5 million metric tons of CO_2 per year Longdong CCS project at the coal-fired Zhengning Power Plant. Captured CO_2 will be stored in geologic storage and used for EOR. The 270 MWe project has a design capture efficiency of 95 percent from a portion of the flue gas from a 1,000 MW coal-fired EGU.[170]

EPA Response: The Jinjie demonstration project began operation in June 2021 and processes less than five percent of the flue gas from one of the units at the coal-fired power plant.[171] By January 2025, the Taizhou CCS project had captured just 300,000 metric tons of CO_2, far below its design basis. While a report states that this project achieves a capture rate of 90.86 percent, detailed data (*e.g.*, operating-availability, amount of flue gas processed) is limited.[172] According to a press release, the Longdon CCS project completed a 72-hour test on September 25, 2025, but the press release did

[170]State of the Art: CCS Technologies 2025. Global CCS Institute (2025). Available at: https://www.globalccsinstitute.com/wp-content/uploads/2025/08/State-of-the-Art-CCS-Technologies-2025-Global-CCS-Institute.pdf. 27 percent of the flue gas is treated.
[171] Bongers, N. China's impressive strides towards CCUS. Low Emission Technology Australia. (2025). Available at: https://letaustralia.com.au/wp-content/uploads/Executative-Summary-Chinas-Impressive-Strides-Towards-Carbon-Capture-Utilisation-and-Storage-CCUS.pdf.
[172] Gong, H., *et al*. Taizhou 500kt per year post-combustion carbon capture demonstration project. *Clean Energy*, 9 (4). (2025). Available at: https://doi.org/10.1093/ce/zkaf011.

not contain detailed performance information.[173] Beyond that press release, no reports on the project are available. Because of the limited data available, the EPA has concluded that these projects do not support 90 percent capture as adequately demonstrated.

iii. Variations in Performance of CO_2 Capture

The determinations in the 2024 CPS assumed that the CO_2 capture system is available every hour the EGU is operational and performs at its design capture efficiency (or better) during each of those hours. The EPA finds that the Agency did not adequately account for variations in performance of CO_2 capture that would result in a lower capture efficiency. This further supports the conclusion that 90 percent CO_2 capture is not adequately demonstrated for existing coal-fired steam generating units.

In the 2024 CPS, the EPA did not account for periodic decreases in the performance of the CO_2 capture system due to solvent degradation and fouling of components between maintenance cycles. Boundary Dam Unit 3 experienced challenges with respect to solvent foaming, biological fouling, scaling, and fouling from fly-ash.[174,175] While units could take actions to address those issues, performance and capture efficiency would necessarily decrease in between treatments or maintenance (*e.g.*, fouling would steadily accumulate after cleaning). On average, the capture efficiency would therefore be less than optimal. SaskPower indicated that even after

[173] China Launches World's Largest Coal-fired Carbon Capture Project (September 29, 2025). Available at: en.sasac.gov.cn/2025/09/29/c_19886.htm.

[174] Giannaris, S., *et al.* SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. *Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies*. (2021). Available at: http://dx.doi.org/10.2139/ssrn.3820191.

[175] Pradoo, P., *et al.* Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies*. (2022). Available at: http://dx.doi.org/10.2139/ssrn.4286503.

applying such fixes, Boundary Dam Unit 3 achieved, at best, a total capture efficiency of 83 percent when the capture system was operating.[176]

Furthermore, the EPA did not adequately account for periods of startup on the operation of the capture system.[177] After absorption, thermal energy (heat) in the form of steam is required to release the CO_2 from the CO_2-rich solvent and electricity is required to power the compressor to compress the CO_2 for transport via pipeline. However, prior to substantial production of steam and electricity, major components of the capture process may be offline. Even assuming the capture system could consistently capture 90 percent CO_2 when operating, any CO_2 emitted prior to operation of the capture equipment would necessarily result in an average capture efficiency of less than 90 percent.

To consistently achieve 90 percent capture on average, the source would have to overperform during certain hours. The EPA cited results from Boundary Dam that suggested higher capture efficiencies were achieved at lower throughputs.[178] However, in its justification of the BSER, the EPA relied on an assumption that sources would operate at high capacity throughout the course of the year. If that were the case, the hypothetical higher capture efficiencies a system could potentially achieve at lower throughputs would not occur in practice. To otherwise achieve an annual average capture efficiency of 90 percent, higher instantaneous capture efficiencies likely would need to be achievable. In the 2024 CPS, the EPA cited vendor statements of pilot tests for different commercial amine solvents where operators observed higher capture efficiencies under specific conditions.[179] However, the experience at Boundary Dam shows that it would be

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[176] U.S. EPA, "Meeting with SaskPower to Discuss CCS at Boundary Dam Unit 3" (January 18, 2024). Document ID No. EPA-HQ-OAR-2023-0072-8906.
[177] 89 FR 39798, 39854, 39929 (May 9, 2024).
[178] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: https://dx.doi.org/10.2139/ssrn.4286430.
[179] 89 FR 39798, 39852 (May 9, 2024).

reasonable to anticipate that the total capture efficiency a system achieves in practice would be less than design specifications.

iv. Planned Projects

In the 2024 CPS, the EPA also previously cited planned projects and front-end engineering and design (FEED) studies.[180] [181] However, the planned projects are neither operational nor provide measured data. While the equipment for those planned projects may have been designed for 90 or even 95 percent CO_2 capture, simply designing a project for a certain percentage capture does not ensure that the project will achieve that percentage capture in practice. Boundary Dam Unit 3 did not achieve its design percentage capture, as detailed in section IV.A.1.a.i of this preamble. Therefore, because those hypothetical projects have not yet produced any data, they do not mitigate the potential underperformance of CO_2 capture, and, therefore, are not sufficient to show that 90 percent CO_2 capture is adequately demonstrated.[182] Moreover, none of the projects (for post-combustion CO_2 capture from fossil fuel-fired EGUs) with feasibility or FEED studies previously cited by the EPA have moved forward to construction.

There are no post-combustion CCS applications on fossil fuel-fired EGUs that have begun operation since the finalization of the 2024 CPS that are sufficient to support 90 percent capture as adequately demonstrated. Rather, some of the planned projects cited in the 2024 CPS either have been abandoned or have faced other challenges. Project Diamond Vault was a planned project to capture up to 95 percent of CO_2 emissions from

[180] 89 FR 39798, 39851 (May 9, 2024).
[181] *See* Chapter 4.4 and Table 13 of *Greenhouse Gas Mitigation Measures for Steam Generating Units*. Document ID No. EPA-HQ-OAR-2023-0072-9095.
[182] This includes projects for CCS on coal-fired steam generating units in West Virginia and Alaska that were recently selected for funding by DOE. *See* Project Selections for Broad Agency Announcement DE-FOA-0003605, Restoring Reliability: Coal Recommissioning and Modernization (Topic 1). Available at: https://www.energy.gov/hgeo/project-selections-broad-agency-announcement-de-foa-0003605-restoring-reliability-coal-0.

the 600 MW Madison Unit 3 at Brame Energy Center in Lena, Louisiana.[183] The FEED study and current plans for carbon capture were abandoned in late 2024.[184] Project Tundra is a carbon capture project in North Dakota at the Milton R. Young Station lignite coal-fired power plant that planned for the capture plant to treat the flue gas from the 455 MW Unit 2 and some additional flue gas from the 250 MW Unit 1 (an equivalent capacity of 530 MW in total).[185] TC Energy, a primary sponsor of Project Tundra, has since withdrawn from the project, although the project may continue to move forward depending on various factors.[186] The timeframes for several other CCS projects on coal-fired EGUs are unclear.[187]

b. Cost

The EPA has re-evaluated the costs and associated assumptions of 90 percent CCS on existing long-term coal-fired steam generating units and is finalizing the determination that the costs are not reasonable based on the rationale detailed in this section of the preamble.

i. Capacity Factor, Effective Capture Efficiency, and Other Assumptions

In the 2024 CPS, costs for CCS on existing coal-fired steam generating units were determined assuming a best-case scenario. Specifically, the cost assessment assumed sources operated at high annual capacity factors (80 percent) and that the CO_2 capture

[183] Project Diamond Vault Overview. Document ID No. EPA-HQ-OAR-2025-0124-0027.
[184] Cleco Corporate Holdings, LLC SEC Form 10Q, at 51 (August 18, 2024). Available at: https://www.sec.gov/Archives/edgar/data/18672/000108981924000026/cnl-20240630.htm.
[185] "An Overview of Minnkota's Carbon Capture Initiative—Project Tundra," 2023 LEC Annual Meeting (October 5, 2023).
[186] Power Engineering. Key partner withdraws from large-scale CO_2 capture project. Available at: https://www.power-eng.com/environmental-emissions/carbon-capture-storage/key-partner-withdraws-from-large-scale-co2-capture-project/.
[187] D. Gearino, *A Carbon Capture Project Faces a New Delay in a Year of Slow Progress for Coal Power Plants Looking for Retrofits*, Inside Climate News (December 10, 2024). Available at: https://insideclimatenews.org/news/10122024/north-dakota-coal-plant-carbon-capture-project-faces-new-delay/.

equipment was available and performing optimally every hour the EGU was operating. However, in 2023, coal-fired EGUs had an average capacity factor of 42 percent.[188] Lower capacity factors typically result in less revenue from electricity generation. Moreover, as detailed in the preceding section of this preamble, even with a design capture efficiency of 90 percent, the actual total capture efficiency over the course of the year is lower, and under some circumstances significantly lower. Consequently, less CO_2 captured (due to lower actual capture efficiency, lower EGU capacity factor, or both) results in higher costs due to reduced revenue from the IRC section 45Q tax credit.[189]

Furthermore, rather than directly considering the costs for any operation after the expiration of availability of the IRC section 45Q tax credit for existing coal-fired steam generating units in the 2024 CPS, the EPA committed to review the requirements of the emission guidelines pertaining to existing coal-fired steam generating units by January 1, 2041, and posited that other mechanisms for potential valuation of EGUs operating with 90 percent CCS could arise in the future.[190] However, those assumptions are no longer reasonable because the EPA believes that coal-fired steam generating units are now more likely to operate longer than they will be able to claim the tax credit. As noted in the June 2025 NPRM, the EPA believes that coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply.[191] A number of coal-fired steam generating units are delaying or canceling their scheduled retirements in light of increasing electricity demand, among other factors.[192]

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[188] U.S. Energy Information Administration. Electric Power Annual. Available at: https://www.eia.gov/electricity/annual/.

[189] These tax credits are currently available for a twelve-year period for facilities that commence construction before January 1, 2033, and can be used to offset tax liability. 26 U.S.C. 45Q (2025).

[190] 89 FR 39798, 39902 (May 9, 2024).

[191] *See* 90 FR 25752, 25772, 25774 (June 17, 2025).

[192] D. Proctor, *U.S. Coal Plants Get Reprieve as Market and Policies Change*, Power (February 6, 2025). Available at: https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change/.

The EPA's projections further show a substantial capacity of coal-fired steam generating units operating in the long term.[193] Based on a lower capacity factor and operation beyond 12 years, the EPA proposed that, even if the IRC section 45Q tax credit is accounted for as a reduction, the costs are unreasonable and solicited comment on the assumptions in evaluation of the reasonableness of the cost of the BSER.

Comments: Some commenters agreed with the EPA's capacity factor assumptions in the June 2025 NPRM for evaluating the cost of CCS as BSER. Other commenters stated that the 80 percent capacity factor assumed for cost calculations in the 2024 CPS was reasonable and argued that the availability of the IRC section 45Q tax credit would incentivize higher capacity factors. Commenters also argued that the EPA's June 2025 NPRM was internally inconsistent, noting that elsewhere the June 2025 NPRM stated that "coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply."[194] Some commenters disagreed with the EPA's analysis based on a capture system underperforming (*i.e.*, designed for 90 percent capture, but achieving 75 percent total capture efficiency in practice). Commenters argued that the 75 percent total capture efficiency was unjustified.

EPA Response: As detailed in section IV.A.1.a of this preamble, it is reasonable to anticipate that a capture system designed to achieve a given capture efficiency would underperform. While CCS may achieve emission reductions, evidence shows the CO_2 capture system underperforms. The capture system at Boundary Dam Unit 3 was designed to achieve 90 percent capture but achieved, at best, 63 percent total capture efficiency on an annual basis between 2015 and 2022. Under a set of assumptions that reflect the underperformance of CCS, lower capacity factors, and the limited availability

[193] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[194] 90 FR 25774 (June 17, 2025).

of the IRC section 45Q tax credit,[195] the costs are substantially higher ($62/MWh, $124/ton of CO_2 reduced) than those determined in the 2024 CPS and more than three times higher on a $/MWh basis than the costs the EPA has previously determined to be reasonable ($18.50/MWh).[196] Even assuming a higher capacity factor that reflects the average capacity factor of coal-fired steam generating units of approximately 70 percent in the updated baseline projection,[197] costs remain high ($50/ton, $25/MWh).[198] Such high costs, particularly on a $/MWh basis, are not reasonable, even considering the potential CO_2 emission reductions, and do not support 90 percent CCS as BSER.

ii. The IRC Section 45Q Tax Credit

The costs for 90 percent CCS are even higher if the IRC section 45Q tax credit is not accounted for as a reduction ($77/MWh and $155/ton).[199] In the 2024 CPS, the costs of 90 percent CCS for existing coal-fired steam generating units accounted for the IRC

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[195] These costs include the costs of capital equipment, *etc.*, consistent with 90 percent design capture rate, 63 percent actual capture rate, a fixed 40 percent capacity factor, and 15-year booklife (12 years of 45Q availability, three years without). Costs are expressed in 2019$. See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

[196] Costs are expressed in 2019$. In a variety of rulemakings, the EPA has required coal-fired EGUs to install and operate flue gas desulfurization (FGD, or wet scrubbers) to reduce their SO_2 emissions. The annualized cost of installing these controls on a representative 700 to 300 MW coal-fired steam generating unit are $14.80 to $18.50/MWh. Hence control costs that are generally consistent with these values should be considered reasonable. *See* 89 FR 39798, 39882 (May 9, 2024).

[197] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).

[198] These costs include the costs of capital equipment, *etc.*, consistent with 90 percent design capture rate, 63 percent actual capture rate, a fixed 70 percent capacity factor, and 15-year booklife (12 years of 45Q availability, three years without). Costs are expressed in 2019$. See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

[199] These costs include the costs of capital equipment, *etc.*, consistent with 90 percent design capture rate, 63 percent actual capture rate, a fixed 70 percent capacity factor, and 15-year booklife (no reduction in cost from 45Q). Costs are expressed in 2019$. See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

45Q tax credit by reducing the direct costs to the source for every ton of CO_2 reduced. The 2024 CPS assessed costs over a period consistent with the 12-year availability of the IRC section 45Q tax credit. The 2024 CPS justified that position on grounds that CAA section 111(a)(1) requires the EPA, in determining the BSER, to account for "the cost of achieving such [emissions] reduction," and asserted that this provision refers to the cost to the source rather than the societal cost. The Inflation Reduction Act (IRA) extended and expanded the IRC section 45Q tax credit and included CAA section 135(a)(6), requiring the EPA to promulgate regulations under the CAA's authorities to ensure reductions in GHG emissions. In the 2024 CPS, the EPA further stated that the IRA included legislative history stating that Congress intended to authorize the Agency to promulgate regulations under CAA section 111 to reduce GHGs from fossil fuel-fired power plants, including regulations based on CCS that assumed lower cost due to the 45Q tax credit.[200] In its proposed repeal of the 2024 CPS, the EPA reevaluated this position and proposed that reducing control costs by the amount of the tax credit is an incorrect accounting for the costs of control, and solicited comment on this position.[201]

(A) Comments and Responses

Comments: Some commenters opposed the June 2025 NPRM and stated that the EPA must account for the IRC section 45Q tax credit as a reduction when evaluating the costs of 90 percent CCS. Commenters argued that the EPA has long understood the "cost" in CAA section 111(a)(1) to refer to whether the cost to the regulated source would be too great to implement the technology.[202] Some commenters argued that counting the IRC section 45Q tax credit as a reduction in costs in the evaluation of reasonableness of the costs is the best reading of CAA section 111(a)(1), which directs

[200] 89 FR 39798, 39881 (May 9, 2024).
[201] 90 FR 25752, 25772 (June 17, 2025).
[202] Commenters cited *Portland Cement Ass'n*, 513 F.2d at 508 ("The industry has not shown inability to adjust itself in a healthy economic fashion to . . . the standards prescribed.").

EPA to "tak[e] into account the cost of achieving such reduction," when determining the BSER, not costs generally. Commenters stated the phrase "such reduction" refers to the emission reduction "achieve[ed] through the application of the best system of emission reduction." Because sources are the entities that apply the best system, the phrase "cost of achieving such reduction" is best read as focusing on costs borne by those sources, rather than broader economic impacts. Commenters argued the EPA has followed this approach since the beginning of the regulatory program.[203]

Other commenters agreed with the June 2025 NPRM and stated that the EPA should not consider the IRC section 45Q tax credit as a reduction when evaluating the cost of CCS as a potential BSER. One commenter stated that the statute requires consideration of total costs and cited the Supreme Court's decision in *Michigan*.[204] Commenters claimed that the decision held that the EPA must consider all costs, including system and indirect costs, when evaluating the reasonableness of a standard. Some commenters argued that tax credits do not reduce the cost of 90 percent CCS but simply shift those costs to taxpayers. A few commenters further stated that CAA section 111(a)(1) includes consideration of societal costs beyond those to a source's owner or operator. One commenter argued that the inclusion of "cost" in the parenthetical of CAA section 111(a)(1), along with other factors that account for societal disbenefits, suggests that the best reading of CAA section 111(a)(1) is that the EPA should not focus solely on the cost to the source when evaluating the BSER and, therefore, should not account for the IRC section 45Q tax credit as reducing costs.

[203] Commenters cited *Portland Cement Ass'n*, 486 F.2d at 388, observing that the ruling explained that the "cost" analysis is focused on equipment and operating costs and rejected an argument that a broader cost-benefit analysis evaluating impacts was required because that would "conflict with the specific time constraints imposed on the administrator."
[204] Commenters cited 576 U.S. at 752-53.

EPA Response: The EPA agrees with the commenters who stated that the 2024 CPS erred in excluding the value of the IRC section 45Q tax credit from the cost of CCS by counting the tax credit as a reduction in the cost of CCS. CAA section 111(a)(1) provides that the EPA must determine "the best system of emission reduction … (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements)." This provision does not, by its terms, limit the costs to those incurred directly by the source. Under *Loper Bright Enterprises v. Raimondo*, 603 U.S. 369 (2024), the best interpretation of this provision is that the costs include the full costs of the controls (*i.e.*, without reduction by the amount of the IRC section 45Q tax credit). Under the justification in the 2024 CPS for considering the IRC section 45Q tax credit, if a cost was passed on to the public through a large tax credit or other similar subsidy, and that transfer was counted as a reduction, then much more expensive controls would be considered reasonable as long as the cost of those controls were passed on to the public. As commenters noted, the tax credit does not eliminate costs, it simply transfers costs to the U.S. taxpayer. Thus, the costs paid by the U.S. taxpayer, in the form of the reduction in tax receipts due to the IRC section 45Q tax credit, are part of "the cost of achieving [the emission] reduction," under CAA section 111(a)(1). As commenters also noted, this interpretation treats "costs" as consistent with the other factors that CAA section 111(a)(1) directs the EPA to consider because those other factors are not limited to the source. Specifically, CAA section 111(a)(1) directs the EPA to consider "nonair quality health and environmental impact[s]" that affect the public and "energy requirements," which include effects on the broader energy system.

Comments: Commenters argued that counting the IRC section 45Q tax credit as a reduction in costs is consistent with Congressional intent. Commenters stated that Congress enacted the IRC section 45Q tax credit specifically to encourage CCS deployment because Congress had determined such deployment as sufficiently valuable to justify the cost, and that Congress amended the CAA in the IRA and directed the EPA to regulate with the expanded tax incentives of the IRA in mind.[205] Commenters stated that if Congress wants to keep a federal funding program from affecting a BSER determination under CAA section 111, Congress would include legislative text stating so, as Congress similarly did for the funding provided as part of the Energy Policy Act of 2005 (EPAct05). Commenters note that no similar provision exists for the IRC section 45Q tax credit. Some commenters took issue with the June 2025 NPRM's observation that there was pending legislation that would have ended the tax credit. Commenters observed that, rather than eliminate the tax credit, Congress in the OBBBA expanded the tax credit by increasing the value for CO_2 used for EOR and implementing a more favorable inflation adjustment.

EPA Response: CAA section 135(a)(6), as adopted by the IRA, provides $18 million to the EPA "to ensure that reductions in [GHG] emissions are achieved through the use of the existing authorities of [the CAA], incorporating [an] assessment" that the EPA is required to conduct of reductions in GHG emissions from changes in domestic electricity generation and use through fiscal year 2031.[206] However, this provision does not mention CAA section 111 and thus by its terms is not specific enough to indicate Congressional intent to authorize the EPA to promulgate CAA section 111 regulations based on CCS as the BSER and, in doing so, to account for the cost of CCS after reductions by the IRC section 45Q tax credit.

The EPA further disagrees with commenters' objection that if Congress had intended for the Agency not to consider the reduction in control costs due to the IRC section 45Q tax credit, Congress would have explicitly said so. Commenters note that in the EPAct05, Congress included provisions explicitly precluding the EPA from

[205] Commenters cited the Inflation Reduction Act, Pub. L. 117-169, section 13104, 136 Stat. 1818, 1924-29 (2022).
[206] 42 U.S.C. 7435(a)(6).

considering projects that included emissions controls that had been funded through EPAct05 in determining whether those controls are adequately demonstrated under CAA section 111. Absent such provisions, CAA section 111 would have allowed the EPA to consider those projects. As noted in this section of the preamble, the best interpretation of CAA section 111 is that the EPA must consider the costs of the control device, whether the costs are incurred by the facility or the taxpayer through the IRC section 45Q tax credit, and that if Congress had intended that the EPA not to do so, Congress would have included a specific provision to that effect.

Comments: Some commenters stated that in *Michigan v. EPA*, the U.S. Supreme Court reiterated that in promulgating rulemakings, Federal agencies "are required to engage in 'reasoned decisionmaking,'"[207] and that "ordinarily requires paying attention to the advantages and the disadvantages of agency decisions."[208] Commenters stated that the failure of the EPA to consider the burden on the average U.S. taxpayer of the IRC section 45Q tax credit constituted a failure of reasoned decisionmaking.

EPA Response: The EPA agrees with the commenters, and that considering the burden on U.S. taxpayers tilts this action against adopting CCS as the BSER. The EPA is finalizing that the IRC section 45Q tax credit should not be accounted for as a reduction in costs to the source when evaluating the reasonableness of the costs of the BSER. Without taking into account the IRC section 45Q tax credit as a reduction, the costs of 90 percent CCS as BSER ($77/MWh and $155/ton) are unreasonable for long-term coal-fired steam generating units.[209]

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[207] 576 U.S. at 750 (citing Allentown Mack Sales & Service, Inc. v. NLRB, 522 U.S. 359, 374 (1998)).

[208] *Id.* at 753 (emphasis omitted).

[209] These costs include the costs of capital equipment, *etc.*, consistent with 90 percent design capture rate, 63 percent actual capture rate, a fixed 70 percent capacity factor, and 15-year booklife (no reduction in cost from 45Q). Costs are expressed in 2019$. See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

c. Infrastructure

The large, widespread, and third-party infrastructure needed to support CCS is unique as compared to other BSER control technologies the EPA has historically analyzed and adopted under CAA section 111. In the 2024 CPS, the EPA determined that the capture, pipeline, and sequestration infrastructure necessary for the affected sources to meet the standards could be deployed by the compliance date of January 1, 2032. However, that position relied on incorrect assumptions in an unrealistic, best-case scenario that experience has already shown to be inaccurate. Therefore, the EPA proposed that the degree of emission limitation is not achievable because it is unlikely that the necessary infrastructure can be deployed by that compliance date.

In general, the capture, pipeline, and sequestration infrastructure necessary for 90 percent CCS for the fleet of existing coal-fired steam generating units does not currently exist. The necessary infrastructure would need to be broadly deployed, and there are challenges that exist for sources (*e.g.*, pipeline permitting and right-of-way) that may not be able to be resolved. It is highly unlikely, if not impossible, that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, and the EPA is therefore finalizing that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable.

With respect to the timeline for implementing infrastructure that does not currently exist, the EPA is revising both the weight the Agency should place on such future projections and its future projections with respect to 90 percent CCS. In the 2024 CPS, the Agency took the general position that an adequately demonstrated control technology could be selected as the BSER, and therefore the basis for a standard, so long as implementation at the scale required for compliance to be feasible could be projected to a date certain. However, upon further consideration and in light of public comments, the EPA is now clarifying that the uncertainty associated with such projections is a reason to disfavor the selection of such BSERs. The eight-year review cycle laid out in CAA section 111(b)(1)(B) is a signal that Congress thought the BSER generally should be capable of being implemented within eight years such that the EPA's review can meaningfully assess the success of the prior rule.[210,211] In the 2024 CPS, the EPA estimated that it would take approximately seven years to implement 90 percent CCS for existing coal-fired units. The 2024 CPS also provided an exemption under which sources were not subject to the rule if they closed by the date that compliance with the standard based on 90 percent CCS would have commenced (January 1, 2032). However, as explained in section IV.A.1.c of this preamble, the EPA is now determining that the January 1, 2032 compliance date for 90 percent CCS for existing coal-fired steam generating units was overly optimistic. That is, implementing 90 percent CCS would take longer than the seven years provided in the 2024 CPS, bringing it close to CAA section 111(b)(1)(B)'s eight-year benchmark, if not exceeding it.

With respect to the infrastructure itself, the EPA has, upon further review, determined that the novelty of a BSER predicated on widespread infrastructure operated by third parties warns strongly against its selection. Much of the necessary CCS infrastructure requires the involvement, both for initial development and ongoing performance, of external third parties over whom the owners and operators of regulated facilities have limited control. Each of the three components of CCS—capture, transport,

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[210] CAA section 111(b)(1)(B) provides that the Administrator shall review and, if appropriate, revise NSPS at least every eight years. 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 such standard." 42 USC § 7411(b)(1)(B). The EPA believes that the eight-year review cycle is relevant to existing sources regulated under CAA section 111(d) because it speaks to the appropriateness of a system of emission reduction as the BSER, and the BSER considerations under CAA section 111(a)(1) apply to both new and existing sources.
[211] In the event a system of emission reduction would take longer than eight years to implement, the EPA should take a hard look at whether it in fact qualifies as the BSER under CAA section 111(a)(1). The result of this inquiry may depend on whether other, less time-intensive options are available.

and storage—entail distinct infrastructure projects completed and operated in most instances by different sets of third parties, and all three components would need to be timely completed by those different sets of third parties without delay for owners and operators to be able to implement the CCS requirements by the January 1, 2032, compliance date. Construction of a CO_2 capture facility requires years of engineering analysis by third-party experts before ground can be broken and installation of the necessary equipment can commence.[212] Development of a capture facility also includes entering into necessary agreements and procuring permits through processes that may be governed by multiple jurisdictions, including but not limited to federal and state permitting authorities. And construction itself takes two or more years and involves many different activities that require a range of expert third parties.[213] In addition to the CO_2 capture facility, CCS also requires implementation of CO_2 pipeline infrastructure and CO_2 injection and storage infrastructure which involves reliance on engineers, geologists, construction firms, and permitting authorities, at least some of whom are likely separate from those involved in design and construction of the capture facility, as well as being outside of the electricity generation sector.

A BSER based on 90 percent CCS thus requires involvement, at multiple steps, of a complex web of experts and practitioners across a wide range of disciplines, many of whom may not be part of the regulated source category, or even the broader industry of which it is part, *i.e.*, the electric power industry. The implication is that these third parties are not subject to the same regulatory impetus as the owner or operator of a coal-fired steam generating unit that would be subject to requirements under the 2024 2024 CPS. The scale of the ancillary infrastructure required to support implementation of 90 percent CCS and the multitude of parties outside of an owner or operator's control at multiple

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[212] Sargent & Lundy, *CO_2 Capture Project Schedule and Operations*, Document ID No. EPA-HQ-OAR-2023-0072-9095, at 2-3 (April 2024).
[213] *Id.* at 3-4.

steps of the process that are necessary to successfully design, permit, construct, test, and operate a CCS system makes it unreasonable to base federally enforceable requirements on the presumption of a best-case scenario for implementation when tardy- or non-performance by a single party has the potential to cause or exacerbate delays that ripple through the deployment of the CCS system.

The tenuousness of timely compliance given the scope of the requisite infrastructure for 90 percent CCS, coupled with the novelty of CCS and the need for a large number of third parties, is especially apparent when it is contrasted with air pollution control technologies that have been in widespread use in the power sector for decades, such as scrubbers for SO_2 emissions and selective catalytic reduction (SCR) for NO_X emissions.[214] Those latter control technologies do not rely on extensive pipeline and sequestration infrastructure. In contrast, the infrastructure to implement CO_2 capture in the power sector at a large scale is extensive, relatively new,[215] and involves a large collection of parties and activities necessary for design, permitting, construction, and implementation. All this compounds the likelihood of delays in implementation as parties work through necessary learning processes, which further supports the unreasonableness of the 2024 CPS's aggressive compliance timeframe. To be sure, CCS has been employed in some industries for certain limited purposes. However, in those instances, CCS has not been required by federal regulation under enforceable timelines or at a

[214] *See, e.g.*, 44 FR 33580, 33580 (June 11, 1979) (promulgating standards of performance for SO_2 emitted from new, modified, and reconstructed fossil fuel-fired steam generating EGUs under CAA section 111(b) based on use of scrubbers); 63 FR 49442, 49445 (Sept. 16, 1998) (promulgating standards of performance for NO_X emitted from new fossil fuel-fired steam generating units under CAA section 111(b) based on use of SCR).

[215] While CCS has a longer history of implementation in other industries, such as ethanol production, it has not been broadly deployed in the power sector at the capture rates contemplated in the 2024 CPS. Similarly, while the 2015 NSPS for new coal-fired power plants established a standard of performance based on partial-CCS, 80 FR 64510, 64545 (Oct. 23, 2015), no new coal-fired power plants have been constructed that would be subject to this standard. Therefore, the power sector's experience with CCS has been relatively limited compared to other, similarly complex pollution controls.

similar nationwide scale, meaning that any non-performance by third parties has not resulted in noncompliance with federally enforceable obligations.

In reaching these conclusions, the EPA notes that CAA section 111 anticipates analyses and regulatory requirements that turn on actions by the regulated source. Pursuant to CAA section 111(a)(1), the Agency must promulgate standards that "reflec[t] the degree of emission limitation achievable through the *application* of the [BSER]," and the resulting emission standards apply, in turn, to the regulated source. Consistent with the EPA's historical understanding, this language is most naturally read as tying the BSER to results that are achievable through the source's application of the selected control technology. While sources commonly rely on third parties in the normal operation of their business, the extensive infrastructure requirements for CCS, coupled with the novelty of the control technology and the high level of dependence on third parties, undermines the ability of sources to achieve the CCS-based emission standards. If any third party provider responsible for any of the many links in the CCS infrastructure chain fails to develop the necessary infrastructure in a particular area, is delayed in such development for any reason, or ceases operation for any reason, the source would no longer be able to comply. These circumstances are different in kind from other BSERs that entail substantially less novel infrastructure.

The EPA is thus finding that the 2024 CPS erred by not considering the extent of the ancillary infrastructure and reliance on third parties needed for 90 percent CCS to be deployable at scale. This lapse is especially salient given the novelty of CCS at this scale and applied to this particular sector. These considerations provide further support for the conclusion that the January 1, 2032, compliance date and the degree of emission limitation are unachievable.

Comments: Some commenters stated that 90 percent CCS is achievable because the necessary infrastructure can be deployed by the compliance deadline. Commenters reiterated the arguments the EPA previously made in the 2024 CPS, including asserting that the timeline for deployment of capture based on the Sargent and Lundy report was achievable.[216] Commenters also stated that sequestration potential is broadly available, and that the 2024 CPS was premised on smaller, often intrastate CO_2 pipelines from the source to those storage sites. Commenters also stated that the EPA has made significant progress toward granting additional States primacy over Class VI injection wells for geologic storage of CO_2.[217] [218]

Other commenters stated that 90 percent CCS is not achievable because the necessary infrastructure cannot be deployed fast enough to meet the compliance deadline. Commenters argued that the timeline for deployment of the capture equipment would take longer than detailed in 2024 CPS. Commenters asserted that FEED studies can require more than 12 months, and DOE FEED studies can require even longer due to additional reporting requirements. Commenters stated that deployment of a capture facility could take up to eight to 10 years. Some commenters noted that permitting for CO_2 pipelines varies by State, and that some States have restrictive policies for CO_2 pipelines. Some commenters stated that the Pipeline Hazardous Materials Safety Administration is still working on updated regulations for CO_2 pipeline safety.

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[216] Sargent & Lundy, *CO_2 Capture Project Schedule and Operations*, Document ID No. EPA-HQ-OAR-2023-0072-9095, at A-1 (April 2024).
[217] Class VI wells are used to inject CO_2 into deep rock formations and are regulated by the EPA under the Underground Injection Control (UIC) Program as authorized by the Safe Drinking Water Act. Available at: https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide#authorities.
[218] Injection wells are overseen by either a state or tribal agency or one of EPA's regional offices. States and tribes may apply for primary enforcement responsibility to implement the UIC program. Primary enforcement responsibility, often called primacy, refers to State, territory, or Tribal responsibilities associated with implementing EPA approved UIC programs. A State, territory, or Tribe with UIC primacy, or primary enforcement responsibility, oversees the UIC program in that State, territory, or Tribe. Available at: https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide.

EPA Response: In general, the capture, pipeline, and sequestration infrastructure necessary for 90 percent CCS for the fleet of existing coal-fired steam generating units does not currently exist.

The equipment for the capture of CO_2 takes time to design, permit, and install. In the 2024 CPS, the EPA assumed an aggressive, unrealistic timeline for deployment of capture equipment. The EPA's timeline for installation of capture equipment included a 12-month FEED study in place of an 18-month FEED study, based off the more aggressive project schedule in a report developed by Sargent and Lundy.[219] The EPA further abbreviated that schedule by two months based on its own assumptions by shortening the duration for commercial arrangements from nine months to seven months, assuming sources immediately begin sitework once permitting is complete, and accounting for 13 months (rather than 14) for startup and testing.[220] However, those assumptions ignore any potential delays and do not reflect what is actually achievable .[221] The necessary infrastructure would need to be broadly deployed, and there are significant challenges that could exist for sources that would need to be resolved.

Regarding transport of CO_2, there is no existing network of CO_2 pipelines with the capacity capable of meeting the demands in the 2024 CPS. There are approximately 5,000 miles of CO_2 pipelines operational in the U.S.[222] [223] However, they are largely not located near existing coal-fired sources and additional pipelines would take time to

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[219] Sargent & Lundy, *CO_2 Capture Project Schedule and Operations*, Document ID No. EPA-HQ-OAR-2023-0072-9095, Attachment 17 (April 2024).
[220] 89 FR 39798, 39875 (May 9, 2024).
[221] *See* Nat'l Lime Ass'n v. EPA, 627 F.2d 416, 432-33 (D.C. Cir. 1980) (EPA must explain how the standard is "achievable under the range of relevant conditions" which sources may experience).
[222] Congressional Research Service. Carbon Dioxide Pipelines: Safety Issues, CRS Reports (June 3, 2022). Available at: https://www.congress.gov/crs-product/IN11944.
[223] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems (May 1, 2026). Available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-hazardous-liquid-or-carbon-dioxide-systems.

deploy. Planned CO_2 pipelines continue to face delays due to several factors, including state permitting and the challenges associated with eminent domain authority and negotiating rights-of-way. For example, after promulgation of the 2024 CPS, Summit Carbon Solutions paused their application for a pipeline in South Dakota after the State banned eminent domain for CO_2 pipelines.[224] [225] A similar law is progressing through the Iowa legislature.[226]

Furthermore, while the U.S. has broad availability of the geologic formations that are potentially suitable for CO_2 sequestration, existing storage infrastructure for sequestration of CO_2 is limited. Underground CO_2 storage is governed by the Underground Injection Control program as authorized by the Safe Drinking Water Act.[227] Under that program, Class VI wells are used to inject CO_2 thousands of feet underground for geologic storage, and are permitted by the EPA. There are 18 Class VI wells that have been permitted by the EPA and there are six states that have primary enforcement authority (Arizona, Louisiana, North Dakota, Texas, West Virginia, and Wyoming).[228] In the 2024 CPS, the EPA based assumptions on the availability of "potential" storage sites. Time is required to characterize those sites to ensure the geology in the project area can receive and contain the CO_2 within the zone where it will be injected. However, the nearest available "potential" site may, after further investigation, not ultimately be

[224] J. Chilson, *Summit pauses CO_2 pipeline application in South Dakota*, South Dakota Public Broadcasting (March 12, 2025). Available at: https://www.sdpb.org/business-economics/2025-03-12/summit-pauses-co2-pipeline-application-in-south-dakota.
[225] An Act to prohibit the exercise of eminent domain for a pipeline that carries carbon oxide, South Dakota Legislature House Bill 1052, 100th Session, H.J. 475 (March 6, 2025). Available at: https://sdlegislature.gov/Session/Bill/25581.
[226] C. Koons, *House votes to ban eminent domain for CO_2 pipelines*, Iowa Capital Dispatch (March 26, 2025). Available at: https://iowacapitaldispatch.com/2025/03/26/house-votes-to-ban-eminent-domain-for-co2-pipelines/.
[227] EPA. Class VI Wells used for Geologic Sequestration of Carbon Dioxide (May 14, 2026). Available at: https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide#ClassVI_PermittingProcess
[228] EPA. Current Class VI Projects under Review at EPA. Accessed June 2, 2026. Available at: https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.

suitable, *e.g.*, if faults or fractures are detected during site characterization. More time would then be required to find and characterize a new storage site, if another suitable site is even available. The timeline in the 2024 CPS did not take into consideration the prospect of project developers having to pivot to a different storage site should the initial site prove unsuitable. Development of planned storage sites may also face delays due to permitting and other issues. These challenges to deployment of CCS provide further support to the conclusion that the January 1, 2032, compliance date and degree of emission limitation are unachievable.

Moreover, a greater number of sources would likely be subject to CCS-based requirements than previously anticipated. Those sources would be competing to build CCS infrastructure, exacerbating any potential schedule delays or supply constraints, further limiting the achievability of the EPA's infrastructure timeline in the 2024 CPS. As the EPA noted in the June 2025 NPRM, the Agency believes that coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply due to increasing electricity demand.[229] A number of coal-fired steam generating units are delaying or canceling their scheduled retirements in light of this increasing demand, the changes in tax incentives for various types of electricity-generating resources in the OBBBA, and Administration actions to support the continued operation of coal-fired capacity.[230] [231] Recent changes in the U.S. electricity market affect the amount of coal-fired steam generating units operating in the long-term, as described in section III.C of this preamble, including increased electricity demand from data centers and scaled back tax credits for renewable generation under the OBBBA. The EPA now

[229] *See* 90 FR 25752, 25772, 25774 (June 17, 2025).
[230] D. Proctor, *U.S. Coal Plants Get Reprieve as Market and Policies Change*, Power (February 6, 2025). Available at: https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change/.
[231] *See, e.g.*, U.S. Department of Energy, 2026 DOE 202(c) Orders. Available at: https://www.energy.gov/ceser/2026-doe-202c-orders.

projects that more existing coal-fired EGUs will operate in the long term and more base load NGCCs will be built than previously anticipated.[232] Specifically, at the end of 2024 there were 174 GW of coal-fired EGUs active in the power sector nationwide.[233] The baseline 2024 analysis for the 2024 CPS projected that, absent requirements, approximately 40 GW of coal capacity would still be active by 2040.[234] Therefore, the 2024 CPS considered the viability and reasonableness of installing and operating CCS at 40 GW of coal capacity. However, the EPA now projects that, as a baseline, approximately 100 GW of coal capacity will be active in 2040.[235] Similarly, under the analysis conducted for the 2024 CPS, the EPA projected approximately 26 GW of incremental NGCC capacity additions by 2035.[236] Under the 2025 analysis, absent the requirements of 2024 CPS, the EPA projects approximately 155 GW of new NGCC builds by 2035. Based on the EPA's updated analytics a much larger number of EGUs would be subject to CCS-based standards than previously estimated in the 2024 CPS. The large amount of CCS infrastructure necessary would likely exacerbate any potential schedule delays or supply chain constraints. Deploying the necessary infrastructure for the affected fleet by the January 1, 2032, compliance date is therefore further unlikely.

Considering these factors, it is unlikely the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, and the EPA is therefore finalizing that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable.

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[232] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[233] U.S. Energy Information Administration. EIA Power Monthly (December 2024). Available at: https://www.eia.gov/electricity/monthly/archive/december2024.pdf.
[234] Document ID No. EPA-HQ-OAR-2023-0072-8913. Table 3-14.
[235] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[236] Document ID No. EPA-HQ-OAR-2023-0072-8913. Table 3-14.

d. Conclusion

Because the EPA is finalizing that 90 percent CCS is not adequately demonstrated as the BSER and that the cost of 90 percent CCS for long-term coal-fired steam generating units is not reasonable, the Agency is finalizing the determination that 90 percent CCS is not the BSER for long-term coal-fired steam generating units. Furthermore, because it is extremely unlikely that the extensive infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA is finalizing a determination that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable. Additionally, the challenges posed by the scope of the infrastructure are heighted by the involvement of numerous parties external to the owners and operators of the regulated facility, which complicates deployment and exacerbates delays that thus provides further support for the conclusion that the January 1, 2032 compliance date and the degree of emission limitation are unachievable.

Moreover, the EPA is concluding that in light of current information concerning sources' inability to comply with 90 percent CCS by 2032, retaining 90 percent CCS as the BSER for existing coal-fired steam generating units that did not commit to retire before January 1, 2039, coupled with an exemption from the rule for sources that agreed to retire before January 1, 2032, would be a form of generation shifting prohibited by *West Virginia* under the circumstances here.[237] Specifically, because updated projections demonstrate that compliance with 90 percent CCS generally is not feasible by 2032, sources have only one remaining option: retirement by 2032. Failing to revise the standard under these circumstances would therefore amount to forced closures in anticipation of other forms of power generation by facilities not subject to the at-issue 2024 CPS requirements.

[237] 597 U.S. at 735.

In the immediate aftermath of *West Virginia*, the EPA initially focused on the Supreme Court's statement that generation shifting could sometimes be a consequence of regulatory requirements under CAA section 111.[238] The Agency believed at the time that the lesson of *West Virginia* was that generation shifting was appropriate as a *result* of regulation, so long as the regulation did not explicitly *require* it.[239] The EPA therefore selected 90 percent CCS and 40 percent natural gas co-firing, coupled with an exemption contingent on unit retirement by 2032, based on the belief that unit closure was an appropriate consequence so long as facilities could also choose to comply with the standards.

However, as detailed in section IV of this preamble, the EPA is now determining that the predictions and analyses underlying 90 percent CCS were overly optimistic. The EPA now concludes that requiring sources either to close by 2032 or comply with 90 percent CCS requirements that have now been determined to be unreasonable and impracticable essentially presents a Hobson's choice. That is, because the EPA's predictions regarding 90 percent CCS have now been determined to be overly optimistic, retaining the 2024 CPS would effectively force generation shifting by leaving regulated sources with no alternative to closure by the compliance deadline in 2032.

Consequently, the EPA is finalizing repeal of the requirements in emission guidelines pertaining to long-term coal-fired steam generating units. As discussed in this section of the preamble, the EPA is addressing only CCS with 90 percent capture and implementation by January 1, 2032, because these were the requirements under the 2024 CPS. This action does not finalize any potential alternative BSERs or implementation timeframes such as CCS with lower rates of capture or a later compliance date. The EPA

[238] *See id.* at 731 n.4 (noting that "there is an obvious difference between (1) issuing a rule that may end up causing an incidental loss of coal's market share, and (2) simply announcing what the market share of coal, natural gas, wind, and solar must be").
[239] *See, e.g.*, 91 FR 39798, 39899 (May 9, 2024).

considered whether to analyze and promulgate potential alternatives and determined it is not necessary to do so under the circumstances presented here.

2. Natural Gas Co-Firing-Based Requirements for Existing Medium-Term Coal-Fired Steam Generating Units

In the 2024 CPS, the EPA determined the BSER for existing medium-term coal-fired steam generating units to be 40 percent natural gas co-firing. Natural gas co-firing can require installation of new gas burners and related boiler modifications. Natural gas co-firing also requires construction of natural gas pipeline infrastructure to supply the necessary amount of natural gas to the unit. The EPA argued in the 2024 CPS that natural gas co-firing qualifies as the BSER for medium-term coal-fired units because, among other things, it does not result in unreasonable adverse consequences related to energy requirements. In the 2024 CPS, the EPA further argued that the degree of emission limitation based on application of the 40 percent natural gas co-firing BSER to the affected sources was achievable by the January 1, 2030, compliance date, considering the time necessary to deploy the necessary natural gas pipeline infrastructure.

The EPA reevaluated the record for and the Agency’s determinations in the 2024 CPS and subsequently proposed that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units based on the potential for significant adverse consequences related to energy requirements. The EPA also proposed that 40 percent natural gas co-firing cannot qualify as the BSER because it constitutes impermissible generation shifting. Finally, the EPA further proposed to determine that the degree of emission limitation based on 40 percent natural gas co-firing is not achievable because it is unlikely that the pipeline infrastructure necessary can be deployed by the compliance date of January 1, 2030. Consequently, the EPA proposed to repeal the requirements for medium-term coal-fired steam generating units.

The EPA is finalizing the determination that 40 percent natural gas co-firing is not the BSER for medium-term coal-fired steam generating units and is repealing the requirements for those sources on that basis. In this section of the preamble, the EPA details the three bases for this determination. The first basis discussed here – that 40 percent natural gas co-firing represents impermissible generation shifting – is sufficient to preclude it from qualifying as the BSER. However, the EPA is also providing two additional bases that provide additional support for this conclusion.

a. 40 Percent Natural Gas Co-firing is Generation Shifting

The EPA is finalizing its proposed interpretation that 40 percent co-firing with natural gas is not the BSER for existing medium-term coal-fired steam generating EGUs because it constitutes generation shifting and is therefore beyond the EPA's authority to require under CAA section 111. In *West Virginia*, the Supreme Court held that a "system of emission reduction" under that section cannot include a forced shift of nationwide electricity generation from one type of energy source to another.[240] That is, the BSER cannot be based on generation shifting. In discussing whether the EPA could effect generation shifting through at-the-source measures by, *e.g.,* "simply requiring coal plants to become natural gas plants," the Court stated that "EPA has never ordered anything remotely like that, and we doubt it could." [241]

In the 2024 CPS, the EPA considered whether co-firing natural gas in a coal-fired boiler would constitute generation shifting and concluded that it would not. There, the Agency argued that, in contrast to impermissible generation shifting, 40 percent natural gas co-firing constitutes at-the-source fuel switching, which is a "traditional pollution control measure" as recognized by the Supreme Court in *West Virginia.*[242] The EPA

[240] 594 U.S. at 734-35.
[241] *Id.* at 728 n.3.
[242] U.S. EPA, Response to Comments Document (April 2024). Chapter 2.7.2, page 101-02. Document ID No. EPA-HQ-OAR-2023-0072-8914.

further explained in the 2024 CPS that the Agency interpreted the Court's statements in footnote 3 of that opinion as referring to a complete transformation of a coal-fired unit to a 100 percent natural gas-fired unit and contrasted such complete repowering with natural gas co-firing at 40 percent.[243]

The EPA has reexamined the question of whether 40 percent natural gas co-firing is impermissible generation shifting and has now determined that requiring a utility to use a completely different fuel type runs counter to the Supreme Court's decision in *West Virginia*. Critically, in that decision, the Court found that the EPA lacks authority to decide the appropriate share of different types of electricity generation on a nationwide basis.[244] Requiring a significant portion of the coal-fired fleet to become a different type of electricity generating resource – a hybrid coal and gas-fired fleet that relies on a different set of fuels – has the same effect of dictating the market shares of the different fuel types that comprise the nation's energy supply. The fact that this forced shift would occur within individual sources as opposed to across sources in the electricity generation sector does not rebut this conclusion.

Moreover, a coal-fired steam generating EGU is a fundamentally different type of plant than a steam generating EGU that fires both coal and natural gas. This is evidenced by the modifications and new infrastructure needed to turn a coal-fired EGU into a hybrid coal and gas-fired EGU, including modifications to or additions of burners to the boiler and potential changes to steam superheaters, reheaters, and economizer heating surfaces. The EPA believes that requiring a coal plant to turn itself into a different type of plant in order to burn a completely different fuel (*i.e.*, natural gas) belies the Agency's earlier assertions that 40 percent natural gas co-firing is fuel switching akin to burning lower sulfur coal in a coal-fired EGU or ultra-low sulfur diesel in a stationary compression

243 *Id.*
244 *West Virginia*, 594 U.S. at 728.

ignition internal combustion engine. In these examples, a source is merely using a particular type of the fuel that the source was always intended to use, as opposed to a different fuel entirely. Therefore, the EPA is finalizing the finding that a BSER based on forcing a coal-fired EGU to become a partially natural gas-fired steam generating units shifts that unit's generation from coal to natural gas and is impermissible under the Court's precedent because it is an attempt to dictate the market share of coal versus natural gas.

The EPA acknowledges that this is a change in position from its earlier interpretation in the 2024 CPS that 40 percent natural gas co-firing is not generation shifting. As explained in the preceding discussion, the Agency believes its updated interpretation of *West Virginia* and its application to natural gas co-firing is the best one because it recognizes the distinction between traditional fuel switching and requiring a switch to different type of fuel. No party will have relied on the EPA's earlier interpretation in the 2024 CPS, given that that regulatory framework was never implemented.

Comments: Many commenters supported the EPA's proposed interpretation that natural gas co-firing constitutes impermissible generation shifting. Commenters stressed that generation shifting occurs whenever a facility is required to switch from burning one type of fuel to an entirely different type of fuel, regardless of the amount or percentage of co-firing required, because the EPA lacks authority either to require a plant to change to a different fuel type or to require it to become a different type of plant (*i.e.*, a hybrid coal and gas plant). Commenters asserted that 40 percent co-firing would require transformation into a different type of source because co-firing natural gas in a coal-fired boiler entails changes to that boiler that could include modifications to millions of dollars of equipment and additional costs associated with pipeline infrastructure needed to support co-firing.

Other commenters opposed to the EPA's interpretation that 40 percent natural gas co-firing is generation shifting argued that natural gas co-firing is a form of fuel switching, which the EPA has historically relied on under CAA section 111. Commenters contrasted fuel switching, a traditional technology-based control measure focused on improving the performance of individual sources, with the generation shifting described by the Supreme Court in *West Virginia*, further asserting that co-firing does not entail a transformative expansion in the Agency's regulatory authority. Commenters explained that any new infrastructure and costs associated with natural gas co-firing are accounted for in the EPA's evaluation of the system's cost, which is a separate factor in the BSER analysis. Additionally, commenters asserted that it is common for a CAA section 111 standard to require extensive modifications to a plant, although the modifications associated with co-firing are relatively minor and far less extensive than those required for other control strategies at coal-fired plants, such as flue gas desulfurization or selective catalytic reduction.

Moreover, according to the commenters, co-firing does not involve the type of grid-wide reshuffling that *West Virginia* prohibits, either in concept or practice. There is no emissions or generation cap on affected sources, and the EPA does not assume any change in generation at co-firing sources. Therefore, commenters argued that the BSER is not premised on a shift of generation from co-firing sources to other sources. In addition, EPA's compliance modeling did not predict such a shift. Commenters also argued that fuel-switching is not generation shifting because a coal plant that is co-firing with 40 percent natural gas does not cease to exist as a coal plant, unlike the generation shifting addressed in *West Virginia*. Further, the EPA has always treated coal- and gas-fired steam generating EGUs as part of the same source category because the underlying type of source burning the fuel (a steam generating utility boiler) is the same, even though co-firing would require the use of some amount of a different fuel (natural gas instead of coal).

EPA Response: The EPA disagrees that co-firing natural gas in a coal-fired boiler is akin to the traditional pollution control measure under CAA section 111. As noted in this section of the preamble, natural gas co-firing is distinguishable from switching to lower sulfur coal or lower sulfur diesel, or from requiring a source to limit itself to one type of fuel. The EPA takes no position in this rule about these forms of fuel switching vis-à-vis *West Virginia*. But the EPA is, in this final rule, finding that it is not permissible for a BSER to be based on the use of an entirely different fuel from what a source was designed and configured to accept. Given that modifications are necessary to accommodate co-firing at 40 percent, this level of co-firing, in particular, is distinct from the traditional forms of fuel switching that the EPA has employed under CAA section 111. The cost of those modifications is not as relevant as the fact that they occur: The EPA considers the need for modifications as part of determining whether 40 percent co-firing is an appropriate system of emission reduction, as opposed to whether it is the *best* system of emission reduction based on cost and the other factors of CAA section 111(a)(1). That is, because a coal-fired source must transform itself to co-fire natural gas at 40 percent, such co-firing is not fuel switching but is rather shifting generation to a different type of source. While commenters countered that natural gas co-firing is not generation shifting because the source remains a fossil fuel-fired steam generating boiler that continues to fire some amount of coal, the EPA does not believe that it is necessary to shift generation from a boiler to a combustion turbine in order to effectuate impermissible generation shifting. Under the commenters' logic, the EPA's requiring 99 percent natural gas co-firing would still not be considered shifting generation because one percent would still be some amount of coal still being utilized. Rather, the EPA's position is that generation shifting occurs when a system of emission reduction requires a source to use an entirely different type of fuel, particularly when the source was not designed to accept the new type of fuel. The effect of such an approach is that the EPA effectively dictates the fuel mix used in the nationwide energy system, which the Supreme Court held in *West Virginia* the EPA is not permitted to do.

b. Energy Requirements

Even if 40 percent natural gas co-firing could be evaluated as a potential BSER, which it cannot be for the reasons discussed in section IV.A.2.a of this preamble, the EPA further determines that the adverse impacts on the energy system are unreasonable and therefore that 40 percent co-firing cannot be the BSER for medium-term coal-fired EGUs. As part of determining the BSER, the EPA considers energy requirements.[245] As discussed in section II.C.3 of this preamble, energy requirements may include the impacts, if any, of the air pollution controls on the source's own energy needs.[246] The EPA may further assess, as part of the energy requirements consideration, any impacts of a system of emission reduction on the energy system on a sector-wide, regional, or national basis, as appropriate.[247] As part of such assessment, the EPA has considered potential adverse impacts on the reliability of the bulk power system and its ability to deliver affordable and consistent electricity to end users.[248] Similarly, the EPA has considered whether potential BSERs might have adverse impacts on the supply or cost of natural gas, which is used in many applications throughout the nation's energy system, including for electricity generation, industrial applications, and transportation.[249] In this

[245] 42 U.S.C. 7411(a)(1).
[246] *See, e.g.*, 91 FR 1910, 1937 (January 15, 2026) (energy requirements consideration includes auxiliary/parasitic load requirements to run a potential BSER control for fossil fuel-fired combustion turbines).
[247] *See, e.g.*, *Sierra Club* , 657 F.2d at 330 (interpreting energy requirements factor as including consideration of effects "on the grand scale"); *see also* 84 FR 32520, 32534 n.152 (July 8, 2019) ("The EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide, or nationwide basis.").
[248] *See*, *e.g*., 80 FR 64510, 64594 (October 23, 2015); 80 FR 64662, 64721 (October 23, 2015).
[249] *See* 84 FR 32520, 32544-46 (July 8, 2019).

action, the Agency's determination of unreasonable adverse impacts has focused on the sector-wide strain that requirements based on 40 percent natural gas co-firing could place on the availability of natural gas. The demand for natural gas, as explained below, is anticipated to be greater than previously projected. Under these circumstances, diverting natural gas for use in natural gas in steam generating boilers could result in an unreasonable impact on the energy system because it reduces the availability of gas for other, more efficient uses, including for electricity generation in combustion turbines.

The analyses the EPA conducted and relied on to assess the 2024 CPS's projected impacts showed only incremental increases in electricity demand: a 13 percent increase between 2000 and 2022, with demand staying relatively flat over the 2007-2022 period. As discussed in section III.C of this preamble, during this period, the share of coal-fired electricity decreased in both absolute and relative terms, while both natural gas-fired net generation and wind and solar net generation increased. Natural gas surpassed the total net generation from coal on an absolute basis in 2016, while renewables surpassed the total net generation from coal on an absolute basis in 2022.[250] The information that the EPA analyzed for purposes of the 2024 CPS indicated that the sector trend of moving away from coal-fired generation was likely to continue, that the share of electricity generation from natural gas-fired sources would likely decline, and that the share of generation from non-emitting technologies would likely continue to increase. One important data point for purposes of the 2024 CPS was that the Agency anticipated that the recent trend of retirements of coal-fired capacity (at an average annual rate of 10 GW from 2015 to 2023) would continue due to the economics of coal-fired generation. At that time, more than half of the operating coal-fired steam generating units had announced retirement or plans to convert to natural gas by 2039.[251] Thus, the EPA predicated the

[250] Document ID No. EPA-HQ-OAR-2023-0072-8920.
[251] 89 FR 39798, 39816-18 (May 9, 2024).

Agency's consideration of energy requirements associated with 40 percent natural gas co-firing in the 2024 CPS on an assumption of a continued and significant decline in the number of coal-fired EGUs.

In contrast, updated information and analysis of power sector trends indicate a significantly different landscape moving forward. In particular, as outlined in section III.C of this preamble, the projections of electricity markets over the coming decades indicate higher electricity demand due to a number of factors. Recent analyses further predict that this higher electricity demand will, in turn, result in higher utilization of coal and gas fired resources[252] than projected under the 2024 analysis underpinning the 2024 CPS.[253] The EPA's updated baseline projections indicate that coal capacity will level off at 100 GW by 2040, in contrast to the 2024 analysis's prediction of continuing to decline from the current level to 52 GW in 2035 and 42 GW in 2040. Similarly, the updated baseline projections indicate that new NGCC additions would be 155 GW in 2035 and 217 GW by 2040, contrasting earlier projections that total just 26 GW in 2035 and 2040. The EPA's updated baseline modeling in the 2025 analysis also projects significantly higher natural gas consumption, even absent the 2024 CPS requirements, with Henry Hub gas prices projected at 18 percent higher by 2030 and 52 percent higher by 2035.

These significant changes in the power sector complement the EPA's reevaluation of the demands natural gas co-firing puts on both individual coal-fired steam generating units and the energy system more broadly, informing the EPA's analysis and determination here. While coal-fired steam generating units may use small amounts of natural gas for startup purposes, relatively few sources use natural gas in proportions that would have been consistent with the requirements for medium-term coal-fired steam generating units in the 2024 CPS. Therefore, the co-firing-based standards would result in

[252] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[253] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA-HQ-OAR-2023-0072-8913.

a significant increase in the demand for natural gas. The 2024 CPS failed to adequately address the impacts of this increase, even before the updated projections of coal capacity and natural gas demand that are now available.

Based on the EPA's reexamination of the facts and conclusions in the 2024 CPS and the analysis supporting this rulemaking, the Agency now finds that 40 percent natural gas co-firing is not the BSER because of the potential for unreasonable adverse impacts related to energy requirements.[254] The EPA's two reasons for this determination—diverting the volume of natural gas needed to support 40 percent co-firing from other uses in the energy system could have significant impacts and natural gas is more efficiently used in natural gas-fired combustion turbines—are described in further detail below. The EPA is determining that the collective effect of these two phenomena could result in unreasonable adverse impacts on the energy system by forcing natural gas, the availability of which is anticipated to become more constrained, to be used in a relatively inefficient manner. The EPA has also balanced these energy impacts against the relatively small amount of CO_2 reductions available from 40 percent natural gas co-firing (16 percent) and the other relevant considerations under CAA section 111(a)(1) (*i.e.*, cost and nonair quality health and environmental impacts) in determining that such co-firing could not be the BSER for medium-term coal-fired steam generating units.

i. 2024 CPS Requirements Reduce the Availability of Natural Gas for Other Purposes

The EPA now finds that the potentially large demand for natural gas associated with 40 percent co-firing in coal-fired steam boilers is unreasonable and could produce a significant adverse consequence related to energy requirements. As explained in the June 2025 NPRM, the EPA believes that coal-fired steam generating unit capacity and generation will now continue to comprise a substantial portion of the nation's electricity

[254] For details on the analysis, see memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).

supply.[255] A number of coal-fired steam generating units are delaying or canceling scheduled retirements in light of increasing electricity demand, the changes in tax incentives for various types of electricity-generating resources in the OBBBA, and Administration actions to support the continued operation of coal-fired capacity.[256] [257] Furthermore, the EPA's modeling projections show a substantial capacity of coal-fired steam generating units operating past 2032.[258] The EPA's updated modeling estimates that 100 GW coal capacity will be operational in the 2035 model run year,[259] whereas the EPA projected 52 GW of coal capacity would exist by 2035 in the 2024 CPS analysis.[260] While it is the case that not all 100 GW would necessarily be subject to the 40 percent co-firing based standard, it is very likely that the amount of capacity that would be so subject is significantly higher than the EPA projected in the 2024 CPS. Because much more coal capacity is anticipated to remain operational than was previously projected in the 2024 CPS modeling (almost twice as much in 2035), it is reasonable to expect that more units could be subject to a standard of performance based on 40 percent co-firing with natural gas. Thus, the total volume of natural gas that sources would need to implement co-firing could be both substantial and greater than previously believed.

More specifically, using the latest available data from the EIA, the U.S. electric sector comprised approximately 174 GW of coal-fired EGUs in 2024, which collectively consumed approximately 6.98 quadrillion Btus of energy. According to operation

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[255] 90 FR 25752, 25772, 25774 (June 17, 2025).
[256] D. Proctor, *U.S. Coal Plants Get Reprieve as Market and Policies Change*, Power (February 6, 2025). Available at: https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change/.
[257] *See, e.g.*, U.S. Department of Energy, 2026 DOE 202(c) Orders. Available at: https://www.energy.gov/ceser/2026-doe-202c-orders.
[258] Under the CPS, coal-fired steam generating units operating past 2032 and choosing to permanently cease operation before January 1, 2039, would have had a standard of performance based on 40 percent natural gas co-firing.
[259] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[260] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA-HQ-OAR-2023-0072-8913. Table 3-14.

planning data reported to the EIA, 146 GW of this 174 GW coal capacity in the U.S. electric sector are expected to remain in service through 2032.[261] If these 146 GW of units maintained their 2024 utilization levels and co-fired 40 percent natural gas, they would draw more than 2.3 quadrillion Btus of natural gas. For context, the entire U.S. electric sector consumed approximately 13.9 quadrillion Btus of natural gas in 2024 (*i.e.*, implementing the co-firing standard would require an increase of 17 percent of 2024's total gas consumption in the U.S. electric sector).

As noted above, there are many critical demands for natural gas other than for electricity generation, including for industrial uses, residential use, and as a transportation fuel. According to the EIA, total demand for all uses of natural gas was approximately 33 quadrillion Btus in 2024. Furthermore, the EIA projects that the demand for natural gas, driven by domestic consumption and liquefied natural gas exports, will grow both in the near term[262] as well as in the long term.[263] EIA forecasts record high industrial and power sector natural gas consumption by 2027[264] [265] and projects a 30 percent increase in LNG exports by 2027 as five new LNG export projects begin operation.[266] This increasing demand stresses supply, resulting in an increase of projected costs of natural gas. Henry

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[261] The survey Form EIA-860 collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants, including scheduled retirements. U.S. EIA. Form 860 data. Available at: https://www.eia.gov/electricity/data/eia860/.
[262] U.S. Energy Information Administration. EIA expects higher wholesale U.S. natural gas prices as demand increases. Available at: https://www.eia.gov/todayinenergy/detail.php?id=64344.
[263] U.S. Energy Information Administration, Annual Energy Outlook 2025. Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2025&cases=ref2025&sourcekey=0.
[264] U.S. Energy Information Administration. U.S. industrial natural gas consumption expected to hit records in 2026 and 2027. Available at: https://www.eia.gov/todayinenergy/detail.php?id=67686
[265] U.S. Energy Information Administration. Natural gas for power generation flat this summer, record high expected in 2027. Available at: https://www.eia.gov/todayinenergy/detail.php?id=67725
[266] U.S. Energy Information Administration. U.S. natural gas exports to grow nearly 30% by 2027 as LNG facilities ramp up. Available at: https://www.eia.gov/todayinenergy/detail.php?id=67484

Hub gas prices in 2024 dollar-years are projected to rise to $4.12/MMBtu by 2030 and $5.26/MMBtu by 2035.[267] In most model run years, EPA's analysis indicates that the cost of natural gas would be higher with the 2024 CPS in place as compared to the scenario absent the requirements of 2024 CPS.[268] Also, updated EPA projections show substantial increases in natural gas combustion turbine generation when compared to prior EPA projections conducted for the 2024 CPS.[269] Using a large volume of natural gas in coal-fired steam generating units when there are already increasing demands on the natural gas supply (from, among other things, higher domestic demand, including due to increased combustion turbine buildout, and greater liquefied natural gas exports) further exacerbates the potential for adverse energy impacts, as evidenced by the natural gas price increases associated with the 2024 CPS requirements. Therefore, the EPA finds that diverting the volume of natural gas necessary to support 40 percent natural gas co-firing from other uses is unreasonable because it could result in a significant adverse impact on the energy system, such that 40 percent natural gas co-firing is not the BSER.

Comments: Some commenters stated that using large quantities of natural gas to fuel steam generating units is extraordinarily wasteful at a societal level. A commenter also argued that the adverse impacts on the energy system are especially unreasonable when compared to the relatively small CO_2 reductions—16 percent—that are available from 40 percent natural gas co-firing.

Other commenters expressed concern that the EPA's objections to the 40-percent co-firing standard based on gas supply were unsupported. Commenters asserted that the EPA lacked data in the June 2025 NPRM to sustain the argument that there is insufficient natural gas supply to support the 40 percent co-firing standard.

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[267] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[268] *Id.*
[269] *Id.*

EPA Response: The EPA agrees with commenters who stated that the impacts of 40 percent natural gas co-firing on the energy system are unreasonable, especially given the relatively small amount of CO_2 reductions available. The Agency also notes that the Agency has broad discretion in weighing the statutory considerations under CAA section 111(a)(1) to determine the BSER.[270] The rationale included in the June 2025 NPRM and further corroborated by the arguments and data included in this final rule justifies the EPA's finding that 40 percent natural gas co-firing would have adverse consequences for the energy system: the co-firing standard could strain the supply of natural gas and reduce its availability for other purposes. Although several commenters cited projected natural gas use and supply figures from the 2024 CPS to support arguments that ample gas would be available for co-firing, such comments do not consider the changed circumstances of the energy sector. The EPA cited these changed circumstances in the June 2025 NPRM and, in this final rule, is adding further information that has become available since the June 2025 NPRM's publication in Spring 2025. As discussed in this preamble, the EPA's updated analysis shows that the total volume of natural gas that affected sources would require to implement the 2024 CPS's co-firing standard is 17 percent of total power sector gas consumption in 2024. This increase is over 20 percent higher than the percent increase estimated under the 2024 analysis using the same approach (*i.e.*, assuming all units active in 2032 co-fire 40 percent natural gas and maintain 2024 utilization levels). This substantial increase in natural gas demand would place upward pressure on natural gas prices.

Moreover, the increase in natural gas demand from co-firing units would now be occurring in the context of significantly higher natural gas prices. The EPA's updated analysis projects that natural gas prices will increase significantly more than the Agency

[270] *See Lignite Energy Council*, 198 F.3d at 933 ("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.").

predicted in its the 2024 analysis of the final 2024 CPS (50 percent higher in 2035 than what was projected under the 2024 analysis), meaning that the impact of the 2024 CPS on the price of natural gas would be greater. The updated analysis projects that, in a scenario with the 2024 CPS remaining in place, the Henry Hub price of gas would increase nine percent in 2035,[271] while the 2024 analysis projected that the Henry Hub price of gas would have increased only three percent as a result of the 2024 CPS in the same year.[272] In sum, the anticipated constraints on natural gas availability combined with substantial increases in natural gas demand mean that diverting a large volume of natural gas to 40 percent natural gas co-firing in coal-fired steam generating units would further exacerbate the already-strained natural gas market.

ii. Inefficiency of 40 Percent Natural Gas Co-firing

The EPA is further concluding that the energy requirements associated with 40 percent natural gas co-firing in a steam generating EGU are unreasonable because such co-firing would be an inefficient use of the comparatively constrained (relative to previous assumptions) availability of natural gas, particularly compared to use in a combustion turbine. This is a relevant consideration because the two types of units provide the same product—electricity—and because they are being covered by a single regulatory regime. [273] The EPA therefore believes that it should attempt to optimize the use of natural gas amongst the affected sources. Applying 40 percent natural gas co-firing would result in a decrease in boiler efficiency by approximately two percent (to a total boiler efficiency of less than 40 percent) due to the higher hydrogen content of natural gas relative to coal. In the 2024 CPS, the EPA argued that this decline in efficiency could be partially offset by decreases in auxiliary power demand related to coal handling and

[271] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[272] Docket ID No. EPA-HQ-OAR-2023-0072, Table 3-12 in the 2024 RIA.
[273] *See* 40 CFR part 60, subparts TTTT and TTTTa.

emissions controls but acknowledged that uncertainty remained about whether this offset would be true in all circumstances.[274] In the EPA's unit-level cost analysis for the 2024 CPS, the Agency assumed a two percent decrease in boiler efficiency would result in one percent overall heat rate penalty for the unit.[275] Thus, for a theoretical coal-fired steam generating unit with a heat rate of 10,000 British thermal units per kilowatt-hour (Btu/kWh), the EPA estimates that the heat rate increases when co-firing to 10,100 Btu/kWh.

Comparatively, the use of large amounts of natural gas for combustion in combined cycle EGUs is more efficient. New natural gas-fired combined cycle EGUs generally have an operating efficiency of greater than 50 percent. If the natural gas that would otherwise be used for co-firing in a steam generating EGU were instead used in a combined cycle unit with a heat rate of 6,700 Btu/kWh, the combined effective heat rate of the coal-fired EGU and gas-fired combined cycle unit would be approximately 8,400 Btu/kWh, which is substantially less than the coal-fired steam generating unit with 40 percent natural gas co-firing. In addition, effective combined heat rates would be lower if the natural gas were used in a simple cycle combustion turbine EGU.[276] As described in section IV.A.2.b.i of this preamble, the availability of natural gas is projected to be relatively constrained due to a combination of increases in domestic demand and increases in liquefied natural gas exports. Given these circumstances, the EPA believes it is reasonable to consider the relative efficiency of natural gas use amongst regulated sources when determining BSER. When looking at the affected source category as a whole, the EPA finds that impacts on the energy system of 40 percent natural gas co-firing are unreasonable because it is significantly more efficient to use natural gas to

[274] 89 FR 39798, 39895 (May 9, 2024).
[275] See spreadsheet entitled *Unit-Level Cost and Reduction Estimates for Natural Gas Co-firing Final Rule* attached to Document ID No. EPA-HQ-OAR-2023-0072-9095.
[276] For a representative combustion turbine with a heat rate of 8,700 Btu/kWh, the combined effective heat rate would be approximately 9,500 Btu/kWh.

generate electricity in a combustion turbine, rather than co-firing natural gas in a steam generating boiler.

Comments: Some commenters supported the EPA's proposed determination that the Agency can or must consider the relative efficiency of co-firing natural gas in a coal-fired steam generating unit versus in a combustion turbine. One commenter stated that co-firing natural gas in a boiler is less efficient than burning natural gas in either a combined cycle system or a simple cycle turbine. Another commenter noted that although choosing to co-fire may be reasonable for individual units due to source-specific circumstances, co-firing is not a reasonable practice on a fleetwide basis.

Other commenters refuted the basis of comparison between heat rates of natural gas co-firing units and NGCC due to the technological differences between an NGCC and a steam unit. Some commenters questioned the relevance of this comparison and asserted that the EPA should consider whether natural gas co-firing reduces emissions from the affected units, not whether a different type of unit can use natural gas more efficiently.

EPA Response: The EPA believes the relative efficiency of steam generating boilers and combustion turbines is relevant because the energy requirements factor of CAA section 111(a)(1) requires the Agency to consider adverse impacts on the energy system.[277] The interplay between different potential uses of a limited fuel to generate electricity is pertinent to this inquiry. Moreover, the EPA believes this is a relevant consideration because coal-fired steam generating units and NGCC units were addressed as part of a common regulatory framework under the 2024 CPS.[278] Thus, the Agency's regulation should acknowledge the competing uses of natural gas by the affected sources. Directing natural gas to be used in a less efficient manner, *i.e.*, in a steam generating

[277] *See* preamble sections II.C.3 and IV.A.2.b for discussion of the EPA's interpretation and application of CAA section 111(a)(1)'s "energy requirements" factor.
[278] *See* 40 CFR part 60, subparts TTTT and TTTTa.

boiler, is not a reasonable use of this resource. This is especially the case when the availability of natural gas is anticipated to be relatively constrained due to multiple competing uses, both within and beyond electricity generation. Furthermore, the EPA has considered the decreased efficiency of a coal unit co-firing 40 percent natural gas relative to the CO_2 reductions available from such co-firing and has determined that the adverse impacts are not reasonable given reductions in emission rate (*e.g.*, lb CO_2/MWh-gross) of only 16 percent.

c. Infrastructure

Finally, the EPA is finalizing the determination that a degree of emission limitation based on 40 percent natural gas co-firing is not achievable because it is unlikely the necessary pipeline infrastructure can be deployed by the compliance date of January 1, 2030. In the 2024 CPS, the EPA estimated the maximum aggregate amount of pipeline capacity at nearly 14.7 billion cubic feet per day for implementing 40 percent natural gas co-firing, which would require approximately 3,500 miles of pipeline.[279] The 2024 CPS further assumed that sources could obtain the permits necessary to construct these pipelines in one year and that the actual construction would require one year or less.[280] While the timelines in the 2024 CPS were based on average permitting, approval, and construction timeframes,[281] the EPA now believes that projects facing reasonably foreseeable adverse conditions could take up to five years for approval and construction.[282]

Further, the EPA now projects that much more coal-fired capacity will remain in operation than previously anticipated, meaning that more natural gas pipeline projects

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[279] 89 FR 39798, 39893 (May 9, 2024).
[280] *Id.* at 39893 n.682.
[281] *Id.* at 39893.
[282] *Documentation for the Lateral Cost Estimation* (2024), *ICF International*, p. 42. Attachment to *Greenhouse Gas Mitigation Measures for Steam Generating Units*. Document ID No. EPA-HQ-OAR-2023-0072-9095.

would have to be undertaken to support 40 percent natural gas co-firing at a nationwide level.[283] This increase would strain existing permitting, planning, and implementation resources and make completion of these projects by the January 1, 2030, compliance date less likely. Furthermore, the involvement of external parties in deploying such a large amount of infrastructure would necessarily include its own complications and delays. Additionally, the EPA did not consider that the large number of these projects, or that the new pipelines necessary to support co-firing, would be in addition to pipeline projects necessary to meet the increasing demand for natural gas for other purposes (*e.g.*, liquified natural gas exports and other domestic uses like powering AI). Specifically, updated EPA power sector modeling that incorporates higher demand and the impacts of the OBBBA estimates 100 GW installed coal capacity by 2035,[284] almost twice as much as projected in the final 2024 CPS analysis.[285] This would require an estimated 90 percent more gas by volume to meet the 40 percent co-firing standard. By that same year, modeling projections estimate an overall gas demand of 16.4 trillion cubic feet with an average delivered price of $4.92/MMBtu.[286] Under the earlier analysis, the lower demand environment and the impact of the IRA resulted in falling natural gas consumption over time in the power sector. The updated analysis, driven by the current higher demand environment and the impacts of the OBBBA, projects increasing natural gas consumption over the forecast period. As a result, the updated forecast projects total gas consumption in 2035 will be 77 percent higher as compared to the forecast used for the 2024 CPS.

The EPA now believes that these factors make it unlikely for the necessary additional pipeline infrastructure for 40 percent natural gas co-firing to be deployed by

[283] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA-HQ-OAR-2025-0124).
[284] *Id*.
[285] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA-HQ-OAR-2023-0072-8913. Table 3-14.
[286] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Document ID No. EPA-HQ-OAR-2025-0124).

the January 1, 2030, compliance date. Therefore, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for medium-term coal-fired steam generating EGUs is not achievable.

Comments: Commenters supporting the EPA's determination generally expressed concern with the feasibility of the January 1, 2030, compliance deadline for 40 percent natural gas co-firing in the 2024 CPS, stating that this deadline was not achievable because of the required time for permitting and construction of natural gas pipelines, particularly interstate pipelines. These commenters explained that the EPA's assumptions in the 2024 CPS about the amount of time it takes to design, permit, and construct natural gas lateral pipelines were unrealistically optimistic. Other commenters, however, supported the compliance deadline for the 40 percent natural gas co-firing based on the examination of national averages in 2024.

EPA Response: The EPA agrees with the former and disagrees with the latter commenters. As detailed in this section of the preamble, the EPA now believes that projects facing reasonably foreseeable adverse conditions could require up to five years for approval and construction, particularly in light of increased demand for natural gas that could further extend approval and construction periods.[287]

As noted by supportive commenters, a longer approval and construction timeline for pipelines would be more appropriate based on the longest project approval timeline for any project reviewed (Carty Lateral Project) combined with the longest construction timeline for any project reviewed (Coastal Bend Header), which totals to 49 days short of five years. Such an implementation timeframe would, in contrast to the timeframe the EPA promulgated in the 2024 CPS, ensure that regulated entities facing reasonably foreseeable delays in both project approval and construction could still timely comply

[287] *Documentation for the Lateral Cost Estimation* (2024), *ICF International*, p. 42. Attachment to *Greenhouse Gas Mitigation Measures for Steam Generating Units*. Document ID No. EPA-HQ-OAR-2023-0072-9095.

with the applicable requirements. Furthermore, assuming the longer timeline is reasonable because the increase in the use of natural gas for other purposes will likely necessitate additional pipeline buildout for these purposes, which will further delay pipeline approval and construction time for the electric power sector.

The EPA now believes that these factors make deployment of the necessary additional pipeline infrastructure for 40 percent natural gas co-firing by the January 1, 2030, compliance date unlikely. Therefore, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for existing medium-term coal-fired steam generating EGUs is not achievable.

d. Conclusion

In summary, the EPA is finalizing the repeal of the requirements of the emission guidelines pertaining to medium-term coal-fired steam generating units because natural gas co-firing in a coal-fired steam generating EGU is impermissible generation shifting, the energy requirements associated with 40 percent natural gas co-firing are unreasonable, and the degree of emission limitation specified in the 2024 CPS is not achievable. As discussed in this section of the preamble, the EPA is addressing only 40 percent natural gas co-firing and implementation by January 1, 2030, because those were the requirements under the 2024 CPS. This action does not address any potential alternative BSERs or implementation timeframes such as lower rates of co-firing or a later implementation date. The EPA considered whether to analyze and promulgate potential alternatives and determined it is not necessary to do so under the circumstances presented here.

3. Requirements for Existing Natural Gas- and Oil-Fired Steam Generating Units

The EPA is finalizing the repeal of the requirements of the emission guidelines pertaining to natural gas- and oil-fired steam generating units. In the 2024 CPS, the EPA finalized routine methods of operation and maintenance as the BSER for intermediate load and base load natural gas- and oil-fired steam generating units and uniform fuels as the BSER for low load natural gas- and oil-fired steam generating units. Because those BSERs were consistent with the current operations at most sources (*i.e.*, business-as-usual), there was no associated additional cost. In addition, those BSERs resulted in a degree of emission limitation that would have led to few, if any, emission reductions for any of the units. The EPA did not propose to repeal the BSER determinations and degrees of emission limitation for those sources. However, the EPA proposed to repeal the requirements in the emission guidelines for natural gas- and oil-fired steam generating units because requiring States to develop, submit, and implement state plans solely for natural gas- and oil-fires steam generating units would be an inefficient use of State resources, as these sources comprise a relatively small part of the source category and regulating them would have little environmental benefit.

Comments: Several commenters supported the EPA's proposal in the June 2025 NPRM to repeal the portions of the emission guidelines applicable to oil- and natural gas-fired steam generating units. These commenters generally agreed that requiring States to develop and submit state plans for these units alone would be an inefficient use of limited State resources that would present an undue administrative burden. Commenters further asserted that, if regulating these sources would have no significant benefit in terms of emission reductions, then such regulation would not be of reasonable cost. Additionally, some commenters explained that there is no need for the EPA to retain the emission guidelines for these units because the BSERs for oil- and natural gas-fired steam generating units are consistent with business-as-usual operation.

Other commenters opposed repealing the emission guidelines for these units for several reasons. Those commenters asserted that CAA section 111(d) requires the EPA to promulgate emission guidelines for existing sources if the Agency has promulgated standards of performance for the corresponding new sources. Commenters argued that standards of performance currently exist for GHG emissions from new oil- and natural gas-fired steam generating units, and that the EPA cannot override the statutory directive to have regulations for existing units based only on the Agency's judgment that state plans would not be prudent. Commenters stated that this is particularly the case because the EPA has not identified any flaw with the BSER determinations or emission guidelines for oil- and natural gas-fired steam generating units. The commenters further asserted that the EPA's justification for repealing the emission guidelines under CAA section 111 (*i.e.*, requiring States to submit plans covering just these units would be "imprudent" and an inefficient use of State resources) is not legally cognizable and that, regardless, the presumptive standards for these units would be straightforward and the EPA has not explained why business-as-usual standards would require expenditure of resources on engineering analyses. Commenters suggested that the 2024 CPS standards cover approximately 200 natural gas-fired steam generating units and 30 oil-fired units, that these units contribute an outsized amount of pollution as compared to electricity generation, and that the emission guidelines provide important protections against increased emissions as these units age. Finally, commenters asserted that it is not, in fact, a significant burden for States to prepare plans to regulate these units and that the EPA has not provided evidence to the contrary. Commenters stated that if a State finds preparing a plan too burdensome or otherwise chooses not to submit a plan, the EPA will issue a federal plan instead.

EPA Response: The EPA acknowledges these comments but continues to believe that it is not a reasonable use of States' resources, nor the Agency's (in the case of a federal plan), to develop and submit plans for oil- and natural gas-fired steam generating units while the Agency is repealing the requirements for all other existing fossil fuel-fired power plants. Natural gas- and oil-fired steam generating units represent a very small portion of the source category from both a generation and an emissions perspective. In

2023, natural gas- and oil-fired steam generating units accounted for 1.2 percent of total electric generation and 3.5 percent of power sector CO_2 emissions in the U.S.[288] The EPA's forecasts of power sector behavior using the Integrated Planning Model in the 2025 Reference Case projects that this share of both generation and emissions in the U.S. will decrease even further over the forecast period.[289]

Although the EPA is not finding that the BSERs or presumptive standards in the 2024 CPS were unreasonable or inappropriate for these sources, the Agency believes that it would be unreasonable to require States to develop state plans solely for these units. Throughout the more than 50-year period that the EPA has promulgated CAA section 111 regulations establishing NSPS for new sources and emissions guidelines for existing sources,[290] the EPA's regulatory approach has been to apply a rule of reason in determining which air pollutants and which source categories to regulate. This approach is consistent with CAA section 307(d)(9)(A), which provides that promulgation of standards of performance under CAA section 111 is subject to the CAA section 307(d)(9)(A) arbitrary and capricious standard for judicial review. *See American Electric Power Co.* v. *Connecticut,* 564 U.S. 410, 424, 427 (2011). For example, in 1977, EPA listed the stationary gas turbine source category,[291] and proposed standards of performances for NOx and SO2 because the source category emitted those pollutants in large quantities and reasonably priced controls for them were available, but did not propose standards for HC or CO because those emissions were "relatively low" when the turbines were operated at peak capacity or PM because those emissions were

[288] Based on eGRID2023 data. Available at: https://www.epa.gov/egrid/detailed-data.
[289] EPA 2025 Reference Case. Available at: https://www.epa.gov/power-sector-modeling.
[290] The EPA first listed source categories and promulgated standards of performance for them in 1971, 36 FR 5931 (March 31, 1971) (listing initial source categories); 36 FR 24876 (December 23, 1971) (promulgating initial standards of performance).
[291] 42 FR 53657 (October 3, 1977).

"minimal."[292] In 1979, EPA finalized the standards for NOx and SO_2.[293] EPA has similarly applied a rule of reason in determining whether to regulate particular source categories. For example, after enactment in the 1977 CAA Amendments of CAA section 111(f), which directed EPA to list source categories of major stationary sources and promulgate NSPS for them on a specified schedule, EPA promulgated a list of source categories and assigned each one a priority for action. However, EPA noted that "if further study indicates that an NSPS would have little or no effect on emissions, or that an NSPS would be impractical, a source category would be given a lower priority or removed from the list."[294]

In applying a standard of reasonableness here, the EPA anticipates that the business-as-usual BSERs and presumptive standards finalized in the 2024 CPS would result in little to no emission reductions, while at the same time the development of state plans involves an expenditure of resources by States and regulated entities, including time and money for developing compliance strategies, conducting public hearings and meaningful engagement, drafting permits or other legal instruments, and getting necessary legislative or other approvals.[295] Therefore, the pragmatic considerations outweigh any potential regulatory benefit: requiring state plans to address only these sources at the same time the Agency is repealing the requirements for all other existing sources, and when the BSERs and presumptive standards of performance in the 2024 CPS would not, in general, have resulted in changes in operations or emissions, would

[292] 42 FR 53782, 53783 (October 3, 1977).
[293] 44 FR 52792 (September 10, 1979). As another example, the EPA promulgated standards for lime manufacturing plants for particulate matter, but not for NOx, CO, or SO2, due to their small amount of emissions or concerns about the available controls. *See* 42 FR 22056, 22507 (May 3, 1977); *Nat'l Lime Ass'n*, 627 F.2d at 426 & n.27.
[294] 44 FR 49223 (August 21, 1979).
[295] The EPA's Information Collection Request analysis for the emission guidelines promulgated in the CPS indicates that developing state plans (and negative declarations) would entail a collective cost to the 48 States subject to the rule of approximately $35 million over three years. *See* Document ID No. EPA-HQ-OAR-2023-0072-8836.

not be reasonable.[296] Thus, the EPA is finalizing the repeal of the requirements of the emission guidelines pertaining to natural gas- and oil-fired steam generating units.

Moreover, as discussed in this section of the preamble, the EPA is simultaneously issuing a supplemental proposal soliciting comment on additional reasons beyond those on which the EPA solicited comment in the primary proposal in the June 2025 NPRM to repeal the legal basis for regulating GHG emissions from fossil fuel-fired power plants under CAA section 111. If finalized as proposed, this subsequent action would abrogate the need to regulate GHG emissions from natural gas- and oil-fired steam generating EGUs entirely. If the EPA does not finalize the determination that the Agency lacks authority to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111 as proposed, the EPA would revisit the need for requirements for natural gas- and oil-fired steam generating EGUs.

4. Conclusion

Because the EPA is finalizing the repeal of the BSER determinations and related requirements for existing long-term and medium-term coal-fired steam generating units and is further finalizing the repeal of the requirements for existing oil- and natural gas-fired steam generating units, the Agency is finalizing repeal of the emission guidelines for steam generating units in 40 CFR part 60, subpart UUUUb, in their entirety.

B. Repeal of the CCS-Based Requirements for Coal-Fired Steam Generating Units Undertaking a Large Modification

In the 2024 CPS, the EPA finalized revisions to the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.*, a modification

[296] One commenter asserted that the presumptive standards of performance, which the EPA determined in the CPS, may not be appropriate given how oil and natural gas-fired steam generating units may operate in the future. Comments of Talen Energy at 16-17, Document ID No. EPA-HQ-OAR-2025-0124-0904. Although the EPA is not repealing the emission guidelines for these sources on the basis of the achievability of the presumptive standards of performance, the Agency does note this concern.

that increases the unit's hourly emission rate by more than 10 percent) to be consistent with the 90 percent CCS requirements for existing coal-fired steam generating units. As discussed in section IV.A.1 of this preamble, the EPA is finalizing the determination that 90 percent CCS is not an adequately demonstrated system of emission reduction and that the cost of 90 percent CCS is not reasonable. For these reasons, the EPA is also finalizing repeal of the CCS-based standards of performance for coal-fired steam generating units undertaking a large modification in 40 CFR part 60, subpart TTTT.

C. Partial Repeal of the 2024 Standards for New Combustion Turbine EGUs

The EPA is finalizing the repeal of the phase 2 CCS-based standards for new base load stationary combustion turbine EGUs in 40 CFR part 60, subpart TTTTa. The EPA's basis for this action is that 90 percent CCS has not been adequately demonstrated, and the costs are not reasonable for new base load combustion turbines. The EPA is finalizing the determination that the CCS-based standards are not achievable as it is unlikely that the infrastructure necessary can be deployed by the January 1, 2032, compliance date. In the June 2025 NPRM, the EPA solicited comment in general on the efficiency-based standards for intermediate load and base load turbines. While the EPA received substantial comments that affected sources may not be able to achieve these standards, the EPA is not addressing these comments at this time.

1. Phase 2 CCS-Based Requirements for New Base Load Combustion Turbines

In the 2024 CPS, the EPA determined the second component of the BSER for new base load combustion turbines to be 90 percent CCS. The EPA determined that 90 percent CCS, including the 90 percent CO_2 capture component, was adequately demonstrated based on extrapolation from the evidence for 90 percent CCS on coal-fired steam generating units and additional examples and planned projects on combustion turbines. The EPA also argued the costs were reasonable and that the other considerations for BSER were satisfied. Based on application of the 90 percent CCS BSER to new base load combustion turbines, the EPA established standards of performance and argued these standards were achievable by the compliance date of January 1, 2032, considering the time necessary to deploy capture equipment, transport, and sequestration.

The EPA proposed to repeal the phase 2 CCS-based requirements for new base load combustion turbines based largely on a reassessment of the record underlying the determinations in the 2024 CPS. The EPA proposed that 90 percent CCS is not the BSER for new base load combustion turbines because it has not been adequately demonstrated and the costs are unreasonable. The EPA further proposed that the standards of performance are not achievable because it is unlikely that the infrastructure (including capture equipment, pipelines for transport, and sequestration sites) for 90 percent CCS for new base load combustion turbines can be deployed by the January 1, 2032, compliance date.

The EPA is finalizing the determination that CCS with 90 percent capture is not the BSER for base load combustion turbine EGUs because it has not been adequately demonstrated and the costs are not reasonable. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is finalizing the determination that the associated standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. Consequently, the EPA is finalizing repeal of the phase 2 standards for base load combustion turbine EGUs.

a. Adequately Demonstrated

For many of the same reasons described in section IV.A.1.a of this preamble for coal-fired steam generating units, CCS with 90 percent capture has not been adequately demonstrated for new combustion turbine EGUs. The 2024 CPS based the 90 percent capture BSER for new base load combustion turbines on the same capture technology as for coal-fired steam generating units.

i. Translation of Experience at Coal-fired EGUs

The 2024 CPS relied on the translation of amine-based capture at coal-fired EGUs as evidence to support the determination that 90 percent capture on new natural gas-fired combustion turbine EGUs has been adequately demonstrated. However, as noted in section IV.A.1.a of this preamble, the determination for coal-fired EGUs in the 2024 CPS relied on an extrapolation that, on review, fails to show 90 percent capture is adequately demonstrated. Consequently, the EPA has re-assessed the evidence and is finalizing the determination that 90 percent capture and, therefore, 90 percent CCS have not been adequately demonstrated for existing coal-fired steam generating units. Therefore, the record for 90 percent capture on existing coal-fired steam generating units also does not show that 90 percent capture, or 90 percent CCS, is adequately demonstrated for new base load combustion turbine EGUs.

Additionally, the 2024 CPS argued that fewer contaminants (particulates, trace metals, sulfur dioxide (SO_2)) in the post-combustion flue gas of natural gas-fired stationary combustion turbines would result in fewer challenges with CO_2 capture than those experienced with capture at coal-fired steam generating units. However, the exhaust gas composition for natural gas-fired combustion turbines is different in other ways than for coal-fired units (*i.e.*, lower CO_2 concentrations and higher oxygen concentrations), which makes CO_2 capture more challenging. Furthermore, combustion turbines can change loads more rapidly and start and stop more frequently than coal-fired steam generating units. These factors could create additional challenges for operating CO_2 capture equipment, and demonstrated capture rates from coal-fired EGUs do not necessarily demonstrate that base load combustion turbines could achieve the same capture rates. For example, the startup of the CO_2 capture system may be slower than the startup of a combined cycle combustion turbine EGU, so that the system would not capture CO_2 emitted during startup. This shows that directly applying the record for CO_2

capture at coal-fired EGUs to the evaluation of CO_2 capture as adequately demonstrated for natural gas-fired combustion turbine EGUs, without accounting for the differences between these types of units, is inappropriate.

ii. Capture Projects on Combustion Turbine EGUs

The examples of CO_2 capture applied directly on combustion turbine EGUs are also insufficient to conclude that 90 percent capture has been adequately demonstrated. Primarily, there have been limited examples of applications of CCS to combustion turbine EGUs, none of which have been at sufficient scale to demonstrate the specified BSER based on a 90 percent total capture efficiency.

In the 2024 CPS, the argument that 90 percent capture was adequately demonstrated at combustion turbine EGUs relied in part on the capture plant at the Bellingham combined cycle turbine.[297] This capture plant was only 40 MWe, which is smaller than most base load combined cycle turbine EGUs that would have potentially been subject to the requirements of that rule, and processed only approximately 10 percent of the maximum flue gas volume. The project began operation in 1991 before shutting down in 2005 after the host combined cycle unit switched to peak shaving operation.[298] Publicly available data for this project is limited, so that the performance cannot be accurately assessed. The EPA otherwise cited pilot studies.[299] However, such short-duration demonstrations may not be subject to the same variations in conditions that occur in commercial operation. Boundary Dam Unit 3 remains the only relevant commercial scale attempt at applying 90 percent CCS on a fossil fuel-fired power plant. Reasonable extrapolation from the experience at Boundary Dam Unit 3 shows that

[297] 89 FR 39925-26 (May 9, 2024)

[298] Fluor. The U.S. Carbon Capture and Storage Market. Available at: https://newsroom.fluor.com/featured-stories/blog-details/2025/The-U-S--Carbon-Capture-and-Storage-Market-Fluors-Role-45Qs-Influence-Challenges-for-New-and-Existing-Technologies-and-Which-Projects-Can-Succeed/default.aspx

[299] 89 FR 39798, 39927 (May 9, 2024).

commercial scale deployments of CO_2 capture solvent technologies on post-combustion flue gas of fossil fuel-fired EGUs will underperform. Similar to coal-fired steam generating units, a capture system on a gas-fired combined cycle unit would achieve far less than 90 percent capture.[300]

The EPA also previously cited planned projects.[301] However, the planned projects are neither operational nor provide measured data. While the equipment for those planned projects may have been designed for 90 or even 95 percent CO_2 capture, simply designing a project for a certain percentage capture does not ensure that the project will achieve that percentage capture in practice. Boundary Dam Unit 3 did not achieve its design percentage capture, as detailed in section IV.A.1.a.i of this preamble. Therefore, because those hypothetical projects have not yet produced any data, they do not mitigate the potential underperformance of CO_2 capture, and, therefore, are not sufficient to show 90 percent CO_2 capture is adequately demonstrated. The EPA also noted the NET Power Cycle (*i.e.*, CO_2 capture based on oxy-combustion) as a potential technology for meeting the standard based on 90 percent capture. However, the technology provider has not operated the technology at scale and a planned project is facing delays.[302] More recently, the technology provider has deprioritized their efforts on oxy-combustion, and acknowledged it requires further development.[303] Similarly, none of the other projects that the EPA cited have yet commenced construction, either on new NGCC units or on retrofits to existing plants.

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[300] Using the same calculation detailed in section IV.A.1.a.i of this preamble, a system could achieve at best 63 to 82 percent capture.

[301] 89 FR 39798, 39927 (May 9, 2024).

[302] Net Power, Press Release: Net Power Reports Fourth Quarter 2024 Results and Provides Business Update (March 10, 2025). Available at: https://ir.netpower.com/resources/press-releases/detail/37/net-power-reports-fourth-quarter-2024-results-and-provides-business-update.

[303] Net Power, Press Release: Net Power Reports Third Quarter 2025 Results and Provides Business Update (November 13, 2025). Available at: https://ir.netpower.com/resources/press-releases/detail/44/net-power-reports-third-quarter-2025-results-and-provides-business-update.

Comments: Many commenters agreed with the EPA's proposed determination that 90 percent CCS is not adequately demonstrated for new base load natural gas-fired combustion turbines. Other commenters asserted that 90 percent capture is adequately demonstrated for those sources. Those commenters largely reiterated arguments made in the 2024 CPS, which the EPA has refuted in the preceding sections of this preamble. Those commenters also cited references to some new projects that were not in the record for the 2024 CPS and asserted those projects supported the conclusion that 90 percent CCS has been adequately demonstrated for new base load combustion turbine EGUs. One of the projects cited by commenters was the Ravenna CCS project in Italy, a small-scale capture project at a gas processing facility. Commenters argued this project supported the determination that 90 percent CCS was adequately demonstrated for new base load combustion turbines. Commenters similarly cite small-scale pilot projects, such as the pilot plant at the Himeji No. 2 gas-fired power plant in Japan (five metric tons per day), testing on NGCC flue gas at Los Medanos Energy Center (Contra Costa County, California) (1 MWe), and testing on NGCC flue gas at Technology Centre Mongstad (Mongstad, Norway) (10 MWe). In addition, some commenters cited other projects that are not operational, including the Net Zero Teeside Power project (United Kingdom).

EPA Response: The EPA disagrees with commenters' assertions as those projects are insufficient, for various reasons, to conclude that 90 percent CCS has been adequately demonstrated for base load natural gas-fired combustion turbine EGUs. The EPA finds the Ravenna project is insufficient to conclude 90 percent is adequately demonstrated. The project at Ravenna uses an amine solvent to capture CO_2 from the flue gas of a small 5 MW simple cycle combustion turbine, which drives a compressor for natural gas transmission. A heat recovery steam generator produces process steam and renewable generation provides electricity for the capture process. The combustion turbine is therefore not subject to the electricity and steam requirements of the capture process. This is distinct from the premise of the BSER in the 2024 CPS, where the EGU is a combined cycle unit and the capture system uses heat and power from the host EGU, such that changes in operation of the host EGU may impact the capture facility. Moreover, the 2024 CPS applied to units greater than 25 MW, at least five times the size of the project at Ravenna. Considering those factors, the system at Ravenna has limited relevance to the capture system at issue in the 2024 CPS and this action. In addition, from startup in August 2024 through February 2025, the reported monthly average capture efficiency of the treated flue gas (when operating) was 91.8 percent with a peak of 96.1 percent. However, while reports claimed that the GHG emissions of the project were minimal, reports did not specify the amount of flue gas treated relative to the amount emitted from the facility and the amount of time the capture facility was operational. Lacking that information, it is impossible to evaluate the total capture efficiency and the performance of the project in practice. Because of the limited relevance of the Ravenna project to the capture system at issue here, and because of the incomplete information on the performance of the capture system, the EPA concludes that the experience at Ravenna is insufficient to conclude that 90 percent CCS is adequately demonstrated.

Furthermore, for the reasons detailed in section IV.A.1.a.i of this preamble, the EPA reasonably expects that a new capture system would underperform to a similar degree as Boundary Dam Unit 3. Such short term and small-scale projects cited by the commenters are insufficient to mitigate that potential underperformance, and therefore insufficient to show 90 percent capture is adequately demonstrated. Additionally, projects cited by the commenters that are not yet operational have not provided any data on capture performance and are therefore insufficient to that 90 percent capture is adequately demonstrated.

Considering these factors, the EPA is finalizing the determination that CCS with 90 percent capture has not been adequately demonstrated for new base load combustion turbine EGUs.

b. Cost

The EPA has re-evaluated the assumptions underlying the cost analysis of 90 percent CCS on new base load combustion turbines and is finalizing the determination that the costs are not reasonable.

i. Smaller Combustion Turbines

As part of the phase 1 BSER analysis for combustion turbines, the EPA reviewed the performance and costs of efficient generation for combustion turbines with base load ratings ranging from 490 to 6,100 MMBtu/h. Based on the phase 1 BSER analysis, the EPA established higher emission standards for base load turbines with base load ratings of less than 2,000 MMBtu/h. However, when evaluating the phase 2 BSER based on the use of CCS, the EPA evaluated the reasonableness of the cost based only on combustion turbines with base load ratings of 4,600 and 6,100 MMBtu/h.[304] The costs of the capture equipment and the costs to transport and store the captured CO_2 increase on a $/ton basis for smaller base load combustion turbines. The costs of control on a $/MWh and $/ton basis for the smaller model combustion turbine facilities used in the phase 1 analysis are approximately double the highest costs that the EPA reported in the technical support document. Specifically, the estimated compliance costs for the primary case for the 490 and 1,000 MMBtu/h model combined cycle plants are $73/MWh and $200/ton and $55/MWh and $140/ton, respectively, which are significantly higher than the highest

[304] The technical support document entitled *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* included estimated costs for combined cycle turbines with base load ratings of 2,400 and 3,400 MMBtu/h in figures 11 through 13. The costs for the primary case are $29/MWh and $95/ton and $22/MWh and $75/ton respectively—approximately 50 percent higher than the costs presented in the CPS. Document ID No. EPA-HQ-OAR-2023-0072-9099.

costs presented in the 2024 CPS—$19/MWh and $57/ton.[305] Consequently, the EPA now finds that, in the 2024 CPS, the Agency did not establish that the cost of 90 percent CCS is reasonable for smaller base load combustion turbines.

ii. Operating-Availability, Capacity Factor, and Other Assumptions

Even without factoring in the previously cited omissions, the primary costs of 90 percent CCS for combustion turbines were a best-case scenario.[306] As described in section IV.A.1 of this preamble, the EPA assumed in the 2024 CPS that capture equipment has 100 percent operating-availability. Reducing the operating-availability of the capture equipment to 75 percent reduces the CO_2 emission reductions and increases the cost by approximately $2/MWh and $18/ton compared to the estimated costs presented in the 2024 CPS.[307] While CCS may achieve potential CO_2 emission reductions, these costs exceed the thresholds that the EPA cited as reasonable in previous Agency rulemakings.

In addition, when conducting the BSER analysis, the EPA assumed that the long-term capacity factors of new combined cycle turbines would be the same as historical long-term capacity factors with and without 90 percent CCS (51 percent capacity factor).[308] In the primary policy case, the EPA compared the costs and emissions impacts

[305] See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at New and Reconstructed Natural Gas-Fired Combustion Turbine Electric Generating Units* in the docket for this rulemaking (Document ID No. EPA-HQ-OAR-2025-0124).

[306] The EPA discussed multiple advances that could lower the costs of a BSER based on the use of CCS, but currently none of these technologies are commercially available.

[307] See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at New and Reconstructed Natural Gas-Fired Combustion Turbine Electric Generating Units* in the docket for this rulemaking (Document ID No. EPA-HQ-OAR-2025-0124).

[308] Based on data submitted to the Clean Air Markets Program, the median annual capacity factor of combined cycle turbines begins at a high of 68 percent and steadily declines to 34 percent in year 30. The median 30-year capacity factor is 51 percent. To avoid impacting the costs due to changes in the overall capacity factors with the base case, the EPA kept the overall 30-year capacity factor at the historical average of 51 percent.

assuming a new combined cycle turbine with CCS that operates at an 80 percent capacity factor for the first 12 years and a 31 percent capacity factor for the next 18 years.[309] The EPA compared the levelized cost of electricity of this model facility to a combined cycle without CCS that operates at a 62 percent capacity factor for the first 12 years, a 47 percent capacity factor for the next 13 years, and a 37 percent capacity factor for the final five years.[310] However, the capacity factor assumptions in the 2024 CPS do not account for differences in incremental generating cost affecting dispatch. Based on cost information from NETL and EIA's Annual Energy Outlook, and assuming the full value of the IRC section 45Q tax credit, the incremental generating costs of combined cycle turbines with carbon capture are generally higher than those of nuclear EGUs but lower than those of coal-fired EGUs without carbon capture.[311] While the capacity factors of nuclear EGUs are higher (approximately 90 percent) than the 80 percent used by the EPA, the recent capacity factors of coal-fired EGUs are much lower (approximately 40 percent). While these provide an upper and lower bound of what capacity factors could be from a combined cycle turbine with CCS while the tax credit is available, the EPA selected the upper end of the range without conducting a dispatch analysis. Furthermore, even when counting the full value of the IRC section 45Q tax credit as a reduction, the

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[309] The EPA selected 80 percent to account for the lower variable operating costs when the 45Q tax credits are available. The capacity factor during the final 18 years was adjusted to maintain a 30-year average capacity factor of 51 percent.

[310] The 62/47/37 operating scenario is based on the averaged reported median capacity factors for combined cycle turbines during the three periods of operation—62 percent during years 1 to 12, 47 percent during years 13 to 25, and 37 percent during years 26 to 30.

[311] T. Schmitt, S. Leptinsky, M. Turner, A. Zoelle, M. Woods, T. Shultz, and R. James *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4a*, U.S. DOE. National Energy Technology Laboratory (NETL). (October 14, 2022). Available at: https://netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9; Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies. U.S. DOE. U.S. Energy Information Administration (EIA). (January 2024). Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

estimated incremental generating costs of the 490 MMBtu/h combined cycle turbine with carbon capture are higher than the incremental generating costs of the model plant without CCS. Generally, combined cycle facilities without CCS that have recently commenced operation have not maintained capacity factors of 80 percent, this calls the capacity factor assumptions into question for smaller combined cycle facilities with CCS.[312] Additionally, during periods when the IRC section 45Q tax credit is not available after the 12-year period of the credit has expired, it is unlikely that combined cycle turbines with carbon capture would operate at the 31 percent capacity factor used in the 2024 CPS costing analysis. The incremental generating costs of all the model combined cycle turbines with carbon capture exceed the incremental generating costs of simple cycle turbines. Simple cycle turbines generally operate at capacity factors of less than 10 percent. A dispatch modeling analysis would likely result in lower capacity factors and higher costs, which does not support the costs of 90 percent CCS as reasonable.

Further, the EPA only conducted the BSER analysis using capacity factors for the average combined cycle facility. The average combined cycle facility has a 30-year capacity factor of 51 percent. On average, new combined cycle facilities operate at a 65 percent capacity factor that steadily decreases to less than 40 percent by year 30. However, a combustion turbine that ever exceeds the base load threshold (40 percent in the 2024 CPS) for a single 12-operating month period would, effectively, have to install 90 percent CCS to comply with the base load emissions standard. Therefore, while the EPA was correct in using the average capacity factor to determine if the costs of 90 percent CCS are reasonable, the maximum 12-calendar month capacity factor is the appropriate value for subcategorization purposes. A base load subcategorization threshold of 65 percent would subject the average combined cycle turbine to the CCS-based BSER.

[312] Based on information submitted to the EPA's Clean Air Markets Program Data, the 2025 average annual capacity factor of combined cycle turbines that commenced operation between 2020 and 2024 is 65 percent.

However, the EPA set a base load subcategorization capacity factor threshold of 40 percent. In doing this, the Agency subjects combustion turbines with lifetime capacity factors of less than 51 percent to a 90 percent CCS-based BSER. However, in the 2024 CPS, the EPA did not analyze whether 90 percent CCS qualifies as the BSER at lower capacity factors. For example, the 12-operating month capacity factor will vary over the life of the facility, even assuming a combined cycle facility operates at a relatively constant capacity over the entire 30-year life. If the absolute difference between the maximum 12-operating month and 30-year average capacity factors is five percent, the EPA should have determined whether CCS is the BSER for a combined cycle operating at a 30-year capacity factor of 35 percent. At a capacity factor of 35 percent, the costs of CCS are clearly not reasonable ($36/MWh and $110/ton), and costs are even higher for smaller units ($56/MWh and $170/ton).[313] In addition, if the EPA accounted for both the declining capacity factors as combustion turbines age and the 12-operating month variability, the 30-year capacity factor of a combined cycle turbine with a maximum 12-operating month capacity factor of 40 percent would be less than 35 percent, which calls into question whether the cost of 90 percent CCS at a 40 percent subcategorization threshold is reasonable since the costs are three times higher than the cost ($18.5/MWh) the EPA previously determined to be reasonable.[314]

When conducting the BSER analysis, the EPA failed to account for additional factors that would increase the costs of CCS. First, the Agency did not account for lost revenue due to lower capacity payments that result from the lower net output of

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[313] The costs for the combustion turbine model plant with a 6,100 MMBtu/h base load rating is $36/MWh ($110/ton) at a 35 percent capacity factor. The costs for the combustion turbine model plant with a 2,400 MMBtu/h base load rating is $56/MWh ($170/ton) at a 35 percent capacity factor.

[314] Assuming an initial capacity factor of 40 percent that declines to 22 percent at year 30 results in an overall capacity factor of 30 percent. Costs are similar to the constant 35 percent capacity factor case.

combined cycle facilities with CCS relative to combined cycle facilities without CCS.[315] Assuming a capacity payment of $65/kW, a 1x1 F-class combined cycle facility would lose almost $3 million per year in capacity payments, and a 1x1 H-class combined cycle facility would lose almost $4 million per year in capacity payments.[316]

iii. The IRC Section 45Q Tax Credit

As noted above in connection with the costs of CCS for existing coal-fired plants, the 2024 CPS accounted for the IRC section 45Q tax credits by reducing the direct costs to the source for every ton of CO_2 captured. However, the EPA no longer believes that counting the IRC section 45Q tax credit as a reduction in determining BSER is appropriate, as discussed in section IV.A.1.b of this preamble. Rather, the tax credit shifts the costs of CCS to taxpayers, and in the 2024 CPS, the EPA failed to account for those costs. Removing the tax credit as a reduction in the costs for the 2024 CPS 90 percent CCS case increases the costs for combustion turbines with base load ratings of 4,600 and 6,100 MMBtu/h to $37/MWh ($110/ton) and $32/MWh ($100/ton), respectively. Even using the 2024 CPS primary model plants, the costs of 90 percent CCS for base load stationary combustion turbines are clearly unreasonable.[317]

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[315] The capacity markets pay owners of generating units based on the ability to provide firm power regardless of if any electricity is actually delivered to the electric grid.

[316] The EPA notes that when the Agency finalized subpart TTTTa, only the most efficient combustion turbines with base load ratings of greater than 850 MMBtu/h would have required the installation of a selective catalytic reduction (SCR) to comply with the criteria pollutant NSPS (subpart KKKK). Less efficient simple cycle turbines could comply with the criteria pollutant NSPS using advanced combustion controls. Since subpart TTTTa is based on the use of the most efficient combustion turbines, the EPA should have accounted for the costs of SCR as part of the BSER evaluation. While the new criteria pollutant NSPS (subpart KKKKa) does not require the use of SCR for any non-base load combustion turbines as a procedural matter, the EPA should have addressed the issue in the final subpart TTTTa rulemaking.

[317] The costs for the 1x1 F-class and 1x1 H-class are $47/MWh ($140/ton) and $39/MWh ($120/ton) respectively.

c. Infrastructure

Consistent with the arguments presented in section IV.A.1.c of this preamble regarding CCS infrastructure for existing coal-fired steam generating units, the necessary infrastructure to meet the requirements for the phase 2 CCS-based requirements for base load combustion turbines cannot likely be deployed by the January 1, 2032, compliance date. While new combustion turbines do not have the additional timeline requirement of state plan development, the timeline in the 2024 CPS for the design, permitting, and installation of capture equipment, pipelines, and sequestration for new combustion turbines assumes an unrealistic best-case scenario. Furthermore, pipeline and sequestration infrastructure remain limited. In the 2024 CPS, the EPA argued that new combustion turbines could site preferentially near potential storage sites. However, the EPA did not consider the availability of sufficient quantities of natural gas or the availability of sufficient transmission capacity (*i.e.*, to transmit power to end users) for new base load combustion turbines specifically located near potential storage sites.[318] In addition, the analysis ignores the associated line loss (*i.e.*, inefficiency) due to potentially longer transmission lines.[319] The analysis further ignores the requirements of siting electricity generating sources in locations necessary to meet local grid reliability considerations. Considering these factors, it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, and the EPA has therefore determined that phase 2 standards of performance in the 2024 CPS for new base

[318] If a storage site does not have enough available natural gas to fuel a new base load combustion turbine, or enough transmission capacity to deliver the generated electricity to end users, infrastructure would have to be developed prior to the new combustion turbine commencing operation. Developing that infrastructure could result in additional costs to the owner or operator of the new base load combustion turbine.

[319] Although transmission lines conduct electricity, they have some resistance that results in dissipation of the electrical energy in other forms (*e.g.*, heat). As a result, when transmitted over long distances, the electric energy delivered to an end user is less than the electric energy produced at the generating source (in this case, a stationary combustion turbine).

load combustion turbines are not achievable. Additionally, similar to coal-fired steam generating units, much of the necessary CCS infrastructure would likely be developed by external parties over whom the owners and operators of regulated facilities have limited control. This complicates deployment and has the potential to cause or exacerbate delays, providing further support for the conclusion that the January 1, 2032, compliance date and the degree of emission limitation are unachievable.

d. Conclusion

The EPA is finalizing the determination that 90 percent CCS has not been adequately demonstrated nor shown to have reasonable costs and thus is not the BSER for base load stationary combustion turbines. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is finalizing the determination that the phase 2 standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. Accordingly, the Agency is finalizing repeal of the phase 2 requirements for base load combustion turbines.

e. Implications for Evaluation of Best Available Control Technology (BACT) for Prevention of Significant Deterioration (PSD) Permitting

Sources subject to 40 CFR part 60, subparts NSPS TTTT and NSPS TTTTa may be subject to a component of the major NSR program known as the PSD program.

Part C of title I of the CAA contains the requirements for the PSD program. This program sets forth procedures for the preconstruction review and permitting of new and modified stationary sources of air pollution locating in areas meeting the NAAQS (“attainment” areas) and areas for which there is insufficient information to classify an area as either attainment or nonattainment (“unclassifiable” areas). Sources subject to PSD must, among other requirements, demonstrate that construction or modification will not cause or contribute to a violation of any NAAQS or PSD increment,[320] and comply with the emission limitations that reflect the BACT "for each pollutant subject to regulations" under the CAA.[321] The EPA regulations for the PSD program are contained in 40 CFR 51.166 (applicable to air agencies that issue permits under EPA-approved SIPs) and 40 CFR 52.21 (the federal PSD program applicable to permits issued by the EPA or air agencies to which the EPA has delegated authority to implement the federal PSD program). Most PSD permits are issued by State and local air agencies, subject to federally enforceable rules in State Implementation Plans. There are a smaller number of programs where State, local, or Tribal permitting authorities have delegated federal authority to issue permits on behalf of the EPA or where the EPA directly issues PSD permits.

Revisions to the emissions standards in this rulemaking pursuant to CAA section 111 will impact the minimum requirements of BACT in the PSD program. The BACT requirement is the maximum degree of emission reduction a specific source can achieve on a case-by-case basis considering the energy, environmental, and economic impacts of available control measures. The definition of "best available control technology" in CAA section 169(3) states that, "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 section 7411 [CAA section 111] or 7412 [CAA section 112] of this title."[322] In other words, the CAA specifies that BACT cannot be set at an emission control level that is less stringent than that which any applicable standard of performance under the NSPS requires. An applicable NSPS must always be met and provides a "floor" for the BACT requirement; however, a BACT determination could be more stringent than the NSPS. As such, the GHG emission limits

[320] CAA section 165(a)(3), 42 U.S.C. 7475(a)(3).
[321] CAA sections 165(a)(4) and 169(3), 42 U.S.C. 7475(a)(4), 7479(3).
[322] *See also* 40 CFR 51.166(b)(12), 52.21(b)(12) (defining BACT).

the EPA is repealing in this NSPS rulemaking, including the standards for new base load combustion turbines based on 90 percent CCS, will no longer be the “BACT floor” for GHG emissions from sources in the applicable category. The EPA acknowledges that sources and air agencies have some flexibility in implementation of BACT and may continue to consider certain limits and/or controls that are more stringent than the BACT floor. The EPA acknowledges that changing applicable standards under the NSPS can result in implementation impacts in the context of PSD and BACT. The EPA provides additional discussion in chapter 5.3 of the RTC on implications to BACT for PSD permitting related to the 2024 efficiency-based standards in 40 CFR part 60, subpart TTTTa.

2. Summary of Substantial Comments on the 2024 Efficiency-Based Requirements for New Intermediate and Base Load Combustion Turbines

In the June 2025 NPRM, the EPA broadly solicited comment on the BSER determinations and standards of performance for all new and reconstructed combustion turbines. While the EPA is not finalizing changes to the requirements for new or reconstructed combustion turbines other than removing the phase 2 CCS-based requirements for new base load combustion turbines as discussed in section IV.C.1 of this preamble, the Agency notes that commenters specifically raised several concerns on the achievability of the 2024 efficiency-based standards for new intermediate load and base load combustion turbines. Those comments are summarized in this section of the preamble. Additional comments are summarized in the RTC.

Comments: Several commenters raised concerns over the achievability of the efficiency-based standards for new combustion turbines. Commenters cited issues including the need to account for variability in operating load and ambient conditions affecting performance and that many combustion turbine models that could be intermediate load or base load would be unable to meet the standards. Commenters also raised concerns about the limited availability of combustion turbines that could meet the standards, particularly considering load growth. Commenters also stated that efficiency can degrade over time due to normal wear. Commenters also cited uncertainty in how turbines will operate in the future.

Response: The EPA acknowledges the commenters' concerns regarding the 2024 efficiency-based standards for new combustion turbine EGUs. While the EPA is not repealing or otherwise revising the 2024 efficiency-based standards in this action, the Agency notes that it is simultaneously issuing a supplemental proposal soliciting additional public comment on the underlying question raised in the primary basis of the June 2025 NPRM: Whether the EPA lacks statutory authority to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. That action, if finalized as proposed, would repeal all GHG standards for the fossil fuel-fired EGU source category, including the 2015 and 2024 GHG standards, and would thus resolve commenters' concerns.

3. Conclusion

Based on the EPA's review of the BSER and the achievability of the standards, and for the reasons detailed in this section of the preamble, the EPA is repealing the 2024 phase 2 CCS-based emission standards finalized in the 2024 CPS for new base load stationary combustion turbines, codified in 40 CFR part 60, subpart TTTTa.

D. Consideration of Alternatives

The EPA is determining that it is not necessary to analyze and promulgate alternatives to the repeal of the emission guidelines and standards of performance in this action. The purpose of this rule is to provide near-term relief from the 2024 CPS requirements that the EPA now considers unlawful, infeasible, or otherwise unreasonable. This action is not intended to establish replacement standards. Although CAA section 111 generally requires the EPA to regulate existing sources once the EPA has set standards for new sources, the statute does not require the Agency to do so within a particular timeframe. For that reason, the EPA is not legally obligated to promulgate replacement standards in this rulemaking. Nor is it appropriate to do so, for the following reasons:

First, the EPA's approach in this rulemaking is consistent with the incremental way agencies often proceed, and courts have recognized that agencies may act in steps rather than all at once. [323] The EPA's decision not to immediately move forward with alternatives is also supported by its simultaneous proposal to find that it lacks authority under CAA section 111 to regulate GHG emissions from fossil fuel-fired power plants. If that proposal is finalized, any replacement BSER determinations, standards of performance, or compliance schedules would become unnecessary. Thus, promulgating alternatives now could prove to be futile and wasteful. If the EPA does not finalize that separate proposal, the Agency could revisit whether alternatives to the standards repealed in this action should be developed and promulgated. For now, however, the EPA believes it is reasonable to proceed without doing so.

The EPA also notes that it already considered and rejected several alternatives in the 2024 CPS. For long-term coal-fired steam generating units, the EPA evaluated 90 percent CCS, partial CCS at lower capture rates, natural gas co-firing, and heat-rate improvements. The EPA rejected partial CCS because it would produce substantially smaller reductions at higher cost, and because it considered 90 percent CCS achievable. In addition, the IRC section 45Q tax credit might not be available to offset partial CCS costs. In this final rule, the EPA now rejects the conclusion that 90 percent CCS is adequately demonstrated and achievable, and it further concludes that the IRC section 45Q tax credit should not be counted in evaluating the BSER costs of CCS. As a result,

[323] *Fox Television Stations*, 556 U.S. at 522; *see also Pub. Safety Spectrum All.*, *supra* (it was reasonable for the FCC to defer making relevant decisions to a subsequent action).

the EPA believes partial CCS would be even more expensive than previously thought. The EPA likewise determined that natural gas co-firing would amount to impermissible generation shifting and therefore cannot serve as BSER. Heat-rate improvements were also rejected because they would provide only limited reductions and could create a rebound effect.

For medium-term coal-fired EGUs, the EPA similarly considered and rejected CCS and heat-rate improvements in the 2024 CPS. That prior analysis reinforces the EPA's conclusion that further consideration of alternatives is unnecessary here. For new baseload combustion turbines, the EPA considered lower-emitting fuels, highly efficient generation, and hydrogen co-firing. The EPA has not changed its prior conclusion that highly efficient generation remains an appropriate BSER for those units. The Agency previously found that lower-emitting fuels would reduce emissions only modestly and that uncertainties about the cost of low-GHG hydrogen prevented the EPA from treating hydrogen as part of the BSER at that time. Taken together, these prior evaluations support the EPA's view that additional alternatives to the repealed standards do not need to be analyzed and promulgated in this rulemaking.

V. Statutory and EO Reviews

Additional information about these statutes and EOs can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

A. EO 12866: Regulatory Planning and Review and EO 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action under EO 12866 section 3(f)(1) that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in the course of EO 12866 review have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final Partial Repeal of the Carbon*

Pollution Standards for Fossil Fuel-Fired Electric Generating Units, is available in the docket.

The EPA presents the estimated present value (PV) and equivalent annualized value (EAV) of the projected cost savings for the power sector of this final repeal for the years 2026 to 2047 in 2024 dollars, discounted to 2025. In addition, the EPA presents the results for specific snapshot years, consistent with historical practice. These snapshot years are 2030, 2035, 2040, and 2045. The benefit-cost analysis, which is in the RIA for this rulemaking, is available in the docket.

The analysis considers the power industry's compliance costs as the change in electric power generation costs due to this final repeal. Table 1 presents the estimates of compliance cost savings of this final rule for the power sector.

Table 1—Present Value (PV) and Equivalent Annualized Value (EAV) of the Compliance Cost Savings

[Billion 2024$, Discounted to 2025]

3% Discount Rate		**7% Discount Rate**	
PV	**EAV**	**PV**	**EAV**
160	10	95	8.6

Note: For the reasons the EPA describes in section 4 of the RIA, the Agency has not monetized several impact categories, including the potential health and welfare impacts of changes in emissions. Therefore, this table does not include those impact categories.

The compliance cost savings in Table 1 are the estimated change in expenditures by the power sector due to this final repeal, which include changes in taxes paid and credits received. The analysis also considers the real resource cost savings due to this final repeal, which are the change in the total avoided cost of resources used by the power sector, which includes capital, labor, fuel, and material inputs, that would have been used for compliance. In contrast to the compliance cost savings in Table 1, the real resource cost savings do not include transfers, such as taxes paid or tax credits, that shift who is paying for the inputs for compliance but do not reduce the social cost. The use of tax credits would have reduced costs from the perspective of firms in the power sector but would have led to a use of resources that are a cost from a societal perspective. These societal costs will now be avoided because of this final action. Over the 2026 to 2047 period, the PV of the estimated real resource cost savings is $280 billion using a three percent discount rate and $180 billion using a seven percent discount rate discounted to 2025. Over this same timeframe, the EAV of the estimated real resource cost is $18 billion using a three percent discount rate, and $16 billion using a seven percent discount rate.

Changes in resources used by the power sector may cause economic interactions in other markets that affect other sectors and households. To evaluate the economy-wide social costs and economic impacts of the action, the EPA used the peer-reviewed CGE model SAGE. The PV of the social cost savings estimated in SAGE for the action is approximately $310 billion (2024 dollars) between 2026 and 2047 (discounted to 2025). The EAV is $23 billion. Note that SAGE does not account for the effects of changing environmental quality as a result of this action. The RIA further describes the methodology and the distinctions between compliance costs, real resource costs, and social costs.

The EPA is obligated to present the agency's best scientific understanding and the implications of that science when developing policies and regulations. However, historically, the EPA's analytical practices may not have presented the full range of uncertainties and associated confidence level regarding the potential benefit estimates from reduction in exposure to particulate matter ($PM_{2.5}$) and ozone. In addition, the science regarding the exposure, health effects from exposure and valuation of reduction in health effect are evolving with better data and methods, especially at low concentrations of PM and ozone. Some of the sources of uncertainties include the set of assumptions used in projecting the health impact of reducing PM. These projections are based on a series of models that take into account emissions changes, resulting distributions of changes in ambient air quality, the estimated reductions in health effects from changes in exposure, and the composition of the population that will benefit from the reduced exposure. Each component includes assumptions, each with varying degrees of uncertainty.

In addition, the EPA historically provided point estimates rather than just ranges of emission-related effects or only quantifying emissions when monetizing proved to be too uncertain. Therefore, to address these concerns, the EPA is refraining from providing primary estimates resulting from changes in $PM_{2.5}$ and ozone exposure resulting from changes in direct $PM_{2.5}$, NO_X and VOC emissions but will continue to quantify the emissions until the Agency is confident enough in the modeling to robustly monetize those impacts.

To illustrate the impacts of the final repeal, including the cost savings of not deploying CCS as a control strategy and the resultant impact on real resource costs through diminished uptake of the IRC section 45Q tax credit, the EPA assumes that 90 percent CCS is allowed in the model's solution set in the modelling supporting the current RIA. However, to illustrate the sensitivity of the results to the viability of 90 percent CCS as a control strategy, the EPA also developed a modeling scenario assuming 90 percent CCS is not allowed in the model's solution set. These model runs and a memorandum describing key results are available in the docket for this action.[324]

B. EO 14192: Unleashing Prosperity Through Deregulation

This action is considered an EO 14192 deregulatory action. For regulatory accounting purposes, the estimated present value and annualized value of the cost savings

[324] See memorandum entitled "IPM Sensitivity Runs Memo" in the docket for this rulemaking.

of this rule are $102 billion and $7 billion, respectively (7 percent discount rate, 2024 dollars, 2024 present value year, perpetuity time horizon). Details on the estimated cost savings of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units*, is available in the docket.

C. Paperwork Reduction Act (PRA)

The information collection activities in this final action have been submitted for approval to the OMB under the PRA. The EPA is finalizing amendments to the information collection request (ICR) for 40 CFR Part 60, subpart UUUUb. Details on the amendments for this subpart are described below. The EPA is not finalizing amendments to the ICRs for 40 CFR Part 60, subparts TTTT and TTTTa.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves the ICR, the Agency will announce that approval in the FR and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

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

This action does not impose any new information collection burden under the PRA.

3. 40 CFR Part 60, Subpart UUUUb

The ICR document that the EPA prepared has been assigned EPA ICR number 2770.04. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This action repeals requirements on state governments with existing fossil fuel-fired steam generating units. The information collection requirements are based on the recordkeeping and reporting burden reduction associated with developing, implementing, and enforcing a state plan to limit GHG emissions from these existing EGUs.

Respondents/affected entities: States with one or more designated facilities covered under subpart UUUUb.

Respondent's obligation to respond: No longer mandatory.

Estimated number of respondents: 43.

Frequency of response: No response required.

Total estimated burden reduction: 89,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost savings: $11.7 million, includes $35,000 annualized capital or operation & maintenance costs.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the EPA concludes that the impact of concern for this rule is any significant adverse economic impact on small entities and that the Agency is certifying that this final rule will not have a significant economic impact on a substantial number of small entities because this action relieves regulatory burden on the small entities subject to the rule. 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 emission standards on existing sources, and it is those requirements that could potentially impact small entities. Thus, the repeal of the requirements in the emission guidelines will not impose any requirements on small entities. The repeal of requirements for new, modified, and reconstructed fossil fuel-fired EGUs will relieve regulatory burden on the small entities subject to the rule. As outlined in section 5.3 of the RIA for this rulemaking, the EPA identified 14 potentially affected small entities that own NGCC units considered in the analysis. Under the repeal, the EPA projected compliance cost savings of $143 million for these small entities in 2035. Consequently, the EPA expects that this deregulatory action will relieve the regulatory burden for facilities that, absent this repeal, would be affected by the provisions from the 2024 CPS. As a result, this action will not have a significant economic impact on a substantial number of small entities under the RFA. We have therefore concluded that this action will relieve regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million (adjusted annually for inflation) or more (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any State, local, or Tribal governments or the private sector.

F. EO 13132: Federalism

This action does not have federalism implications. It 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.

G. EO 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications as specified in EO 13175. It will not have substantial direct effects on Tribal governments, on the relationship between the Federal Government and Indian Tribes, or on the distribution of power and responsibilities between the Federal Government and Indian Tribes, as specified in EO 13175. Thus, EO 13175 does not apply to this final action.

However, because of Tribal interest on this action and consistent with the EPA Policy on Consultation with Indian Tribes, the EPA offered government-to-government consultation with Tribes. Tribal consultations were completed following the proposal at the request of the Summit Lake Paiute Tribe, the Coeur d'Alene Tribe, the Bois Forte Tribe, and the Ak-Chin Indian Community. Summaries of these consultations are included in the rulemaking docket.

H. EO 13045: Protection of Children From Environmental Health Risks and Safety Risks

EO 13045 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 subject to EO 13045 because it is a significant regulatory action under section 3(f)(1) of EO 12866. The 2024 CPS was anticipated to reduce emissions of various pollutants and some of the benefits of reducing these pollutants would have accrued to children. This final action is expected to decrease the impact of the emissions reductions estimated from the 2024 CPS on these benefits. However, as discussed in the RIA, the EPA does not quantify the health effects of air pollution in this final rule.

This final action does not affect the level of public health and environmental protection already being provided by existing NAAQS and other mechanisms in the CAA. This final action does not affect applicable local, State, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.

I. EO 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution or use of energy over the analysis period (2026–2047) based on the results presented in the RIA accompanying this rulemaking.

J. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This rulemaking does not involve technical standards; however, with the removal of 40 CFR part 60 subpart UUUUb, the EPA is also removing ANSI No. C12.20-2010 from § 60.5860b that has been approved for incorporation by reference.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit the rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Lee Zeldin,
Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends part 60 of title 40, chapter I, of the Code of Federal Regulations as follows:

PART 60 – STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A - General Provisions

2. Amend § 60.17 by revising paragraph (d)(1) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(d) * * *

(1) ANSI No. C12.20-2010 American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Classes (Approved August 31, 2010); IBR approved for §§ 60.5535(d); 60.5535a(d).

* * * * *

Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

3. Revise § 60.5508 to read as follows:

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit or an integrated gasification combined cycle (IGCC) facility that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, or commences modification after January 8, 2014. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction after January 8, 2014, but on or before May 23, 2023, or commences reconstruction after June 18, 2014, but on or before May 23, 2023. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

4. Amend § 60.5580 by revising the definition of *System emergency* to read as follows:

§ 60.5580 What definitions apply to this subpart?

*   *   *   *   *

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 which should follow NERC Reliability Standard EOP-011-2, its successor, or equivalent.

*   *   *   *   *

Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

5. Revise the heading of subpart TTTTa to read as set forth above.

6. Revise § 60.5508a to read as follows:

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

7. Amend § 60.5509a by:

a. Revising the introductory text of paragraph (a);

b. Removing and reserving paragraph (b)(1);

c. Revising paragraph (b)(4); and

d. Removing and reserving paragraph (b)(7).

The revisions read as follows:

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

* * * * *

(b) * * *

(4) Your EGU serves a generator along with other stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each stationary combustion turbine) is 25 MW or less.

* * * * *

8. Amend § 60.5525a by revising paragraphs (a)(3) and (c)(2) and (3) to read as follows:

§ 60.5525a What are my general requirements for complying with this subpart?

* * * * *

(a) * * *

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines firing fuels with a lower CO_2 emissions rate than natural gas (e.g., hydrogen) are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2 \text{ emissions standard} = \left[BLER_L + \frac{BLER_S - BLER_L}{BLR_L - BLR_S} \times (BLR_L - BLR_A)\right] \times \left[\frac{HIER_A}{HIER_{NG}}\right]$$
(Eq. 2)

Where:
CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh).
$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net).
$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net).
BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h).
BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h).
BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h).
$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMbtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu).
$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu).

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2 \text{ emissions standard} = ILER \times \left[\frac{HIER_A}{HIER_{NG}}\right] \text{ (Eq. 3)}$$

Where:
CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh).
ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 530 kg/MWh-gross (1,170 lb CO_2/MWh-gross) or 540 kg CO_2/MWh-net (1,190 lb CO_2/MWh-net).
$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu).
$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu).

*   *   *   *   *

(c)   *   *   *

(2) For a reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraph (c)(3)(i) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you must comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) [Reserved]

9. Amend § 60.5535a by revising paragraphs (b)(1) and (g) to read as follows:

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

* * * * *

(b) * * *

(1) For affected EGUs, you may install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (e.g., carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture

value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

* * * * *

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the “stack operating time” (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

10. Amend § 60.5540a by:

a. Revising paragraphs (a)(5)(i) and (a)(8); and

b. Removing paragraph (c).

The revisions read as follows:

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) * * *

(5) * * *

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \text{ (Eq. 1)}$$

Where:
$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in paragraph (a)(1) of this section) in MWh.
$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.
$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.
$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.
$(Pe)_A$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.
$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.
$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.
$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.
TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

* * * * *

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraph (a)(8)(i) of this section.

(i) For affected combustion turbines in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) [Reserved]

* * * * *

11. Amend § 60.5555a by:

a. Revising paragraphs (a)(2)(v) and (c)(3)(iii); and

b. Removing paragraphs (f) and (g).

The revisions read as follows:

§ 60.5555a What reports must I submit and when?

(a) * * *

(2) * * *

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 to this subpart) with which your affected EGU must comply; and

* * * * *

(c) * * *

(3) * * *

(iii) For reconstructed units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

* * * * *

12. Amend § 60.5560a by revising paragraph (f) to read as follows:

§ 60.5560a What records must I maintain?

* * * * *

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 to this subpart.

* * * * *

13. Amend § 60.5580a by:

a. Removing the definition of *Coal-fired Electric Generating Unit*;

b. Revising the definitions of *Electric Generating Units or EGU* and *Gross energy output*;

c. Removing the definition of *Integrated gasification combined cycle facility or IGCC*; and

d. Revising the definitions of *Intermediate load combustion turbine*, *Low load combustion turbine*, *Net-electric sales*, and *System emergency*.

The revisions read as follows:

§ 60.5580a What definitions apply to this subpart?

*   *   *   *   *

Electric Generating Units or EGU means any stationary combustion turbine that is subject to this rule (*i.e.*, meets the applicability criteria).

*   *   *   *   *

Gross energy output means:

(1) For stationary combustion turbines, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) [Reserved]

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps, that difference divided by 0.95, plus 100 percent of the useful thermal output.

*   *   *   *   *

Intermediate load combustion turbine means a stationary combustion turbine that is not a low load or base load combustion turbine. An intermediate load combustion turbine supplies more than 20 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and supplies 40 percent or less of its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis.

*   *   *   *   *

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis.

*   *   *   *   *

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus purchased power and the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchased power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

* * * * *

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 which should follow NERC Reliability Standard EOP-011-2, its successor, or equivalent.

* * * * *

14. Revise table 1 to subpart TTTTa to read as follows:

Table 1 to Subpart TTTTa of Part 60 - CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 720 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Table 2 to Subpart TTTTa of Part 60 [Removed and Reserved]

15. Remove and reserve table 2 to subpart TTTTa.

16. Revise table 3 to subpart TTTTa to read as follows:

Table 3 to Subpart TTTTa of Part 60 – Applicability of Subpart A of This Part to This Subpart

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	

§ 60.2	Definitions	Yes.	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes.	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes.	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes.	Administrator can approve alternate methods.
§ 60.8(c)-(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)-(h), (j)	Monitoring requirements	No.	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes.	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	No.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	

§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes.	Does not apply to notifications under § 75.61 of this chapter or to information reported through ECMPS.

Subpart UUUUb – [Removed and Reserved]

17. Remove and reserve subpart UUUUb, consisting of §§ 60.5700b through 60.5880b.

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