COMMENTS OF THE CENTER FOR CLIMATE AND ENERGY SOLUTIONS

Comments of the Center for Climate and Energy Solutions on New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (88 Fed. Reg. 33240 (May 23, 2023)) Docket ID No. EPA-HQ-OAR-2023-0072; FRL-8536-02-OAR

This document constitutes the comments of the Center for Climate and Energy Solutions (C2ES) on the proposed standards of performance for greenhouse gas emissions from electric utility generating units (Proposal), proposed by the U.S. Environmental Protection Agency (EPA) and published in the Federal Register on May 23, 2023.

C2ES is an independent, nonprofit, nonpartisan organization working to secure a safe and stable climate by accelerating the global transition to net-zero greenhouse gas emissions and a thriving, just, and resilient economy. As such, the views expressed here are those of C2ES alone and do not necessarily reflect the views of members of the C2ES Business Environmental Leadership Council (BELC). In addition, the comments made in this document pertain to sources in the specific sector addressed by the Proposal and may not be appropriate for other sectors.

Statement of Support

The EPA's Proposal will protect Americans' health and provide significant net economic benefits by accelerating the reduction of harmful climate and air pollution from coal- and natural gas-fired electric power plants. The power sector is one of the largest sources of climate pollution in the United States. With electricity demand set to grow as more cars, buildings, and factories connect to the grid, it is even more important that we rapidly reduce greenhouse gas emissions from electric power generation. These standards, along with the Infrastructure Investment and Jobs Act (IIJA), the Inflation Reduction Act (IRA), and the recently announced vehicle standards proposal, represent crucial steps toward our nation's commitment to reduce greenhouse gas emissions to net zero by 2050.

In *Massachusetts v. EPA*, the Supreme Court affirmed that the EPA has the authority and obligation to regulate carbon dioxide as an air pollutant under the Clean Air Act, and this authority and obligation is reaffirmed in the IRA. The proposed clean air standards for power plants not only represent EPA's statutory duty under the law to protect the public health and welfare, but they also provide an important complement to existing laws. Thanks to the IRA's climate provisions, clean energy technologies like carbon capture and sequestration (CCS) and clean hydrogen—both of which are available now—are poised to scale significantly while coming down in cost. A legally-durable final Section 111 rule will fulfill EPA's obligations under the Clean Air Act by ensuring that power plants deploy the necessary technologies to cut carbon pollution while also providing important regulatory certainty to encourage planning and investment in the electric power sector.

Estimates based on the latest climate science suggest that the net benefits from this proposed rule—in the form of longer lives, improved health outcomes, and a stronger economy—will range from $64 to $85 billion.[1] EPA is also rightly proposing to allow states flexibility in implementing the standards, including the use of approaches like trading and averaging, which can allow states to achieve the same emissions cuts even more cost-effectively.

Already, the power sector has reduced emissions by over 35 percent since 2005 as it continues to transition away from coal, and many power companies have committed to achieve net-zero emissions by 2050. This rule creates an opportunity to bring that year forward and achieve net-zero targets and the associated benefits much sooner. What businesses need most is durable regulatory certainty, so that they can make the investments in clean energy technology necessary to meet those commitments and strengthen them further. C2ES looks forward to working with power companies and the EPA to develop a final rule that is simultaneously strong, flexible, and durable—and that, most importantly, meets the urgency of the climate crisis.

General comments

Waiting to act on emission reductions is not an option; the Proposal conveys this important signal to the power sector as it establishes new source performance standards (NSPS) and emission guidelines for affected electric generating units (EGU). It creates clear timelines over which greenhouse gas emissions from larger, frequently used EGUs must be nearly phased out. Without delay, it requires power plant operators to examine their future generation requirements in conjunction with the current emission profiles of their fleets and make investment decisions about which plants they will modify, which plants they will retire, and which types of plants they will construct in the future.

The Proposal delivers only modest emission reductions in the short term (i.e., before 2032), but this is understandable considering the critical need to maintain system reliability, affordable electricity, and time to further develop the infrastructure and technology for incorporating clean hydrogen and CCS (discussed in more detail below). Still, the EPA estimates that the Proposal will cause power sector emissions to fall by 89 million tons per year by 2030. Even before this Proposal, many coal plants were already expected to retire before 2030. Evaluation of the investments required at individual EGUs to comply with EPA's Proposal is likely to lead to more coal plant retirements rather than fewer. Therefore, C2ES estimates that the Proposal could contribute one to two percentage points of the current U.S. nationally determined contribution to the Paris Agreement to reduce net-emissions 50–52 percent below 2005 levels by 2030.

As the largest historical emitter by far and as a country that contributes around 12.5 percent of global greenhouse gas emissions each year, the actions that the United States takes to mitigate emissions matter. Ultimately, the Proposal is expected to avoid more than 600 million metric tons of carbon dioxide emissions cumulatively between 2028 and 2042 along with the reduction of tens of thousands of tons of harmful air

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

pollutants (e.g., PM2.5, sulfur dioxide, and nitrogen oxides) compared to the baseline.[2] Every fraction of a degree of temperature rise that we can avoid matters to help stave off the worst impacts of climate change at home and around the world.

The remainder of these comments proceed as follows: C2ES comments on the two proposed Best Systems of Emission Reduction, i.e., hydrogen and CCS; then, C2ES provides specific comments on coal and natural gas EGUs; finally, C2ES comments on rule compliance by the states.

Hydrogen

With regard to the use of hydrogen in existing and new natural gas plants, we concur with EPA's assessment that co-firing or blending hydrogen with natural gas (i.e., methane) has been adequately demonstrated up to the level of running these plants exclusively on hydrogen.[3]

Plant operators and the primary manufacturers of natural gas power plants have demonstrated co-firing hydrogen and natural gas for more than a decade.[4] Most natural gas plants that have been deployed over the past two decades are already capable of operating with nominal levels of hydrogen blending, e.g., five to nearly 40 percent; with modest efforts, most plants could be capable of operating on a 30 percent hydrogen blend (by volume).[5] However, modifying existing natural gas plants to operate with much higher levels of hydrogen blending will require additional time and investments. In most instances, retrofits will require taking plants offline for a few months. Plant modifications can be scheduled during periods of lower electricity demand (e.g., typically the spring and autumn) to avoid supply shortfalls or reliability issues. Additionally, since hydrogen behaves differently than natural gas, modified plants will need to undergo suitable safety testing during their out-of-service period. We believe that plant modifications and safety testing can be reasonably achieved in the timeframes in the Proposal.

Prior to the announcement of the Proposal, new generating units using natural-gas-to-hydrogen technology had already been announced. For example, the Intermountain Power Project near Delta, Utah, is expected to commence commercial operation in July 2025 running on 30 percent hydrogen and transitioning to 100 percent by 2045;[6] the Long Ridge Energy Terminal in Hannibal, Ohio, has been testing low-level hydrogen blends and plans to transition to 100 hydrogen;[7] and the Orange County Advanced Power Station will enter service in Southeast Texas in 2026 as a hydrogen-capable facility.[8]

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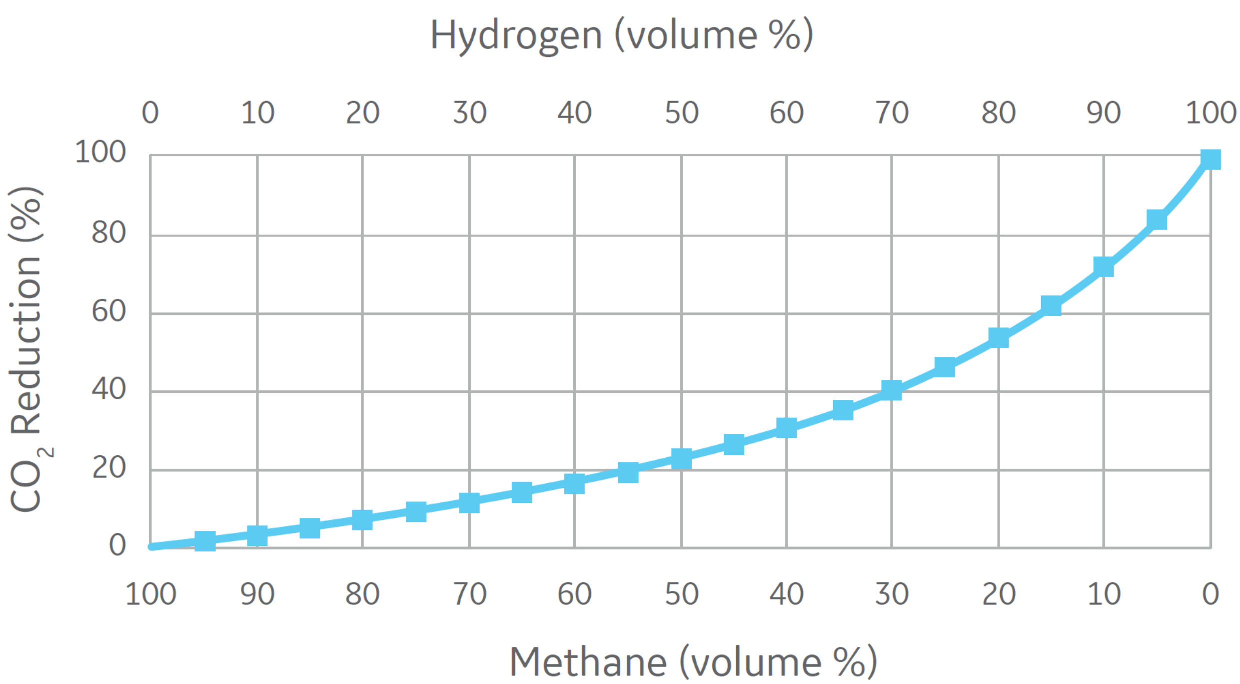
[2] U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, *Regulatory Impact Analysis*.
[3] "Hydrogen fueled gas turbines," GE Gas Power, accessed July 2023, https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines.
[4] Kevin Clark, "OEMs weigh in on hydrogen, decarbonization and the gas turbine," Power Engineering, March 15, 2023, https://www.power-eng.com/gas/gas-turbines/oems-weigh-in-on-hydrogen-decarbonization-and-the-gas-turbine.
[5] Kevin Clark, "Constellation completes hydrogen blending test at Alabama gas-fired plant," Power Engineering, May 24, 2023, https://www.power-eng.com/news/constellation-completes-hydrogen-blending-test-at-alabama-gas-fired-plant.
[6] "About IPP Renewed," Intermountain Power Agency, accessed June 2023, https://www.ipautah.com/ipp-renewed.
[7] Sonia Patel, "First Hydrogen Burn at Long Ridge HA-Class Gas Turbine Marks Triumph for GE," *Power Engineering*, April 22, 2022, https://www.powermag.com/first-hydrogen-burn-at-long-ridge-ha-class-gas-turbine-marks-triumph-for-ge.
[8] "Planning for the future," Entergy, accessed June 2023, https://www.entergy.com/entergypowerstexas/future.

Co-firing hydrogen and natural gas can significantly reduce carbon dioxide emissions. Figure 1 shows how carbon dioxide emission reductions from combustion increase with higher volumes of hydrogen blending.[9] For example, hydrogen blending at the 30 percent level (i.e., 30 percent hydrogen and 70 percent natural gas by volume) results in a 10 percent reduction in carbon dioxide emissions, and hydrogen blending above the 95 percent level results in a 90 percent or greater reduction in carbon dioxide emissions.

Figure 1: Relationship between combustion-related CO2 emissions and hydrogen/methane fuel blends (volume %)



Emissions reductions cited here are for combustion only and do not include upstream emissions.

Source: General Electric Company, Hydrogen for Power Generation (2022).

While we believe that plant modifications and safety testing can be reasonably achieved in the timeframes in the Proposal, we do have areas of concern, particularly with regard to the availability and deliverability of clean hydrogen.

There are several pathways to produce hydrogen. Currently, the primary and cheapest production pathway is steam methane reforming (SMR), which uses high temperatures to produce hydrogen from natural gas; the process also generates a lot of carbon dioxide. For each kilogram of hydrogen produced by SMR, around nine kg of carbon dioxide are created—even without considering fugitive and other emissions created upstream in

[9] General Electric Company, *Hydrogen for Power Generation* (Boston, MA: General Electric Company, 2022), https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf.

the natural gas value chain.[10] Utilizing hydrogen produced in this manner would not deliver the necessary power sector greenhouse gas emission reductions.

Much cleaner hydrogen production pathways are necessary in order to achieve emission reductions. Still, there is another pressing concern—sufficient volumes of cleaner hydrogen would need to be available to the power sector (and other end users) by 2032 so that hydrogen blending is a feasible option to achieve the standard in the Proposal. Additional cleaner hydrogen production techniques include SMR with CCS, which can reduce emissions from unabated SMR by 95 percent, and electrolysis of water using zero-emission sources like wind, solar, hydro, and nuclear, which can generate hydrogen with very low carbon intensities.

To ensure that much cleaner hydrogen is produced, we agree with the Proposal's recommendation that a "low-GHG hydrogen" or a clean hydrogen standard be used for this proposed best system of emission reduction (BSER). The Proposal suggests that only hydrogen produced with a carbon intensity lower than 0.45 kg of carbon dioxide per kilogram of hydrogen produced could qualify as low-GHG hydrogen for the purposes of this rule. Currently, only hydrogen produced through electrolysis, which uses clean electricity (e.g., solar, wind, nuclear and hydro power) to split water into hydrogen and oxygen, achieves 0.45 kg of carbon dioxide per kilogram of hydrogen.[11] However, we believe that this standard is far too limiting with respect to the timeframes laid out in the Proposal and is unlikely to spur the necessary hydrogen volumes and the delivery system (i.e., infrastructure). We acknowledge that with an extended timeline, perhaps three to five years, the proposed stricter standard could potentially deliver the necessary hydrogen volumes.

Today, nearly all U.S. hydrogen production is from SMR. However, provisions in the IRA—namely a hydrogen production tax credit (PTC), which provides up to a $3/kg credit—are designed to spur growth of cleaner production pathways by significantly lowering costs. IRS guidance on the PTC is expected in the coming weeks. Rules that the IRS sets will impact how quickly a clean hydrogen industry develops, if at all. Too many restrictions in the guidance for the hydrogen PTC could forestall a growing industry and prevent a key decarbonization tool from realizing its full potential. For example, some stakeholders are advocating for additionality—a concept that would require hydrogen production facilities to rely on newly built (i.e., additional) clean electricity generation in order to be eligible to receive the PTC. Additionality, and other proposed burdens on a nascent hydrogen industry, could pose a genuine risk to the industry's overall development, as it would exclude existing nuclear plants (i.e., one of the best ways to produce large volumes of electrolytic hydrogen) from receiving the PTC.[12] We recommend that EPA work closely with Treasury on 45V guidance to ensure a robust clean hydrogen ecosystem that meets the timelines and needs of the Proposal emerges.

We are concerned that setting a stringent 0.45 kg carbon intensity from the start will not deliver the necessary hydrogen volumes to meet the power plant standard, i.e., 30 percent blending by 2032—especially given the need to produce clean hydrogen for other important use cases (e.g., steel, fertilizer, chemicals, and long-

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[10] International Energy Agency, *The Future of Hydrogen* (Paris, France: International Energy Agency, 2019), https://www.iea.org/reports/the-future-of-hydrogen.
[11] We assume that this carbon intensity is determined on a lifecycle basis.
[12] Doug Vine, "The stakes for hydrogen just got higher," *Climate Compass* (blog), Center for Climate and Energy Solutions, May 26, 2023, https://www.c2es.org/2023/05/the-stakes-for-hydrogen-just-got-higher.

distance heavy-duty transportation). We believe that a less strict carbon intensity for low-GHG hydrogen would be far more likely to deliver the hydrogen volumes necessary for power plant co-firing under the proposed rule, while still delivering significant emission reductions.[13] Notably, a less stringent carbon intensity would increase the number of available pathways to produce clean hydrogen, including SMR with carbon capture (i.e., so called "blue" hydrogen) as well as methane pyrolysis, which directly splits natural gas (i.e., breaks the hydrogen-carbon chemical bonds) under high temperature to create hydrogen and solid carbon.

Direct (at the facility) blue hydrogen production emissions range from 0.45 to 0.9 kg carbon dioxide equivalent per kg of hydrogen produced for 95 to 90 percent capture rates, respectively; efficiently producing hydrogen with methane pyrolysis would create no carbon dioxide at the point of production. However, upstream emissions from natural gas production can add an additional 1.9 to 5.2 kg carbon dioxide equivalent (global average is 2.7 kg carbon dioxide equivalent/kg hydrogen) to the lifecycle emissions.[14]

Therefore, raising the carbon intensity limit for low-GHG hydrogen to a range of three to four kg carbon dioxide per kg of hydrogen produced on a lifecycle basis, which is consistent with the maximum emission rate allowed in order to earn the minimum hydrogen PTC in the IRA, would help to ensure that production volumes are sufficiently high to meet a wide range of potential hydrogen demand across the economy, while spurring the necessary infrastructure to store and transport hydrogen via pipeline and other means. Note that C2ES supports strong federal and state efforts to mitigate methane emissions at all points along the natural gas value chain (e.g., production, processing, transmission, and storage operations). Furthermore, we support lowering the carbon intensity for hydrogen over time to encourage the use of lower emission natural gas (i.e., on a full lifecycle basis), as long as necessary hydrogen production volumes are able to be met. We propose that EPA conduct a periodic review to evaluate progress on producing the lowest GHG hydrogen possible that meets market demand and reserve the ability to ratchet down the hydrogen carbon intensity limit as very low GHG hydrogen production volumes increase, as it has done with other regulations under similar circumstances.

There is an additional challenge to consider with this proposed BSER as well, particularly as it relates to the deliverability of hydrogen to existing natural gas plants.

Even with improved flexibility with respect to hydrogen production pathways, there are still concerns as to whether sufficient infrastructure (i.e., pipelines and storage) could be put in place in the next eight years to meet the needs of all existing and new natural gas fired power plants that operate more than 50 percent of the time and are planning to continue operating with the new standards. To summarize, an existing gas turbine EGU could relatively easily make the necessary modifications at the plant to be capable of co-firing 30 percent hydrogen prior to 2032, and sufficient volumes of low-GHG hydrogen could be produced in aggregate across the country (assuming a higher three to four kg carbon dioxide carbon intensity); but it is

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[13] For example, direct emissions from producing hydrogen using other clean pathways, e.g., SMR with CCS or methane pyrolysis, would not materially change EPA's emissions calculations. However, indirect or lifecycle emissions from the natural gas value chain would diminish EPA's emissions calculations by the level of upstream emissions. The more cleanly the natural gas is produced, the greater the overall emission reductions.
[14] International Energy Agency, *Global Hydrogen Review 2021* (Paris, France: International Energy Agency, 2021), https://iea.blob.core.windows.net/assets/5bd46d7b-906a-4429-abda-e9c507a62341/GlobalHydrogenReview2021.pdf.

unlikely that a system to safely store and transport hydrogen to where it would be used could be fully completed in such a short period.

There are more than 3 million miles of interstate and local distribution natural gas pipelines in the United States. This network was built out over many decades. Building a dedicated (100 percent hydrogen) network in the next eight years, before compliance of the rule starts to be required in 2032 (i.e., 680 lbs CO_2/MWh-gross), or even the next 14 years, before the start of the stricter performance standard (90 lbs CO_2/MWh-gross) in 2038, would pose significant challenges. Some experts believe that a hydrogen blend of up to 20 percent hydrogen and 80 percent natural gas could be transmitted in existing natural gas pipeline networks (testing is underway to explore this opportunity), but many pipelines are already fully subscribed and there are risks (e.g., embrittlement) with transferring higher blends.[15] It is unclear how willing pipeline owners and operators might be to allow higher blending levels. While it is a possibility that existing natural gas pipelines could be modified with a liner or coating to accommodate higher level hydrogen blends, much in the way of demonstration and testing would be required to certify safe and reliable solutions. Notably, a future hydrogen pipeline network does not need to replicate or be as extensive as the existing natural gas system, particularly in its earlier years; initially, it should be optimized (i.e., laid out) to support entities that can be dependable early adopters (e.g., power sector EGUs), current consumers of highly carbon intensive hydrogen, and end users in hard-to-abate sectors (e.g., industrial applications like steel and high temperature process heat, long-distance heavy-duty trucking, and maritime applications like ports and shipping fuels). Another mitigating factor is that not all affected power plants will need to blend hydrogen; they will have other options under the Proposal, including adopting CCS (discussed below).

Significant demonstration and testing need to occur to provide greater certainty on how the hydrogen system of the future will operate safely and reliably. It is important to note that hydrogen itself is an indirect greenhouse gas that, if permitted to leak in large quantities (i.e., if production and infrastructure do not account for this), could undermine the purpose of the Proposal and exacerbate global warming.[16]

The IIJA provided $7 billion dollars to kickstart regional hydrogen hub development. As many as 10 hubs are expected to receive funding. The amount of private capital that can be leveraged from the government funding will ultimately determine the size, scope, and impact of each hub. The expectation according to the Department of Energy funding opportunity announcement is that these—nearly from scratch—hubs will develop over 8 to 12 years, overlapping with the compliance date of the proposed rule.[17] However, the amount of hydrogen produced by the hubs and available to power generation, as well as the extent to which the necessary hydrogen infrastructure can be built, to serve the power sector in particular, remains uncertain.

Other factors that will exacerbate this challenge include higher interest rates and higher commodity costs (i.e., inflation), which means that less infrastructure will be built than in the absence of these factors. An additional

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[15] Sunita Satyapal et al., *Pathway to Commercial Liftoff: Clean Hydrogen* (Washington, DC: U.S. Department of Energy, 2023), https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.
[16] Ilissa B. Ocko and Steven P. Hamburg, "Climate consequences of hydrogen emissions," *Atmospheric Chemistry and Physics* 22, no. 14 (2022) 9349–9368, 2022, https://doi.org/10.5194/acp-22-9349-2022.
[17] "Funding Notice: Regional Clean Hydrogen Hubs," Office of Clean Energy Demonstrations, accessed June 2023, https://www.energy.gov/oced/funding-notice-regional-clean-hydrogen-hubs.

hurdle is permitting, particularly for pipelines, storage, and compressor stations. Efforts are underway in Congress and at government agencies to accelerate the pace of permitting reform, but the outcome of those reforms remains uncertain.

In sum, there are a number of challenges associated with the timely development of clean hydrogen by 2032: overly prescriptive IRS guidance on the IRA's hydrogen PTC, uncertainty around the timeliness of sufficient production volumes of low-GHG hydrogen to meet power sector and all other demand, and how quickly infrastructure can be put in place to safely store and transport hydrogen in the face of economic and permitting challenges. For these myriad reasons, it is uncertain whether hydrogen supply and the necessary infrastructure will be in place to meet demand by 2032.[18] However, hydrogen remains an important option for decarbonizing natural gas-fired power plants and may be a critical alternative in regions of the country that lack suitable geology for carbon capture. Should EPA pursue hydrogen as a BSER, which we believe it could, we recommend that EPA perform regularly scheduled (e.g., yearly) and publicly transparent assessments leading up to 2032, designed in good faith with EGU owners to ascertain hydrogen's readiness (e.g., looking at factors like infrastructure buildout and clean production volumes). EPA should also provide the clearest and longest-term signal possible of any potential delays in the implementation years as an additional safety valve. We note that EPA retains the ability to amend or revise hydrogen blending requirements for new and existing natural gas EGUs with future notice and comment rulemaking based on these assessments.

Carbon Capture

With regard to the use of carbon capture utilization and storage (CCS) on existing coal- and natural gas-fired power plants and new natural gas-fired plants, we concur with EPA's assessment that this technology has been adequately demonstrated for capturing and sequestering 90 percent of carbon dioxide emissions from power generation.

Unit 3 at SaskPower's Boundary Dam coal-fired power plant in Estevan, Saskatchewan, which entered service in 2014 has demonstrated 90 percent carbon dioxide capture rates while operating at high capacity factors.[19] Additionally, the now-idle Petra Nova coal-fired power plant in Texas achieved a greater than 90 percent capture rate when it was operational.[20] However, as first movers, these plants did have difficulty consistently maintaining high capture rates for weeks at a time.[21]

While post-combustion CCS technology is advanced, challenges remain to improve the reliability of high capture rates at power plants. Additionally, to date, no existing natural gas power plant has been retrofitted with CCS technology. With lower carbon dioxide content relative to coal-fired plants in the flue gas (i.e.,

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[18] Sunita Satyapal et al., *Pathway to Commercial Liftoff: Clean Hydrogen*.
[19] Stavroula Giannaris et al., "SaskPower's Boundary Dam Unit 3 Carbon Capture Facility - The Journey to Achieving Reliability" (paper presented at the Proceedings of the 15th Greenhouse Gas Control Technologies Conference, Abu Dhabi, UAE, March 15-18, 2021), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820191.
[20] Greg Kennedy, *W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)*, DOE-PNPH-03311 (Washington, DC: U.S. Department of Energy, 2020), https://www.osti.gov/biblio/1608572.
[21] Outages are sometimes unrelated to capture equipment (e.g., planned outages, plant shutdown, unique problems/equipment for a specific facility).

exhaust gases produced at power plants), CCS from natural gas plants will require larger, more energy-intensive systems.[22]

While challenges exist for post-combustion CCS, we do not think they are insurmountable in the timeframes recommended in the Proposal. Other technologies, namely oxy-combustion, that would be compatible with new natural gas plants are very promising.

Oxy-combustion systems burn natural gas in pure oxygen versus air, which is mostly nitrogen. This results in a flue gas that is mostly carbon dioxide and water, which greatly simplifies the capture process. NET Power has demonstrated oxy-combustion with their proprietary technology at their 50 MW test facility in La Porte, TX (which was successfully synchronized with the grid in 2021), and expects to deliver a full-scale (i.e., 300 MW) plant that captures all of its carbon dioxide emissions by 2026.[23]

Enhanced credits in the IRA for CCS (i.e., 45Q in the Internal Revenue Service code) that are available for projects that commence construction prior to 2033 can help offset the cost of deploying and operating CCS systems.

Still, and not unlike the issues discussed previously for hydrogen, there are infrastructure challenges related to deploying CCS. Not every fossil fuel-fired plant is located in close proximity to suitable geological storage.[24] Therefore, carbon dioxide pipeline networks need to be proposed and approved that connect sources and approved storage sites. Larger trunk lines need to be strategically laid, allowing for easy connection (via feeder lines) to power plants and industrial facilities that are considering deploying CCS and, in the case of industrial facilities, may use carbon dioxide as a feedstock for producing low-carbon fuels, among other things.

C2ES believes and statistics show that pipelines are the safest, most efficient and economic form of transportation for carbon dioxide and other products (e.g., natural gas, oil, hydrogen).[25] However, pipeline projects can take many years to permit and construct—in many cases, more than five years to become operational.

While there are more than 5,000 miles of carbon dioxide pipelines in operation across the country, they do not comprise a network.[26] But they do demonstrate that carbon dioxide pipelines are technologically mature,

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[22] U.S. Department of Energy, *Carbon Capture Opportunities for Natural Gas Fired Power Systems* (Washington, DC: U.S. Department of Energy, 2017), https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.

[23] Sonal Patel, "NET Power's First Allam Cycle 300-MW Gas-Fired Project Will Be Built in Texas," *Power Mag*, November 10, 2022, https://www.powermag.com/net-powers-first-allam-cycle-300-mw-gas-fired-project-will-be-built-in-texas.

[24] Note that the United States has vast capacity both onshore and offshore for stable long-term carbon dioxide storage.

[25] Pipeline and Hazardous Materials Safety Administration, "PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak," news release no. PHMSA 05-22, May 26, 2022, https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.

[26] Many of these lines connect a source of carbon dioxide (e.g., natural underground deposit, industrial facility or power plant) to a point of geological storage (e.g., saline formation or used for enhanced oil recovery).

and that we do know how to site, build, and operate them safely.[27] Studies suggest that the quantity of carbon dioxide pipeline miles will need to increase more than tenfold over the next 25 years to be consistent with net-zero economywide emissions by 2050.[28]

Another challenge is approving sites for permanent sequestration. For each project, so-called Class VI wells for deep geological storage in saline formations require approval by federal and state authorities as the destination for the captured carbon, which is a time-consuming endeavor. Some have argued that the permitting process can be accelerated if the EPA grants primacy to more states. To-date, EPA has only approved a handful of Class VI wells, and only North Dakota and Wyoming have primacy over Class VI wells; Louisiana is expected to be granted primacy later this year.

We recommend that EPA devote more resources (i.e., hiring additional staff, conducting more training), some of which were allocated to the agency in the IRA, to reviewing Class VI permits and standardizing the internal technical processes as it receives more applications. Similarly, EPA should review state primacy applications in a timely manner and assist states in establishing their review processes.

While the technology for deploying CCS at individual EGUs is mature, there are notable challenges to overcome for this technology to be effectively deployed before 2030. Many things have to go right with regard to overcoming permitting challenges for both carbon dioxide pipelines and permanent geological storage. Suffice it to say, the timelines are tight for coal plants (long-term units) that are required to install CCS by 2030, particularly for units that are not located in close proximity to suitable geological storage. Ultimately though, we believe that CCS is a more mature technology than hydrogen.

Coal plants

C2ES commends the approach taken in the Proposal that places the toughest requirements on EGUs that operate the most often, which covers the greatest quantity of emissions.

Under the Proposal, by 2040, coal plants will have either retired or been retrofitted with CCS with a 90 percent capture rate. We believe that that the Proposal could be improved by bringing this date forward to perhaps as early as 2035, subject to reliability concerns. Indeed, there is value in bringing the date forward by even one or two years. Notably, many utilities have previously announced significant coal plant retirements in the next 5 to 10 years.

Accelerating the retirement of coal-fired power plants can have an outsized impact on carbon emission reductions, and every fraction of degree of warming that can be avoided matters. Additionally, coal plants

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[27] Pipeline and Hazardous Materials Safety Administration, "PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak."

[28] Eric Larson et al., Net-Zero America: Potential Pathways, Infrastructure, and Impacts (Princeton, NJ: Princeton University, 2021), https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf; Rory Jacobson et al., *Pathway to Commercial Liftoff: Carbon Management* (Washington, DC: U.S. Department of Energy, 2023), https://liftoff.energy.gov/wp-content/uploads/2023/04/20230424-Liftoff-Carbon-Management-vPUB_update.pdf; Elizabeth Abramson, Dane McFarlane, and Jeff Brown, Transport Infrastructure for Carbon Capture and Storage (Minneapolis, MN: Great Plains Institute, 2020), https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf.

emit conventional pollutants such as sulfur dioxide, nitrogen oxides, and particulate matter; release mercury, lead, and other air toxics; and create large quantities of ash residues of varying toxicity levels. Though not related to climate change, these emissions and outputs can create a range of health and environmental impacts, particularly for communities located nearby coal facilities. Earlier retirements would help to mitigate these effects sooner.

Certain coal plants, depending on their location, may be needed, although in a lower capacity, to help shore up and preserve electric system reliability beyond the timeframes outlined in the Proposal. The rule should provide the flexibility to allow limited and rare exceptions for plants that may need to run to provide ancillary services and prevent system reliability issues from occurring.

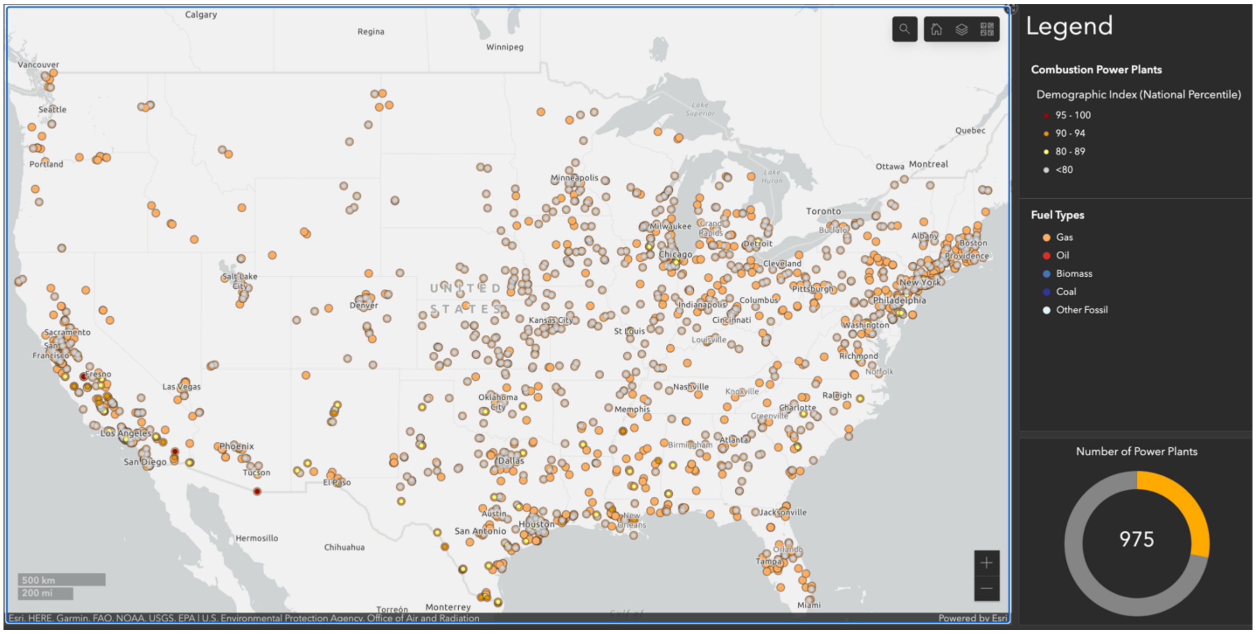
Natural gas plants

C2ES commends the approach taken in the Proposal that places the toughest requirements on natural gas-fired EGUs that operate at higher capacity factors, which covers the greatest quantity of emissions.

However, we believe that the Proposal exempts too many existing units. We agree with the need to explore appropriate regulations for "peaker" plants in the future. Additionally, we believe that EPA should test the boundaries for intermediate and baseload plants, potentially shifting to a capacity factor below 50 percent and a unit size below 300 MW to expand the number of units covered by the proposed standard.

We agree with EPA and recommend that a future rule, promulgated quickly, should focus on peaker plants to reduce the significant number of emissions that they generate. This is important not only for climate, but for health and environmental reasons. In many cases, peaker plants tend to be located nearer to population centers—often in disadvantaged communities—affecting a greater number of people (Figure 2). Because these EGUs start and stop more frequently, they have higher emissions rates of carbon dioxide and air pollutants like nitrogen oxides, which are harmful to human health and the environment. Peakers also play an important role in ensuring grid reliability. And because of their relatively limited operation, they are only marginally profitable.

Figure 2: Intermediate power plants and neighboring communities



A screenshot from the Power Plants and Neighboring Communities Mapping Tool where you can see the overlap between intermediate (peaker) plants and the average of two demographic indicators; Percent Low-Income and Percent Minority.

Source: U.S. Environmental Protection Agency, Power Plants and Neighboring Communities Map (2022).

Energy storage is one technology that should be considered to displace peaker capacity, particularly for units that are used more frequently (i.e., nearly daily, but for short periods). Storage can potentially be deployed at the site of a natural gas peaker plant or in other strategic locations and still mitigate the amount of natural gas peak generation that is required during daily peaks from a particular EGU (i.e., from a physics perspective, it need not be co-located). Depending on the size of the EGU, energy storage could displace some or all of the electricity generation. However, the cost and the duration of energy storage needed should be considered. To maximize emission reductions, electricity from zero-emission sources (e.g., wind, solar, hydro, and nuclear) should be used to charge batteries (i.e., energy storage), but low carbon intensity grid-connected electricity (i.e., less than 500 pounds of carbon dioxide per megawatt-hour) should be considered as well. C2ES recommends studying the potential for a BSER for peaker plants designed around these principles.

State implementation plans for compliance

In the Proposal, EPA has recommended emission standards for existing EGUs based on plant size, how frequently plants are utilized, and when plants are expected to retire. For existing sources, states are ultimately responsible for submitting plans to the EPA for approval (i.e., compliance). In aggregate, these plans must achieve emission reductions equivalent to the emission reductions that would result by applying the proposed performance standards across all affected individual EGUs within the state.

EPA is rightly proposing to allow states flexibility in complying with the standards, including the option to use market-based approaches like emissions trading and averaging, which can allow states (if they choose to adopt this approach) to achieve the same emissions reductions even more cost-effectively. As the Proposal notes, market-based approaches (e.g., trading and averaging) have played a key role in other Clean Air Act regulations by enabling market forces to reduce emissions cost effectively. A pollutant like carbon dioxide is well-suited for market-based approaches because the environmental harm depends on the global concentration and not a specific location of origin. The environmental benefit from preventing the emissions of one ton of carbon dioxide is identical regardless of where it occurs. However, the economic cost could vary from one source to another. When the economic cost varies from sources, especially across a national versus state market, there can be benefits from trading.

We look forward to EPA's suggestions of approvable averaging and trading approaches in the future. We believe that allowing sources to exchange emission credits or allowances is the most efficient way of reducing emissions and meeting electricity demand while harnessing market forces to spur clean energy innovation, development, and deployment.

We appreciate the additional flexibility that is provided to states through the remaining useful life and other factors (RULOF) mechanism outlined in the Proposal. With this mechanism, states could apply a less stringent performance standard to a particular EGU by considering other factors such as remaining useful life, unreasonable cost of control, physical impossibility or technical infeasibility of installing necessary equipment, or other circumstances. We believe that this is an appropriate safety valve to protect EGUs that are making good faith efforts to comply with power plant standards.

Invoking RULOF would allow a state to apply a less stringent standard for a source specific EGU in certain cases where a lack of hydrogen and/or carbon dioxide infrastructure makes those technologies infeasible. To limit invoking of lesser standards and to maintain the integrity of the Proposal, we encourage the EPA, states, and other stakeholder to work collaboratively and in good faith. For example, as coal plants planned to comply with the Mercury and Air Toxics (MATS) rule, the EPA developed a transparent process in conjunction with stakeholders that established milestones and led to informed decision-making. As hydrogen and carbon dioxide infrastructure and ecosystems develop, EPA should replicate this process to not only incentivize swift development, but to determine where legitimate compliance extensions are warranted. EPA should only approve RULOF cases where there is clearly documented evidence (e.g., receipts, invoices, actual site work) that a source-specific EGU is making best endeavors to achieve compliance as expeditiously as possible.