EPA's Proposed Greenhouse Gas Emission Standards for Power Plants are Consistent with Statutory Factors and Market Trends

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In this summary, we explain the legal basis for this proposed rule, including EPA's statutory mandate and relevant regulatory history. We describe EPA's proposed standards for existing coal, new gas, and existing gas units and highlight areas in which EPA is seeking comment, particularly related to the scale, timing, and pace for complying with the emission limits. Finally, we review compliance timelines and state plans, EPA's environmental justice analysis, and impacts of the proposal on climate change, public health, and grid reliability.

Our key takeaways include:

- EPA proposes greenhouse gas (GHG) emissions standards for coal- and gas-fired power plants based on its longstanding legal authority and regulatory history. The standards reflect recent trends showing that industry is already investing in control technology at lower costs due to Congressional investments through the Inflation Reduction Act (IRA).
    - Section 111 of the Clean Air Act (CAA) requires EPA to identify standards for large emission sources based on control technologies that are adequately demonstrated considering cost and energy requirements and environmental impacts.
- EPA focuses on baseload plants that plan to operate far into the future to ensure they control GHG emissions and is proposing performance standards based on carbon capture and sequestration (CCS) technologies, and for natural gas plants, EPA also includes a performance standard for using low-GHG hydrogen.
- EPA proposes additional pathways for power plants to opt into if their units will serve different roles than baseload or have plans to retire in the near future.
- EPA summarizes and responds to concerns expressed by community stakeholders regarding the use of low-GHG hydrogen and CCS.
- EPA requests comments on a range of considerations related to the proposed standards, and comments will be due 60 days after publication in the Federal Register.

Introduction

On May 11, 2023, EPA proposed new greenhouse gas emission limits and guidelines for new and existing fossil fuel-fired power plants.[1] EPA issued the proposal under section 111 of the Clean Air Act, which directs EPA to set standards based on the application of the "best system of emission reduction" (BSER) that is adequately demonstrated, and considers cost, energy requirements, and other statutory factors.

[1] Environmental Protection Agency, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, RIN 2060-AV09 (May 11, 2023) (hereinafter "Proposed Rule"); proposed regulatory text available here: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants.

EPA designed the rule to be consistent with the power sector's long-term and ongoing transition to cleaner-burning fuels. EPA proposes to set initial compliance deadlines no earlier than 2030, to provide time for power plants to install and operate the controls on which EPA bases emission limits. EPA also proposes to allow companies to opt into different compliance pathways depending on how long a company intends to operate older units and how a company intends to operate its plant.

See our visual quick take summarizing EPA's proposed standards here.

EPA's proposed plant-specific rule differs from the Obama administration's Clean Power Plan, which the Supreme Court rejected in *West Virginia v. EPA* based on EPA's generation shifting approach. This new proposal is based on companies installing controls at a plant that EPA determines are adequately demonstrated. Congress's enactment of the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) significantly lowered the cost of both carbon capture and sequestration (CCS) and the use of low-GHG hydrogen to reduce natural gas-fired plants' CO_2 emissions. EPA determines both technologies are adequately demonstrated and that the costs for both are reasonable.

EPA's proposal includes an assessment of the anticipated environmental justice-related effects of the rule, as required under Executive Orders 12898 and 13985, and responds to concerns from potentially impacted communities regarding the proposal's reliance on CCS and hydrogen technologies for BSER for certain facilities.

Legal Basis for this Proposed Rule

In this section, we review EPA's statutory authority, and in particular the Clean Air Act's phrase "best system of emission reduction." We also review the rule's regulatory history and the market shifts, technology developments, and legislative changes that set the context for this rulemaking.

Statutory Authority

CAA section 111 requires EPA to identify source categories that emit dangerous air pollutants and regulate new and existing sources of those emissions. In setting regulations, EPA must determine the "best system of emission reduction [(BSER)] . . . adequately demonstrated" and consider cost, non-air quality health and environmental impacts, and energy requirements.[2] Additionally, EPA may categorize sources based on their characteristics that inform the BSER determination.[3]

[2] 42 U.S.C. § 7411(a)(1); Proposed Rule at 15–16.
[3] Proposed Rule at 15–16.

When EPA determines the BSER for an emissions source, it must then determine the "degree of emission limitation" achievable by applying the BSER. For new sources, EPA sets new source performance standards (NSPS) that reflect the degree of emission limitation. For existing sources, EPA includes a degree of emission limitation in the emission guidelines (EGs), then states must adopt state plans consistent with those guidelines.[4] Under the CAA, EPA must review new source performance standards every eight years and has the authority to review emission guidelines for existing sources as well.[5]

Best System of Emission Reduction (BSER)

EPA explains that an "adequately demonstrated" BSER is "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[6] EPA notes that courts have found that the system need not be in "actual routine use," and that the agency may make a projection based on existing technology, lead time, and feasibility.[7] EPA provides the example of selective catalytic reduction (SCR) for industrial boilers, which the D.C. Circuit upheld as adequately demonstrated to reduce nitrogen oxides (NO_X) emissions even though it was a "new technology." In that case, the court explained that "section 111 'looks toward what may fairly be projected for the regulated future, rather than the state of the art at present.'"[8]

Once EPA determines the BSER and degree of emission limitation, each state submits a plan to EPA that sets standards of performance for the existing facilities within that state. EPA notes that while it sets a presumptive standard of performance, "a state retains discretion in applying such a presumptive standard of performance to any particular designated facility," including consideration of remaining useful life of the source and other factors.[9]

Regulatory History: The Clean Power Plan, Affordable Clean Energy Rule, and West Virginia v. EPA

There is a "robust regulatory history" about section 111 and a body of caselaw interpreting this section.[10] EPA first promulgated rules controlling CO_2 emissions from fossil fuel-fired electricity generating units (EGUs) in 2015. Those regulations included the Clean Power Plan, which EPA repealed in 2019 and replaced with the Affordable Clean Energy rule (ACE).[11] That rule set emission guidelines for existing coal-fired steam-generating units based on modest heat rate improvements at each facility.[12] For more on this history, see EELP's Regulatory Tracker page.

[4] *Id.*
[5] *Id.* at 104.
[6] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), cert. denied, 416 U.S. 969 (1974); Proposed Rule at 125–26.
[7] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973); Proposed Rule at 126.
[8] *Lignite Energy Council*, 198 F.3d at 934 (citing *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973)); Proposed Rule at 126.
[9] 42 U.S. Code § 7411(d)(1).
[10] Proposed Rule at 16.
[11] 84 Fed. Reg. 32523–24 (July 8, 2019); Proposed Rule at 111.
[12] 84 Fed. Reg. 32535 (July 8, 2019), Proposed Rule at 111.

Although the CPP had been repealed and replaced and would not have gone back into effect under President Biden, the Supreme Court struck it down in June 2022. In *West Virginia v. EPA*, the Supreme Court recognized that historically, the EPA had considered "measures that improve the pollution performance of individual sources" and followed a "technology-based approach" in identifying systems of emission reduction, including "the sort of 'systems of emission reduction' [the EPA] had always before selected."[13] As EPA notes in this proposal, the Court did not "define the outer bounds of the meaning of 'system,'" but did include "fuel switching, add-on controls, and efficiency improvements" as "within the scope of prior practice as recognized by the Supreme Court."[14]

Regarding the appropriate roles for EPA and states, the Court explained that "[a]lthough the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d). The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved…The States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA."[15]

Market Shifts, Technology Advancements, and Legislative Developments

EPA explains that several important developments, including market changes, technology advancements, and new legislation, inform its analysis and determination of BSER in this proposed rule.

Market shifts: EPA notes that for more than a decade, the power sector has undergone "substantial transition and structural change" in generation capacity and mix due to a range of factors, including unit retirements, technology innovation, shifts in price and availability of fuels, changes in demand and consumer preference, and state and federal policy.[16] EPA explains that as a result, between 2010 and 2021, fossil fuel-fired generation dropped from roughly 70 percent of total generation to 60 percent. During that time, coal generation fell from 46 percent to 23 percent of generation.[17]

Technology advancements: For CCS, EPA notes that projected costs have fallen due to process improvements as well as congressional investment described below.[18] EPA explains that it considered the state of CCS technology in developing the proposal and describes current projects including SaskPower's Boundary Dam Unit 3, AES's Warrior Run, and Shady Point coal-fired power plants and Bellingham Energy Center's use of CCS in an existing combined cycle combustion turbine unit, among others.[19] EPA also notes developments in hydrogen co-firing, including planned utility and merchant generator projects.

Legislative Developments: EPA explains that both the Infrastructure Investment and Jobs Act[20] and the Inflation Reduction Act[21] cut costs of CCS and hydrogen for power plants, which supports their inclusion as

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[13] *W. Virginia v. Env't Prot. Agency,* 142 S. Ct. 2587, 2611 (quoting the Clean Power Plan); Proposed Rule at 124.
[14] Proposed Rule at 125.
[15] *W. Virginia v. Env't Prot. Agency*, 142 S. Ct. 2587, 2601–02 (2022).
[16] Proposed Rule at 62.
[17] *Id.* at 26.
[18] *Id.* at 56.
[19] *Id.* at 56–57.
[20] Infrastructure Investment and Jobs Act, Public Law No. 117-58 (Nov. 15, 2021).
[21] Inflation Reduction Act, Public Law No. 117-169 (Aug. 16, 2022).

BSER in the rule.[22] The IRA extended and increased by 70 percent the tax credit for CCS, which "in effect provide[s] a significant stream of revenue for sequestered CO_2 emissions."[23] This tax credit is often called "Section 45Q" in reference to its location in the Internal Revenue Code. The legislation also provides support for CO_2 pipeline infrastructure and tax credits to facilitate clean hydrogen production, called "Section 45V," which significantly changes the costs for hydrogen co-firing controls.[24]

Proposed Standards

In this section, we review the proposed standards for existing coal, new gas plants, and existing gas plants, including EPA's BSER determination and key questions that EPA raises for comment.

EPA proposes a set of standards for fossil fuel-fired power plants that it believes will reduce GHG emissions in a cost-effective way that is consistent with its statutory mandate and with caselaw.[25] EPA proposes that the BSER is a "set of controls that, depending on the subcategory, include either highly efficient generation plus use of CCS or highly efficient generation plus co-firing low-GHG hydrogen."[26]

Specifically, EPA proposes standards for existing fossil fuel-fired steam generating EGUs, including coal plants, which reflect the application of CCS and natural gas co-firing. EPA also proposes standards for new and reconstructed fossil fuel-fired combustion turbine EGUs (i.e., natural gas-fired units) based on efficient generating practices, hydrogen co-firing, and CCS. The agency also proposes emission guidelines for large and frequently used existing stationary combustion turbines (i.e., gas-fired units).

EPA also proposes phased compliance for certain sources. This multi-phase standard would be effective upon finalization, meaning affected sources must meet an emission-limiting standard in the first phase and then are subject to more stringent standards beginning in 2032 or later during the second and third phases. EPA explains that D.C. Circuit caselaw supports the agency's authority to set BSER based on controls that require some amount of "lead time" and EPA has promulgated several prior rulemakings under CAA section 111(b) that serve as precedent for this multi-phase approach.[27]

[22] Proposed Rule at 81–82.
[23] The CCS tax credit equals $85 per metric ton for CO_2 captured and securely stored in geologic formations and $60 per metric ton for CO_2 captured and utilized or stored in conjunction with enhanced oil recovery. *Id.* at 81, 410.
[24] *Id.* at 82.
[25] *Id.* at 13.
[26] *Id.* at 186.
[27] *Id.* at 187–88.

Existing and Modified Steam Generating Units, Including Coal-Fired Plants

EPA proposes new BSER determinations and emission guidelines for existing and modified steam generating units.[28] To do this, EPA proposes to repeal and replace the 2019 ACE rule, explaining that since it was promulgated, CCS technology has improved and costs have fallen, and natural gas co-firing costs are lower due to a decrease in the cost differential between gas and coal.[29] EPA proposes in this new rule to base BSER on CCS.

EPA acknowledges that for CCS to be cost-effective, companies will need to operate the CCS unit for a sufficient length of time in order to spread out capital cost recovery.[30] Because that duration of operation may not be expected for all units and might be inconsistent with industry trends, EPA proposes three subcategories that units can opt into based on more limited operating timelines and load levels, with different BSER and emission limitations for each of those subcategories. To opt into one of the subcategories, a company must commit to a certain date for permanently ceasing operations, and that date must be included in its state plan. Existing steam generating unit operators must notify the state and EPA of their chosen subcategory and corresponding standards of performance by July 1, 2029 and comply with the appropriate BSER, depending on their subcategory, by January 1, 2030.

EPA notes that over one-third of existing coal-fired steam generating capacity has planned to stop operating by 2032, with half of current capacity planning to halt operating by 2040.[31] EPA explains that it is proposing to include these subcategories in response to industry requests for flexibility*:* "Industry stakeholders have requested that the EPA structure this rule to avoid imposing costly control obligations on coal-fired power plants that have announced plans to voluntarily cease operations, and the EPA proposes to accommodate those requests."[32] Additionally, EPA states that there are precedents for lower standards for nearer-term retirements, including the 2020 Clean Water Act steam electric effluent guidelines.[33] EPA requests comment on a range of elements in this part of the proposed rule, including the retirement dates and load levels used to define each subcategory.[34] We summarize the proposed BSER and emission limit for each subcategory below.

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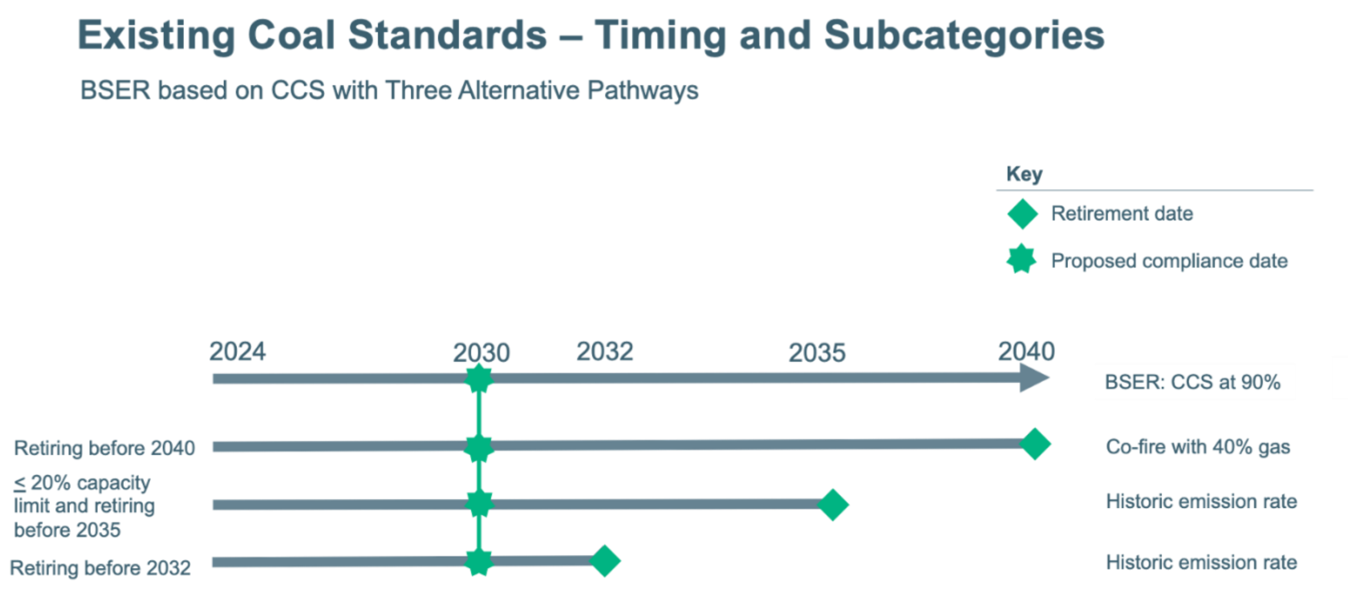
[28] Specifically, a designated facility under this section of the proposed rule is defined as "a fossil fuel fired electric utility steam generating unit (1) in operation or with construction commenced before Jan. 8, 2014 ; (2) serves generator capable of selling greater than 25 MW to a utility power distribution system; and (3) has a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel)." *Id.* at 384–85 (exemptions are listed on p. 386).
[29] *Id.* at 21–22.
[30] *Id.* at 21.
[31] *Id.* at 392.
[32] *Id.* at 61.
[33] Environmental Protection Agency, 2020 Steam Electric Reconsideration Rule, 40 CFR Part 423 (Aug. 31, 2020); Proposed Rule at 392.
[34] Proposed Rule, at 396.



a. Long-Term Units – Coal Plants Planning to Operate Beyond 2040

For existing coal-fired steam generating units that plan to operate beyond 2040, EPA proposes to base BSER on CCS with 90 percent capture and require an emission limit equal to an 88.4 percent reduction in emission rate (pounds of CO_2 per MWh gross). EPA proposes to require these units to install and operate CCS by 2030.[35]

To justify CCS as BSER, EPA explains that the technology is adequately demonstrated "as indicated by the facts that it has been operated at scale and is widely applicable to sources," there are sequestration opportunities across the US, costs are reasonable, especially given lower recent costs and the 45Q tax credit, and non-air quality health and environmental impacts are "not unreasonably adverse."[36] EPA describes several existing projects, including SaskPower's Boundary Dam Unit 3, which has "demonstrated capture rates of 90 percent of the CO_2 in flue gas using solvent-based post-combustion capture retrofitted to existing coal-fired steam generating units."[37] EPA seeks comment on a range of maximum capture rates, including 90 to 95 percent or greater, and an emission limitation of 75 to 90 percent.[38]

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[35] *Id.* at 400.
[36] EPA notes that while CCS is adequately demonstrated on these bases, projects that received assistance under the Energy Policy Act of 2005, referred to as "EPAct05-assisted projects," provide additional support. *Id.* at 401–02.
[37] *Id.* at 403.
[38] *Id.* at 382.

b. Medium-Term Units – Coal Plants Retiring by 2040

EPA proposes this subcategory for plants that plan to retire by 2040. Due to shorter operating timelines and a shorter amortization period for the 45Q tax credit, EPA concludes that CCS would be "less cost effective" for these medium-term units.[39] Instead, EPA proposes natural gas co-firing at 40 percent of annual heat input as BSER, with a 16 percent reduction in emission rate (pounds of CO_2 per MWh gross). EPA states that natural gas co-firing is adequately demonstrated, has reasonable cost, does not have adverse health, environmental, or energy impacts, and achieves "meaningful" reductions.[40] EPA asks for comment on the percent of natural gas co-firing and degree of emission limitation, as well as the time horizons delineating medium-term and long-term units.[41]

c. Near-Term Units – Coal Plants with Annual Capacity Factor Limit Up to 20 Percent and Retiring by 2035

EPA explains that this subcategory is designed for facilities to operate for a slightly longer horizon but as peaking units, at a capacity factor of up to 20 percent. EPA proposes routine methods of operation and maintenance as BSER and an emission rate no greater than the current rate.[42] EPA explains that this approach is already adequately demonstrated since it is the current mode of operation, will not add cost, and will not create adverse health, environmental, or energy impacts. EPA adds that while this standard will not achieve emissions reductions compared to current levels, it will "prevent worsening of emissions rates over time" and will accommodate differences in performance between units.[43] EPA requests comment on a potential BSER for this subcategory based on low levels of natural gas co-firing.

d. Imminent-Term Units – Coal Plants Retiring by 2032

EPA proposes this subcategory to accommodate units with short operating horizons for which EPA concludes additional carbon dioxide control measures are cost-effective. As with near-term units, EPA proposes routine methods of operation and maintenance as BSER, and no increase in emission rate.[44] EPA poses a number of questions for comment, including whether BSER should be based on low levels of natural gas co-firing, whether to retain this subcategory, and whether their standard of performance should reflect an annual total emissions limitation rather than an hourly emission rate to allow greater flexibility.[45]

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[39] *Id.* at 421.
[40] *Id.*
[41] *Id.* at 434.
[42] *Id.* at 438.
[43] *Id.*
[44] *Id.* at 435.
[45] EPA also proposes to revise BSER for large modifications of coal plants to CCS with 90 percent capture of CO_2 to ensure that all coal plants are subject to the same requirements. EPA explains that it does not propose to revise the 2015 NSPS for new coal plants, which is CCS with 16 to 23 percent capture, because it does not expect that companies will build new coal plants. *Id.* at 23.

New Gas Plants

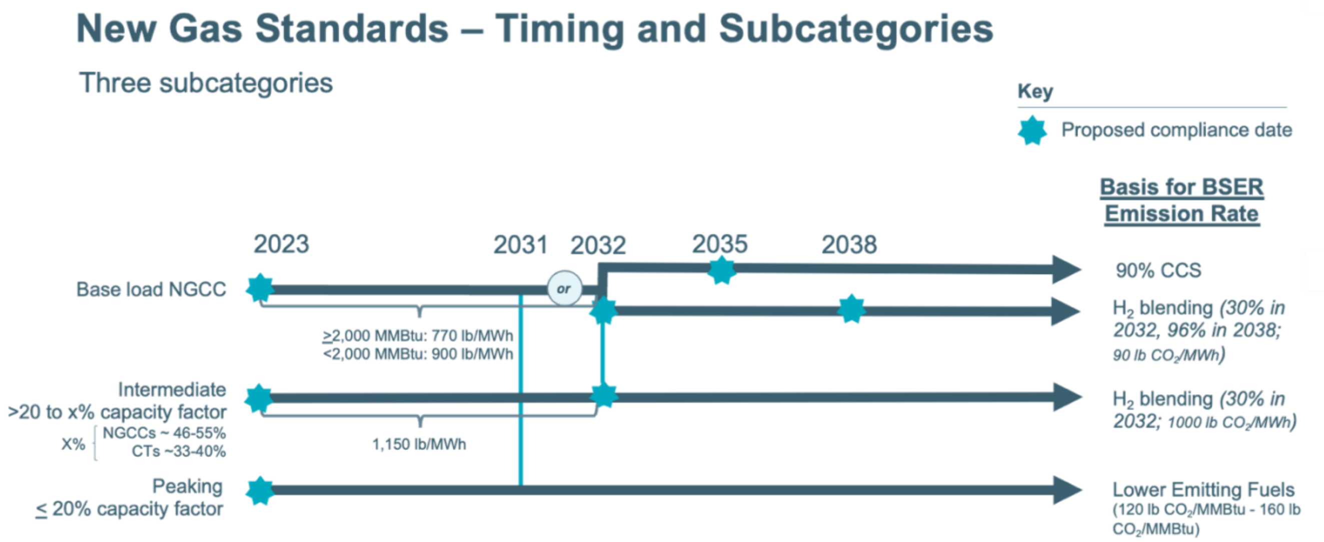
For new and modified gas-fired EGUs[46] EPA proposes multi-phase standards with three subcategories. These standards would replace the current 2015 standards.[47] The proposal would retain a subcategorization based on electric sales thresholds but revise the subcategories. Upon construction, companies would need to ensure a plant meets a specific standard. For the second phase, companies would need to indicate to EPA which pathway they intend to comply with by January 1, 2031.[48]

EPA proposes to delineate new gas plant subcategories by electric sales at a site-specific electric sales threshold, using both a 12-operating-month and 3-year rolling average basis as well as the design efficiency of the combustion turbines, which will be used as an equivalent capacity factor. EPA proposes the following new gas plant subcategories and requests comment on the following sales thresholds for new gas plant subcategories:[49]

Subcategory	Capacity Factor
Low Load/Peaking	≤ 20 percent
Intermediate Load	> 20 percent and ≤ site-specific value determined based on the design efficiency of the affected facility • Between ~ 33 to 40 percent for simple cycle combustion turbines • Between ~ 45 to 55 percent for combined cycle combustion turbines
Base Load	> Site-specific value determined based on the design efficiency of the affected facility • Between ~ 33 to 40 percent for simple cycle combustion turbines • Between ~ 45 to 55 percent for combined cycle combustion turbines

For each subcategory, EPA proposes an emission limit based on BSER.

[46] The Clean Air Act defines new and modified EGUs as those that commence construction or modification after the proposed rule is published in the Federal Register.
[47] Proposed Rule at 149.
[48] *Id.* at 325.
[49] *Id.* at 310–11; see also *id.* at 353–55.



Low Load Combustion Turbines

For the low load combustion turbines (or "peaking") subcategory[50] EPA proposes to base the performance standard on the use of lower emitting fuels (natural gas and/or distillate oil with an emissions rate of 120 to 160 lb CO_2/MMBtu[51]), consistent with EPA's approach for non-base load units for the 2015 standards.[52] EPA does not propose high efficiency technology, CCS, or hydrogen co-firing, explaining that such approaches would not result in cost-effective GHG emission reductions.[53] EPA requests feedback on the costs and technical capabilities of high efficiency technology[54] and on approaches for incorporating hydrogen co-firing, including through a second phase starting in 2032.[55]

Intermediate and Base Load

Phase 1

For intermediate and base load gas plants, EPA proposes BSER based on highly efficient simple cycle and combined cycle technologies, respectively. EPA states that such efficient technology combined with improved operating practices have been demonstrated by multiple facilities for decades.[56] For intermediate load, EPA proposes a performance standard of 1,150 lb CO_2/MWh-gross. For base load EGUs, EPA proposes a performance standard of 770 lb CO_2/MWh-gross for larger combustion turbines with a base load rating of 2,000 MMBtu/h or more. For combustion turbines with a base load rating of less than 2,000 MMBtu/h, EPA

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[50] EPA states that they expect these to generally include simple cycle turbines.
[51] EPA explains that "use of lower emitting fuels would not have any significant adverse energy requirements or non-air quality or environmental impacts, as the EPA determined in the 2015 NSPS." Proposed Rule at 171.
[52] *Id.* at 169.
[53] *Id.* at 172, 175–76.
[54] *Id.* at 173–74.
[55] *Id.* at 176.
[56] *Id.* at 177.

proposes a range of 770 to 900 lb CO_2/MWh, depending on the specific base load rating.[57] EPA asks for comments on these proposed standards and whether any other new technologies should be incorporated into a standard.[58]

Phases 2 and 3

For the subsequent phases, EPA proposes CCS and hydrogen co-firing compliance pathways and would allow project developers to select either option. EPA explains that there may be more than one viable pathway to significantly reduce CO_2 emissions and EPA sees value in enabling project developers to select the best path.[59]

EPA requests comment on the proposed compliance dates for each pathway.[60] EPA also seeks comment on whether the agency should finalize both pathways as separate subcategories with separate standards of performance, or whether it should finalize one pathway with the option of meeting the standard of performance using either system of emission reduction (e.g., 90 percent CCS or 96 percent low-GHG hydrogen).[61]

CCS Pathway

The proposed second phase for base load resources that are adopting CCS would require operators to meet a performance standard of 90 lb CO_2/MWh-gross by 2035, which is based on installation of CCS with 90 percent capture. EPA states that CCS has been adequately demonstrated at coal-fired plants, industrial sources, and combustion turbines.[62] EPA explains that a 90 percent capture rate is reasonable because sources can capture at a higher percentage at certain times to offset times of lower capture.[63] However, EPA requests comment on the range of capture rates from 90 to 95 percent or greater and the range of feasible emissions reductions.[64]

CCS is Adequately Demonstrated: To support its conclusion that CCS on combustion turbines is adequately demonstrated, EPA cites examples of demonstrated projects and companies' announcements regarding their plans to install CCS on natural gas combined cycle units (NGCCs), constructed CO_2 transport pipelines, and geologic sequestration sites.

[57] *Id.* at 19.
[58] *Id.* at 179; see also the *Efficient Generation and Combustion Turbine Electric Generating Units* TSD.
[59] Proposed Rule at 166–67.
[60] *Id.* at 243.
[61] *Id.* at 244.
[62] *Id.* at 194.
[63] *Id.* at 192.
[64] *Id.* at 193.

To justify that CCS technology on combined cycle EGUs is adequately demonstrated, EPA includes the following examples:

- The Bellingham Energy Center's 40 MW slipstream food industry capture facility in Massachusetts that operated from 1991 to 2005, capturing 86 to 95 percent of the CO_2;[65]
- The proposed 900 MW Peterhead Power Station NGCC in Scotland that will be able to capture 90 percent of the CO_2, and is projected to be operational by 2030;[66] and
- An announced 1,800 MW NGCC in West Virginia that will use CCS and will "begin operation later this decade."[67]

EPA states that its conclusion that CCS is adequately demonstrated is further corroborated by the grants, loan guarantees, and federal tax credits to support CO_2 capture projects.[68]

In its discussion regarding whether the infrastructure needed to support such projects is adequately demonstrated, EPA explains that pipeline transport of CO_2 has been occurring for nearly 60 years and that the CO_2 pipeline network has steadily expanded.[69] According to the Pipeline and Hazardous Materials Safety Administration (PHMSA), "5,339 miles of CO_2 pipelines were in operation in 2021, a 13 percent increase in CO_2 pipeline miles since 2011."[70] EPA provides examples of projects that recently announced CO_2 pipeline expansions, including the Midwest Carbon Express, which would "add more than 2,000 of dedicated CO2 pipeline in Iowa, Nebraska, North Dakota, South Dakota, and Minnesota."[71] EPA also notes that the IIJA supports CO_2 transport infrastructure.

EPA explains that as described in the 2015 NSPS, new gas plants have more flexibility than existing plants to construct EGUs near existing or planned pipelines and geologic sequestration and can build transmission lines to deliver electricity to consumers.[72] In its discussion about proposed timing for states to submit plans regulating existing gas plants, EPA estimates that the "design and implementation of CO_2 transport and storage can be completed within 5 years."[73] This includes site characterization, pipeline feasibility and design activities, permitting, engineering, and construction.[74] EPA notes that when looking at the CCS control technology from a nationwide basis, this pathway raises questions about the availability of CO_2 transport and sequestration infrastructure and the lead time required to build such infrastructure and requests comments on the appropriate compliance date between 2030 and 2035.[75]

EPA also provides existing project examples to show that geologic sequestration is adequately demonstrated. These include natural features such as the Jackson Dome, in Mississippi, which has trapped CO_2 for more than 65 million years, and the Great Plains Synfuel Plant saline capture facility that captures 2

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[65] *Id.* at 199.
[66] *Id.* at 199.
[67] *Id.* at 200.
[68] *Id.* at 201.
[69] *Id.* at 204.
[70] *Id.* at 204–05.
[71] *Id.* at 205.
[72] *Id.*
[73] *Id.* at 499.
[74] *Id.* at 500.
[75] *Id.* at 242.

million metric tons of CO_2 per year, and is used for enhanced oil recovery.[76] EPA states that DOE and the US Geological Survey have conducted a preliminary analysis of geologic sequestration resources in the US, and found that "[n]early every state in the U.S. has or is in close proximity to formations with geologic sequestration potential."[77] EPA describes the regulatory oversight of secure geologic sequestration, including through the Underground Injection Control Program under the Safe Drinking Water Act and the GHG Reporting Program under the CAA, which requires monitoring and reporting for CO_2 capture, underground injection, and geologic sequestration.[78]

CCS Costs: EPA states that 90 percent CCS can be implemented at a reasonable cost when incorporating the 45Q tax credits.[79] EPA considers capture costs, CO_2 transport and sequestration costs, and the section 45Q tax credit. EPA assumes that "investors maximize the value of IRC section 45Q tax credit at $85/metric ton" by meeting the prevailing wage and apprenticeship requirements of section 45Q(h)(3)–(4).[80]

EPA states that it is reasonable to take into account the 45Q tax credit when considering the cost of CCS because "the legislative history of the IRA makes clear that Congress was well aware that the EPA may promulgate rulemaking under CAA section 111 based on CCS and explicitly stated that the EPA should consider the tax credit to reduce the costs of [CCS]."[81] In addition, in the 2015 NSPS, EPA recognized that the section 45Q tax credit or other tax incentives could factor into the costs when determining partial CCS to be the BSER.[82]

To calculate total costs, EPA assumed a 30-year useful life and accounted for the 12-year tax credit provided by 45Q. EPA finds that the CCS costs range from $6 to $15/MWh or $19 to $44/ton of CO_2 reduced, depending on the amortization period.[83]

To determine the reasonableness of these controls, EPA compares these costs to the cost of controls at EGUs for other air pollutants and the costs of GHG controls in other industries.[84] For example, EPA notes that in the 2011 Cross-State Air Pollution Rule, it projected the costs to install and operate wet flue gas desulfurization on existing coal EGUs to be $14.80 to $18.50/MWh, which it concluded were reasonable. EPA also notes that in the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category, EPA found that $98/ton of carbon dioxide equivalent (CO_{2e}) to be a reasonable cost for reducing methane emissions.[85]

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[76] *Id.* at 209–10.
[77] *Id.* at 217.
[78] *Id.* at 214.
[79] *Id.* at 222.
[80] *Id.* at 230–31.
[81] *Id.* at 229.
[82] *Id.*
[83] *Id.* at 234.
[84] *Id.*
[85] *Id.*

***CCS Non-air Quality Health and Environmental Impact and Energy Requirements*:** For energy requirements, EPA states that installation and operation of CCS control technology alone does not impact the unit's potential-to-emit criteria or hazardous air pollutants.[86]

EPA states that including CCS technology that captures 90 percent or more CO_2 will reduce net output, which may lead units to scale larger and could have the potential to increase non-GHG air emissions.[87] EPA states, however, that this pollution should be abated by requirements in other CAA rules, such as the National Emission Standards for Hazardous Air Pollutants (NESHAP) which may require new sources to install an oxidation catalyst to limit formaldehyde emissions for new sources and SCRs for EGUs subject to major source New Source Review requirements.[88]

EPA explains that stakeholders have expressed concerns about the safety and other potential impacts of CCS projects on proximate or overburdened communities, but for the reasons noted above, it does not expect CCS on new combustion turbines to result in substantial increases in emissions of non-GHG air pollutants.[89] See more detail on stakeholder concerns regarding use of CCS in the Environmental Justice and Stakeholder Engagement section below.

Hydrogen Co-Firing Pathway

Under the proposed second phase for intermediate and base load resources, facilities that are adopting low-GHG hydrogen co-firing would need to meet the following standards by 2032:

- Intermediate load resources: 1,000 lb CO_2/MWh-gross, which is based on highly efficient simple cycle technology coupled with co-firing 30 percent (by volume) low-GHG hydrogen, and
- Base load resources: 680 lb CO_2/MWh-gross, which is based on highly efficient combined cycle technology coupled with co-firing 40 percent (by volume) low-GHG hydrogen.

For base load resources, EPA proposes a third phase performance standard of 90 lb CO_2/MWh-gross by 2038, which is based on co-firing 96 percent low-GHG hydrogen. For intermediate load, EPA asks whether such EGUs should be subject to a third phase standard based on 96 percent low-GHG hydrogen co-firing by 2038.[90]

Hydrogen is Adequately Demonstrated: To support its conclusion that hydrogen co-firing is adequately demonstrated, EPA states that gas plants have co-fired small blends of up to 10 percent hydrogen without modification, and several power producers are developing hydrogen co-firing projects.[91] Examples cited by EPA include:

- The Intermountain Power Agency project in Utah began planning to co-fire with hydrogen even before the IRA passed and made the project more economical. This project has begun transitioning the 1,800-MW coal-fired EGU to an 840-MW NGCC that will co-fire with 90 percent low-GHG hydrogen

[86] *Id.*
[87] *Id.* at 235.
[88] *Id.* at 236.
[89] *Id.* at 237.
[90] *Id.* at 185.
[91] *Id.* at 247–48.

(via solar powered electrolysis with geologic storage) upon startup in 2025 and combust 100 percent hydrogen by 2045.[92]

- The 484 MW combined cycle combustion turbine Long Ridge Energy Generation Project in Ohio began operations in 2021 and "is designed to transition to 100 percent hydrogen in the future."[93]

EPA also states that several currently available turbine designs can burn up to 75 percent hydrogen and multiple vendors have indicated that they intend to produce turbines that fire 100 percent hydrogen in the 2030s.[94] EPA states that because "the cost of natural gas is lower than the cost of hydrogen, most new combustion turbines are not, at the present time, designed to burn 100 percent hydrogen when they are placed into service."[95]

However, EPA requests comment on whether new gas plants will be able to combust higher levels of hydrogen, which would support expediting the compliance date of the second phase (i.e., 50 percent by 2030).[96] To support third phase standard based on 96 percent low-GHG hydrogen co-firing by 2038, EPA cites to multiple projects that have announced plans to co-fire with 100 percent hydrogen in the 2030s, including the Intermountain Power Agency project.[97]

EPA notes that access to low-GHG hydrogen is an important factor but given the growth in the hydrogen production sector, EPA believes the phase 2 and 3 compliance deadlines are achievable.[98] EPA states that federal incentives, including the IRA's 45V tax credit, are "anticipated to significantly increase the availability of low-GHG hydrogen by 2032" and that these programs have prompted development of new low-GHG projects, as evidenced by 374 new projects announced as of August 2022, representing a 21 percent increase over current annual low-GHG hydrogen output.[99] EPA also states that the industrial and transportation sectors are creating a demand for hydrogen production and the IRA's 45V tax credit has the potential to drive significant production of electrolytic hydrogen.[100] EPA solicits comment on whether affordable low-GHG hydrogen will be available by 2030 and whether that availability supports moving forward the compliance date or increasing the percent of hydrogen co-firing.[101]

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[92] *Id.* at 248.
[93] *Id.*
[94] *Id.* at 258–59.
[95] *Id.* at 258.
[96] *Id.*
[97] I*d.* at 259.
[98] *Id.* at 261–62.
[99] *Id.* at 275.
[100] *Id.* at 262–63.
[101] *Id.* at 264.

EPA also states that an important feature of hydrogen is the GHG emissions generated during production, depending on the method.[102] EPA notes that more than 95 percent of dedicated hydrogen is currently produced from natural gas using steam methane reforming (SMR). Co-firing hydrogen derived from SMR without CCS will result in more net GHG emissions than simply burning natural gas.[103] EPA therefore "proposes to conclude that cofiring with low-GHG hydrogen (but not other forms of hydrogen) appropriately considers the statutory factors and constitutes the 'best' system of emission reduction."[104]

EPA draws from the IIJA and IRA to support its proposed low-GHG hydrogen definition.[105] Based on the highest tier of the 45V(b)(2) tax credit—which awards the highest amount of tax credit for hydrogen production with the lowest emissions—EPA defines low-GHG hydrogen as hydrogen that "is produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen (kg CO_2e/kg H2) on a well-to-gate basis consistent with the system boundary established in IRC section 45V."[106] This definition would include hydrogen produced by electrolysis (splitting water into hydrogen and oxygen) using non-emitting energy resources (solar, wind, nuclear, and hydroelectric power).[107]

EPA is soliciting comment on this definition of low-GHG hydrogen, whether it is necessary to provide a specific definition of low-GHG hydrogen in the rule,[108] and whether the low-GHG hydrogen requirement could be treated as severable from the rule.[109]

EPA states that co-firing hydrogen at the source "plainly qualifies as a 'system of emission reduction'."[110] EPA finds support in *West Virginia v. EPA*, where the Court noted with approval that EPA has found "fuel-switching" as one of the "more traditional air pollution measures."[111] EPA states that it has relied on lower-emitting fuels to set BSER in several CAA section 111 rules, including its 1979 and 2007 NSPS for steam-fired EGUs that require use of coal washing to remove sulfur to reduce sulfur emissions.[112] EPA explains that even if BSER is limited to controls that can be applied at and to the source, as the ACE rule required. EPA contrasts this approach with co-firing biomass in place of fossil fuel, which the ACE rule rejected because it relied on upstream GHG accounting. By comparison, "co-firing with hydrogen in place of natural gas at a combustion turbine achieves emission reductions at the source."[113]

EPA rejects BSER that includes hydrogen produced with higher-emitting fuels. In *Portland Cement Ass'n v. Ruckelshaus*, the D.C. Circuit held that "[t]he standard of the 'best system' is comprehensive, and we cannot imagine that Congress intended that 'best' could apply to a system which did more damage to water than it

[102] *Id.*
[103] *Id.* at 254.
[104] *Id.* at 264.
[105] *Id.*
[106] *Id.* at 244–45.
[107] *Id.* at 245.
[108] *Id.* at 268.
[109] *Id.* at 290.
[110] *Id.* at 286.
[111] *Id.* at 285.
[112] *Id.*
[113] *Id.* at 285–86, FN 465.

prevented to air."[114] As applied here, EPA found that it must consider the GHG emissions upstream of the co-firing, and therefore, could not conclude that high-emission hydrogen meets the statute's standards.

Hydrogen Costs: EPA explains that the primary cost for such projects relates to the cost of hydrogen relative to natural gas. However, EPA notes that DOE has established a goal of reducing the cost of low-GHG hydrogen production to $1/kg by 2030, before any IRA incentives, which would increase the levelized cost of electricity (LCOE) by $2.9/MWh for a gas plant firing with 30 percent hydrogen at a 65 percent capacity factor.[115] EPA also states that incorporating the IRA tax credits may result in cost parity with natural gas.[116]

Hydrogen Non-air Quality Health and Environmental Impact and Energy Requirements: EPA states that co-firing hydrogen in gas plants would result in additional NOx emissions, but those can be controlled by NOx combustion controls through dry low NOx (DLN) combustion.[117] EPA explains that the ability to use DLN combustors in combustion turbines is currently limited but that "all major combustion turbine manufacturers have developed DLN combustors for utility EGUs that can co-fire hydrogen," and "the major combustion turbine manufacturers are designing combustion turbines that will be capable of combusting 100 percent hydrogen by 2030, with DLN designs that assure acceptable levels of NOx emissions."[118] For these reasons, EPA concludes that its proposed BSER would not have adverse non-air quality health and environmental impacts.

Existing Gas Plants

EPA proposes to regulate only large existing base load combustion turbines that have the highest GHG emissions and for which CCS is likely to be most cost effective.[119] EPA recognizes that the existing gas fleet is large, plays a key grid reliability role, and that there is a significant lead time required to develop CCS and hydrogen-related infrastructure. Therefore, it focuses only on units greater than 300 MW with an annual capacity factor of at least 50 percent.[120] EPA estimates that "37 GW of capacity would meet these criteria in 2035, representing 14 percent of the projected existing combustion turbine capacity and 23 percent of the projected generation capacity from existing combustion turbines in 2035."[121] However, EPA asks for comments on the appropriate scope (by size and capacity factor) that should be included in this rulemaking, including the agency's assumptions about future operation of combustion turbines coupled with the availability of CCS and hydrogen-related infrastructure.[122]

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114 *Id.* at 287–88.
115 *Id.* at 281.
116 *Id.* at 282.
117 *Id.* at 282 & 272.
118 *Id.* at 273.
119 *Id.* at 457–58.
120 EPA proposes to include heat recovery output in the calculation of net energy output. *See* EPA's proposed definition for a stationary combustion turbine: "all equipment including, but not limited to, the . . . heat recovery system, . . . [and] any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment." Proposed Emission Guidelines, Subpart UUUUb at 21; *see also* EPA's proposed equation for calculating affected EGU net energy output. *Id.* at 15.
121 *Id.* at 460.
122 EPA explains: "More specifically, the EPA is requesting comment on how to consider the rate of CCS (and potentially hydrogen) infrastructure development in determining a BSER that could potentially impact hundreds of sources. If, for instance, increased renewable generation and storage capacity were to lead to a smaller number

For these base load units, BSER would be based on installing and operating 90 percent CCS by 2035 or blending with 30 percent low-GHG hydrogen by 2032 and 96 percent by 2038. These standards are consistent with BSER for new gas plants. EPA explains that it is important to stagger CCS compliance deadlines for existing coal units (discussed above) and combustion turbines. EPA states that because coal plants emit more CO_2, EPA is proposing to first require CCS installation on coal units to stagger the demand for CCS installations while still allowing for time to take advantage of the 45V and 45Q tax credits.[123] EPA cites to other section 111(d) rules that incorporate lead time to accommodate installation of the control technology, including its 2005 rules establishing emission guidelines for electric utility steam generating units, "with a 13-year compliance timeframe for a second control phase".[124]

EPA also cites power sector modeling to explain its focus on regulating existing base load combustion turbines. EPA explains that when it modeled this proposed rule without any requirement for existing gas plants, electricity production shifted from the regulated categories to existing gas plants, increasing GHG emissions by about eight percent.[125] EPA also notes that incorporating the effects of the IRA, gas-fired generation is projected to fall from 2030 to 2045 through "primarily . . . declining capacity factors[,] not through retirements."[126] EPA requests comment on how its projected future use of NGCCs should inform BSER, including EPA's assumptions regarding "the speed at which new low-emitting generation will come on-line and the impact that it has on likely capacity factors for combined cycle units (in particular the projection that capacity factors will grow in the 2028/30 timeframe but decrease in later years)."[127]

EPA intends to address emissions from the remaining combustion turbines in a separate rulemaking.[128] In anticipation of that rulemaking, EPA asks for information on the appropriate BSER for the remaining base load units and a BSER for intermediate load similar to BSER for new gas plants. EPA also requests comments on the "potential changes in operational patterns for turbines, particularly as more renewables and storage enter the grid."[129]

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of units operating at capacity factors of greater than 50 percent, the proposed BSER would not affect as many units and a smaller size threshold might be possible without expanding the amount of infrastructure needed. Conversely, if more units were likely to operate at a higher capacity factor, a higher capacity threshold might be appropriate. If the number of units likely to be covered by a 50 percent threshold were sufficiently small, it might be reasonable to include units in the intermediate category (e.g., units with capacity factors of between 20 percent and 50 percent) in a first rulemaking addressing the existing fossil fuel-fired turbine category." *Id*. at 491–92. In addition, EPA seeks comment on setting a threshold of 100 to 200 MW and a 40 percent capacity factor. *Id.* at 482.

[123] *Id.* at 459.

[124] EPA includes the following additional examples: "61 FR 9905, 9919 (March 12, 1996) (establishing emission guidelines for municipal solid waste landfills, with a 2.5-year compliance timeframe); 62 FR 48348, 48381 (September 15, 1997) (establishing emission guidelines for hospital/medical/infectious waste incinerators, with up to 3 years after state plan approval for facilities to install control equipment)." *Id.* at 461.

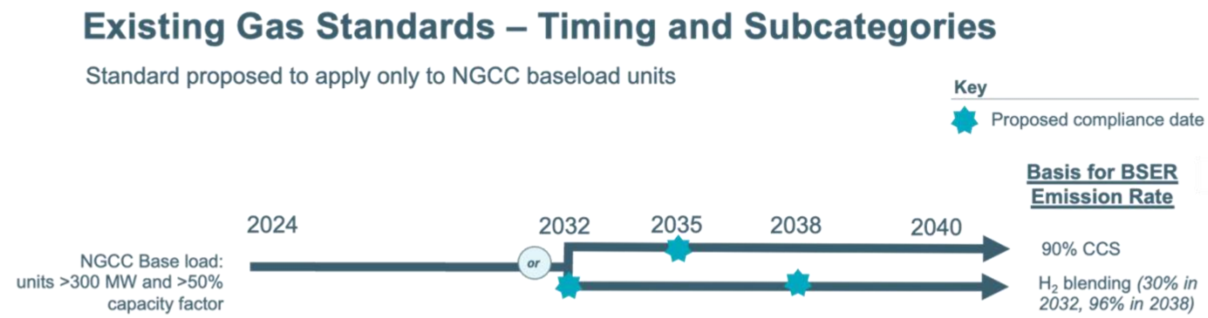
[125] *Id.* at 461–62.

[126] *Id.* at 462.

[127] *Id.* at 491.

[128] "Because the second segment would include both smaller more frequently used units and less frequently used units, in that action, the EPA anticipates considering a broader range of technologies including heat rate improvements." *Id.* at 463, 493.

[129] *Id.* at 494.



Existing Gas Plants – Adequately Demonstrated: EPA cites examples of projects to demonstrate existing turbines are capable of co-firing including the Long Ridge Energy Terminal's 485-MW NGCC, which tested 5 percent hydrogen co-firing in 2022 and is designed to transition to 100 percent hydrogen fuel.[130] EPA also cites to companies that are exploring use of hydrogen in their existing fleet, including Constellation Energy, which stated in comments in response to a 2022 EPA white paper that "[b]ased on our assessments, retrofits using available technology can allow hydrogen blending at 50-100 percent by volume in select generators."[131]

EPA provides similar justifications described as part of the new gas proposal to conclude that it is reasonable to expect adequate low-GHG hydrogen to be available in the 2032 and 2038 timeframe. Similar to EPA's questions regarding the proposed standards for new gas plants, EPA requests comment on the feasibility of the proposed BSER for existing gas plants, whether BSER should be a single pathway, and whether compliance should begin earlier (e.g., 2030).[132]

State Plans

In December 2022, EPA proposed revised CAA section 111(d) implementing regulations, which apply to all section 111 rulemakings unless modified by source-specific requirements. EPA states it intends to finalize the rule before publishing the final emission guidelines for existing coal and gas plants. However, EPA is proposing some differences from the December proposal that would apply to power plants.

Timing

EPA states that it expects to publish final emission guidelines in June 2024 and proposes to require states to submit their implementing plans 24 months later.[133] EPA requests comment on whether the state submission deadline provides sufficient time to permit and build any necessary controls to meet the proposed BSER compliance deadlines.

EPA proposes certain legally enforceable requirements to ensure progress toward compliance. EPA explains that for the power sector emission guidelines, EPA proposes appropriate "pre-compliance date, federally enforceable requirements associated with the planning, construction, and operation of natural gas or

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[130] *Id.* at 469.
[131] *Id.* at 470.
[132] *Id.* at 460.
[133] *Id.* at 501.

hydrogen co-firing infrastructure and CCS as increments of progress."[134] EPA proposes to adopt emission guideline-specific implementation of the five generic increments specified in the 111(d) implementing regulations, and additional increments for certain subcategories.[135] EPA proposes to require states to assign calendar-date deadlines for each increment.[136] EPA requests comment on this approach and asks whether EPA should set specific deadlines or provide states such discretion.

Remaining Useful Life and Other Factors

CAA section 111(d)(1) allows states to "take into consideration, among other factors, the remaining useful life of the existing sources to which the standard applies."[137] EPA states that it intends for the December 2022 proposal for remaining useful life and other factors (RULOF) provisions to apply to power plants.[138] EPA discusses how its proposed RULOF requirements would apply to state plans under the emission guidelines.[139] For example, EPA explains that in determining whether to invoke RULOF based on unreasonable cost, states should consider the same metrics that EPA assessed for BSER ($/ton CO_2 reduced and increases in LCOE).[140] EPA proposes that only costs that are outliers "e.g., that are greater than the 95th percentile of costs on a fleetwide basis" or are costs that EPA found unreasonable under the emission guidelines "would likely represent a valid demonstration of a fundamental difference and could be the basis of invoking RULOF."[141] EPA requests comment on how the December 2022 provisions should be implemented for proposed existing coal and existing gas EGU emission guidelines.[142]

Compliance Flexibilities: Trading and Averaging

To provide compliance flexibility, EPA proposes to allow trading and averaging consistent with the proposed 111(d) implementing regulations.[143] EPA explains that states may incorporate such flexibilities provided that implementation "will result in a level of emission performance by the affected EGUs that is equivalent to each source individually achieving its standard of performance."[144] EPA acknowledges that the unique characteristics of the subcategories may require certain limitations placed on such flexibilities and discusses those considerations. For example, EPA states that it would not be appropriate to allow trading for certain affected EGUs under subcategories that are designed to provide the same operational flexibilities as trading, such as imminent-term and near-term coal units.[145]

EPA also describes how states could establish a mass-based trading program as part of a state plan. EPA notes that mass-based emission trading has been used in the power sector for nearly three decades but past experience "shows that emission budgets have often been overestimated when set many years in advance of the start of a program, as economic and technological conditions have changed significantly

[134] *Id.* at 559.
[135] *Id.* at 560.
[136] *Id.* at 562.
[137] *Id.* at 534.
[138] *Id.*
[139] *Id.* at 535.
[140] *Id.* at 537.
[141] *Id.* at 539–40.
[142] *Id.* at 545.
[143] *Id.* at 575.
[144] *Id.*
[145] *Id.* at 581.

between the time the program was adopted and when compliance obligations begin."[146] To limit this issue and possibility, EPA recommends states consider dynamic budgeting, as applied in the Good Neighbor Plan.[147] EPA is seeking comment on whether the method of mass-based trading using dynamic budgeting is appropriate and whether mass-based emission trading programs could be designed to ensure equivalency with the applicable BSER.[148]

EPA also requests comment on whether state plans should allow for banking of compliance instruments, in which "permitting allowances that remain unused in one control period to be carried over for use in future control periods."[149] EPA expresses concern that unrestricted banking between control periods may result in allowance surpluses, which could undermine the trading program's goal of ensuring equivalency with BSER.[150] EPA solicits comment on whether it should allow banking and program designs that would be necessary to accommodate banking.[151]

EPA also requests comment on "whether certain types of averaging and trading maintain the stringency of the EPA's BSER."[152] EPA solicits comment about other possible compliance flexibilities as well, for example a "dual-pathway" option that would allow units to opt into two different subcategories in a state plan, meet all applicable requirements for both pathways, and then make a decision about its final subcategory by a certain date.[153]

Environmental Justice and Stakeholder Engagement

Under Executive Order 12898, federal agencies must identify and address disproportionate and adverse human health or environmental effects of their programs, policies, and activities on minority and low-income populations.[154] Executive Order 13875 requires federal agencies to assess to what extent their programs and policies perpetuate systemic barriers to opportunities and benefits for people of color and other underserved groups.[155]

In the proposal and accompanying regulatory impact analysis, EPA includes a quantitative environmental justice assessment of the proposal's potential effects on communities' exposure to non-GHG pollutants, specifically ozone and particulate matter (PM2.5). The proposal describes the qualitative effects of climate change on communities with environmental justice concerns, assesses the demographics of populations

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[146] *Id.* at 586.
[147] *Id.* at 586–87.
[148] *Id.* at 588
[149] *Id.* at 589.
[150] *Id.*
[151] *Id.* at 590.
[152] *Id.* at 575–76.
[153] *Id.* pp. 624–625.
[154] Under Executive Order 12,898, issued on Feb. 11, 1994, agencies must "identify[] and address[], as appropriate, disproportionately high and adverse" effects. President Biden recently amended Order 12898 to require agencies to "identify, analyze, and address disproportionate and adverse environmental and human health effects . . . including those related to climate change and cumulative impacts of environmental and other burdens," among other changes. Executive Order 14,096 (Apr. 21, 2023). EPA sent the proposal to the Office of Information and Regulatory Affairs (OIRA) for review on March 15, 2023, prior to the issuance of Order 14,096.
[155] Executive Order 13,985 (Jan. 20, 2021).

within 10 and 50 km of existing coal-fired EGUs, and includes state-specific pollutant concentration reductions by demographic for the contiguous US.[156] In the following we summarize EPA's responses to CCS and hydrogen-related concerns, and EPA's quantitative non-GHG air pollutant impact assessment.

EPA explains that it conducted multiple stakeholder engagement processes before issuing the proposal, including opening a pre-proposal non-rulemaking docket to solicit written feedback[157] and holding two rounds of outreach to specific stakeholders including environmental justice and community organizations.[158]

EPA invites public comment on "all aspects of its proposed determination that CCS represents the BSER for certain new and existing fossil fuel-fired EGUs, including its evaluation of the various regulatory frameworks that apply to CCS."[159] In addition to accepting written comments for 60 days after the proposal is published in the Federal Register, EPA will hold virtual public trainings for communities and tribes on June 6 and 7 about the proposal and how to participate in the public comment process. For more information, including EPA's EJ-specific fact sheet, visit EPA's website here.

Response to Community Concerns Regarding CCS and Hydrogen

The proposal responds to three stakeholder concerns: (1) that CCS and hydrogen technologies will extend the life of EGUs that have historically overburdened communities, (2) the safety of those EGUs and the control technology, and (3) community engagement for communities potentially impacted by EGUs installing these control technologies.

Extending the Operation of Coal-fired EGUs and Other Units: The first concern is that adding CCS to EGUs[160] will extend the life of existing coal-fired EGUs, subjecting overburdened communities to additional pollution. In response, EPA states that "CCS is the most effective add-on pollution control available for mitigation of GHG emissions from affected sources", and notes that installing CCS may improve EGUs' control of sulfur dioxide (SO_2).[161] EPA notes that CCS-related retrofits may trigger requirements under the major source New Source Review (NSR) program, also under the CAA, which will include opportunities for the public to comment on what additional non-GHG pollution controls should be required at these facilities.[162] (For more on the NSR program, see EELP's Regulatory Tracker page here.)

Stakeholders expressed similar concerns about the potential for EPA's reliance on hydrogen to satisfy BSER for certain units to increase fossil-derived hydrogen production, which could extend the life of petrochemical industries that already pollute in vulnerable communities.[163] Notably, the proposed BSER for new gas and

[156] The state-specific PM2.5 analysis begins on p. 6-17 of the Regulatory Impact Analysis, and the state-specific ozone analysis begins on p. 6-25.
[157] Docket ID No. EPA-HQ-OAR-2022-0723.
[158] Proposed Rule at 141.
[159] *Id.* at 31.
[160] Under the proposal, CCS is a component of BSER for new base load stationary combustion turbines (i.e., new gas-fired plants), existing coal-fired plants that plan to operate after 2040, and large and frequently operated existing combustion turbine EGUs (i.e., large, existing gas-fired plants used for base load power). *Id*. at 655.
[161] *Id.* at 655–656.
[162] *Id.* at 656.
[163] EPA notes that this was a "primary concern" expressed during the February 27th National Tribal Energy Roundtable Webinar. *Id.* at 658.

large base load existing gas plants includes only "low-GHG hydrogen." EPA proposes to define low-GHG hydrogen as hydrogen that is produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen (kg CO_2e/kg H2). EPA is accepting comment on this proposed definition. For more details, see our summary earlier in this paper on Proposed Standards for Existing Gas Plants.

EPA also notes that new combustion turbines that co-fire with hydrogen may also trigger major source NSR program requirements. However, facilities may avoid triggering NSR under two scenarios: (1) the turbine is proposed at an existing facility, and the net emissions for the facility decrease (e.g., if the turbine replaces an existing coal-fired EGU, and the facility has emission reduction credits from the shutdown unit), or (2) emissions from the new unit are below the thresholds to trigger major source NSR.[164] EPA also notes that "since hydrogen is non-toxic, and it does not produce carbon dioxide when burned, the inclusion of hydrogen in combustion turbine operations will lower overall health risks compared with hydrocarbons."[165]

Safety: The second CCS-related concern is regarding CO_2 pipeline safety and geologic sequestration. EPA notes that the Pipeline and Hazardous Materials Safety Administration (PHSMA) within the Department of Transportation (DOT) regulates supercritical CO_2 pipelines, and that PHMSA plans to initiate a rulemaking soon to update standards for those pipelines.[166]

Regarding geologic sequestration, EPA regulates these processes through the Underground Injection Control (UIC) Program under the Safe Drinking Water Act (SDWA), and through the Greenhouse Gas Reporting Program (GHGRP) under the CAA. EPA states that its UIC Class VI regulations "include strong protections for communities to prevent contamination of underground sources of drinking water" including "strict construction, operating, and monitoring requirements to ensure well and formation integrity, proper plugging of wells, and long-term project management and post-injection site care to ensure leakage prevention."[167] EPA commits to following the regulatory framework for CCS set out by the Council on Environmental Quality (CEQ).[168]

EPA reiterates that states and tribes applying for Class VI primacy enforcement authority (i.e., primacy) should "implement[] an inclusive public participation process, consider[] environmental justice impacts on communities" and incorporate other mitigation measures.[169] Relatedly, EPA is currently accepting comments **until July 3** on a proposal to give Louisiana's Department of Natural Resources (LDNR) authority to issue UIC permits for geologic carbon sequestration facilities within the state, excluding Indian lands. Currently only North Dakota and Wyoming have Class VI primacy.[170]

[164] *Id.*
[165] *Id.*
[166] *Id.* at 656.
[167] *Id.* at 657.
[168] Carbon Capture, Utilization, and Sequestration Guidance, 87 Fed. Reg. 8,808 (Feb. 16, 2022).
[169] Proposed Rule at 215. *See also*, *Letter from Administrator Regan to US State Governors*, EPA (Dec. 9, 2022).
[170] *Primary Enforcement Authority for the Underground Injection Control Program*, EPA (last updated May 17, 2023).

Community Engagement: The third CCS-related concern is that communities will not have a meaningful opportunity to inform the development of CCS projects that will affect them. In response, EPA makes clear the obligation of states, consistent with EPA's proposed CAA 111(d) implementing regulations, to provide for "meaningful engagement" as part of the state plans for existing coal plants and existing natural gas plants: "state plans should specifically ensure that community members have an opportunity to share their input if they reside near a fossil fuel-fired steam generating unit that plans to install CCS to meet the requirements of these proposed rules regarding how to responsibly deploy this technology."[171]

Quantitative Demographic Analysis of Ozone and PM2.5 Exposures

Consistent with Executive Order 12898, EPA conducted a quantitative analysis of potential EJ concerns related to changes in exposure to non-GHG air pollutants. Specifically, EPA modeled average and distributional exposures to ozone and PM2.5 across the contiguous US following implementation of the proposal in 2028, 2030, 2035, and 2040. EPA states that this nationwide modeling is appropriate because EGUs "typically have tall stacks that result in emissions from these sources being dispersed over large distances, and [] both ozone and PM2.5 can undergo long-range transport."[172] Furthermore, "[b]ecause the pollution impacts that are the focus of these rules may occur downwind from affected facilities, ozone and PM2.5 exposure analyses that evaluate demographic variables are better able to evaluate any potentially disproportionate pollution impacts of these rulemakings [as compared to EPA's proximity analysis]."[173]

To assess potential EJ concerns[174] associated with the proposal, EPA relies on the following three-question framework in the agency's June 2016 EJ Technical Guidance[175]:

1. Are there potential EJ concerns associated with stressors affected by the regulatory actions for population groups of concern in the baseline?
2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
3. For the regulatory option(s) under consideration, are potential EJ concerns created [, exacerbated,] or mitigated compared to the baseline?[176]

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[171] Proposed Rule at 657.
[172] *Id.* at 6-11. EPA specifically evaluates warm season maximum daily eight-hour ozone average concentrations and average annual PM2.5 concentrations. EPA does not assess exposure to other metrics, including shorter-term exposures to ozone and PM2.5. *Id.* at 6-12.
[173] Proposed Rule at 653.
[174] EPA guidance states that a "regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples through the action under development." Regulatory Impact Analysis at 6-2; *Guidance on Considering Environmental Justice During the Development of Regulatory Actions*, EPA 10 (May 2015).
[175] *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis*, EPA (June 2016).
[176] Regulatory Impact Analysis at 6-4 (addition in original). EPA later paraphrases this third question as asking whether EJ concerns are "exacerbated, unchanged, or mitigated" by the proposal. *Id.* at 6-11. The addition of "unchanged" is significant because it suggests EPA should assess potential EJ concerns even if the proposed action would maintain the existing standard. The other recent example of EPA including "unchanged" in the third

After modeling the proposal's effect on ozone and PM2.5 exposures from coal-fired EGUs, EPA concludes that as a baseline, "there are disparities across various populations" for both pollutants. EPA states that under EJ question 1, these disparities are present for "Hispanics, Asians, those linguistically isolated, and those less educated," with Black populations experiencing disproportionately higher PM2.5 concentrations. EPA also finds that under EJ question 2, "these disparities are likely to persist" after the proposed rule is finalized. EPA concludes that the proposed rule is "unlikely to mitigate or exacerbate PM2.5 exposures disparities." Regarding ozone exposures, "while most snapshot years . . . will not likely mitigate or exacerbate ozone exposure disparities," ozone exposure disparities may be exacerbated for some population groups in 2030. However, with respect to EJ question 3, EPA believes this effect "is likely modest" given the small magnitude of changes in ozone concentrations relative to baseline disparities. EPA adds, "[i]mportantly, the [proposal] is expected to lower PM2.5 and ozone in many areas, and thus mitigate some pre-existing health risks of air pollution across all populations evaluated."[177]

EPA notes that overall, "[i]n 2030 alone, the health benefits of the proposals on new gas and existing coal include approximately 1,300 avoided premature deaths; more than 800 avoided hospital and emergency room visits; approximately 2,000 avoided cases of asthma onset; more than 300,000 avoided cases of asthma symptoms; 38,000 avoided school absence days; and 66,000 lost work days."[178]

Climate, Health, and Grid Impacts

EPA projects that the proposal would result in significant monetized climate and health benefits. EPA explains that these estimates do not include the impact of the proposed standards for existing gas plants or for the third phase of the new gas plants.[179] EPA estimates that the proposal's present value net climate and health benefits between 2024 to 2043, using a 3 percent discount rate, are $98 billion in 2019 dollars.[180] For more on the potential health impacts of the proposal, see our Environmental Justice and Stakeholder Engagement summary previous to this section.

EPA's regulatory impact analysis discusses projected changes to the US electric generation fleet under EPA's projected baseline, which included the IRA tax credits, and under the proposed rule, but did not reflect the proposed standards for existing gas plants or for the third phase of the new gas plants.[181]

prong of its EJ analysis is the Regulatory Impact Analysis supporting the proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, EPA 6-10 (Apr. 2023) (asking whether potential EJ concerns in the baseline are "exacerbated, unchanged, or mitigated").

[177] Proposed Rule at 654–55. Specifically, EPA estimates that at least 75 percent of the U.S. population is predicted to experience air quality improvements (or a lack of change) for PM2.5 under all policy scenarios analyzed except for the 2028 more stringent regulatory option, in which approximately 54 percent of the U.S. population is predicted to experience a PM2.5 air quality improvement. In contrast, 50-97 percent of the U.S. population is predicted to experience ozone improvements (or lack of change) due to the proposed rulemakings and the other 3-50 percent are predicted to experience worsening ozone concentrations. Regulatory Impact Analysis at 6-13, 6-14.

[178] *Fact Sheet for Communities with Environmental Justice Concerns, Greenhouse Gas Standard and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule*, EPA (last accessed May 15, 2023).

[179] Proposed Rule at 649.

[180] *Id.*

[181] Regulatory Impact Analysis at ES-9.

With respect to US electric grid impacts, EPA explains that many non-regulatory factors have caused the power sector to change and that the power sector will continue evolving in the future, regardless of any EPA action pursuant to CAA section 111. EPA also states that "[p]reserving the ability of power companies and grid operators to maintain system reliability has been a paramount consideration" in developing the rules, which "provide multiple flexibilities that preserve the ability of responsible authorities to maintain electric reliability."[182] EPA states that between 2010 and 2021, total US grid capacity increased by 13 percent while over a third of the coal fleet was retired or rerated.[183]

EPA explains that between 2015 and 2020, coal plants retired at an average rate of 11 GW per year and estimates that total coal retirements between 2023 and 2035 to be 104 GW (15 GW annually) under the baseline compared to 126 GW (18 GW annually) under the proposal.[184] EPA states that companies will comply based on their "least-cost decisions on how to achieve efficient compliance with the rules while maintaining sufficient generating capacity to ensure grid reliability."[185]

For new gas capacity, EPA projects additions in the baseline and proposed rule, with a slightly greater amount under the proposal. EPA estimates that under the proposal, by 2035 there will be 25 GW of economic NGCC additions, which is 300 MW more than the baseline, and 43 GW of economic NGCT (i.e., simple cycle) additions, which is 23 GW more than the baseline.[186] Of these units, EPA projects that 6 GW of NGCCs and 5 GW of NGCT additions will co-fire hydrogen in 2035.[187]

By 2040, EPA estimates the following installed CCS capacity[188]:

	Baseline (GW)	Proposal (GW)
Coal & CCS	8	9
Natural Gas & CCS	10	8

EPA estimates that the largest retail rate impacts of the proposal will be in 2030, with national electricity rates increasing by 2 percent above the baseline in 2030, 0.24 percent above the baseline in 2035, and 0.08 percent above the baseline in 2040.[189]

Next Steps

Comments on the proposed rule will be due 60 days after its publication in the Federal Register. We will track any regulatory and litigation updates on our Regulatory Trackers, available here: [Regulating Greenhouse Gases from Existing Power Plants—the Clean Power Plan and Affordable Clean Energy Rule and 2023 Power Plant Rules]() and [GHG New Source Performance Standards for Power Plants]().

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182 *Id.* at 660–61.
183 Regulatory Impact Analysis at 2-3.
184 *Id.* at 3-25.
185 *Id.* at 3-25 & 3-26.
186 Regulatory Impact Analysis at 3-26.
187 *Id.*
188 *Id.* at 3-27 to 3-28.
189 *Id.* at 3-29 to 3-31.