Hydrogen Co-Firing and the EPA's Greenhouse Gas Limits for Power Plants

Policy Strategies for Meaningful Emission Reductions

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Executive Summary

In May 2023, the Environmental Protection Agency (EPA) proposed new limits for carbon dioxide (CO_2) emissions from fossil fuel-fired power plants (the Proposed Rule) using its authority under Section 111 of the Clean Air Act (CAA).[1] The Proposed Rule reflects a decade of careful development from EPA and embraces an approach consistent with the Supreme Court's ruling in *West Virginia v. EPA*.[2] In that decision, the Court expressed support for emission limits based on technologies that reduce pollution by causing sources to operate more cleanly.[3] Accordingly, in the Proposed Rule, EPA based the limits for certain natural gas-fired turbines on the emission reductions achievable through hydrogen co-firing (i.e., burning a blend of natural gas and hydrogen).

Unlike fossil fuels, hydrogen does not release CO_2 when burned. But *producing* hydrogen can cause significant greenhouse gas (GHG) emissions. The most common way to make hydrogen is through "steam methane reforming," which releases substantial CO_2 as a chemical byproduct. It is also possible to create "electrolytic" hydrogen by splitting water molecules via electricity—a process known as "electrolysis." Electrolytic hydrogen production causes significant GHG emissions when it relies on electricity generated from burning fossil fuels, but few emissions when the electricity comes from renewables or nuclear plants.[4] When the electricity for electrolysis comes from burning natural gas, electrolysis induces twice the GHG emissions of steam methane reforming for the same amount of hydrogen.[5]

Given these potential emissions, the Proposed Rule recognizes that "[c]o-firing hydrogen at combustion turbines when that hydrogen is produced with large amounts of GHG emissions would ultimately result in increasing overall GHG emissions, compared to combusting solely natural gas at the combustion turbine."[6] It is thus important to consider what type of hydrogen a power plant will co-fire with—otherwise this approach to reducing emissions could exacerbate climate change.

This report proceeds in three parts: In Section I, we explain the role of hydrogen co-firing in EPA's Proposed Rule. In the Proposed Rule, EPA determines emission limits for certain gas turbines based on the emission reductions possible when co-firing with "low-GHG hydrogen." Then, in Section II, we discuss how EPA should design its final rules to achieve the specified GHG-reduction goals.[7] The final rules can best meet these goals by retaining the low-GHG hydrogen limitation. Finally, in Section III, we highlight additional actions that EPA and other regulators can take to further minimize the emissions (and the resulting climate harm) from hydrogen co-firing. These actions would play a particularly impor-

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1 New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (proposed May 23, 2023) (to be codified at 40 C.F.R. pt. 60) [hereinafter Proposed Rule].

2 *See* West Virginia v. EPA, 597 U.S. 697 (2022).

3 *Id.* at 2595 (distinguishing the Clean Power Plan, the Obama Administration's policy to reduce greenhouse gases from the power sector, from other Section 111 rules based on the "novelty of its approach . . . [to] '*improve the overall power system*,' rather than the emissions performance of individual sources" (citing Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,661, 64,703 (Oct. 23, 2015))); *see also id.* at 2615 ("We have no occasion to decide whether the statutory phrase 'system of emission reduction' refers *exclusively* to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as the BSER.").

4 *See infra* Section II.A.1.

5 Wilson Ricks et al., *Minimizing emissions from grid-based hydrogen production in the United States*, 18 Env't Rsch. Letters 1, 2 (2023).

6 Proposed Rule, 88 Fed. Reg. at 33,315.

7 Note that EPA has reported that it will finalize the regulations for existing coal-fired plants and new gas-fired plants ahead of the regulations for existing gas-fired plants. *See infra* Section I.A.

tant gap-filling role if EPA adopts a final rule that provides leeway for high-GHG hydrogen to be co-fired, or if a severable low-GHG limitation is struck down by a court.

In the design of a final rule, EPA should:

1. Keep Low-GHG Hydrogen Limitation: EPA should specify the use of low-GHG hydrogen for any emission limits that are premised on hydrogen co-firing. This design choice would better ensure that the rule achieves the maximum net reduction in GHG emissions possible under the rule.
2. Include Severability Provision if Supported by Emissions Analysis: The agency should assess the risk that promulgating an emission limit based on hydrogen co-firing, without specifying the use of low-GHG hydrogen, would lead to a net increase in GHG emissions. It should rely on this assessment to decide whether the low-GHG limitation should be legally severable.
3. Include Verification Protocols that Adequately Address Emissions from Grid Electricity Used by Electrolyzers: EPA should develop verification protocols that accurately account for the emissions of hydrogen production when measuring compliance with the definition of "low-GHG hydrogen," including the treatment of emissions from grid electricity used by electrolyzers. If the Department of Treasury (Treasury) finalizes its strong proposal for verification protocols for the clean hydrogen production tax credit, EPA should adopt those protocols.[8]
4. Ensure Equivalent Emission Reductions from Different Compliance Pathways: If the final rule sets emission limits for some gas turbines based solely on the emission reductions achievable through carbon capture and sequestration/storage (CCS), EPA should provide direction on how to achieve equivalent reductions using hydrogen co-firing—taking into account hydrogen's production emissions.

In Section III, we describe complementary actions that EPA, other federal agencies, and state actors could take to maximize the climate benefits of hydrogen co-firing. Beyond helping to maximize the climate benefits of this rule, these other actions would help ensure that hydrogen generally serves as a climate solution instead of a climate obstacle. A comprehensive regulatory approach is warranted in light of the anticipated expansion of the American hydrogen industry, which is already large[9] and likely to expand significantly in response to incentives in the Inflation Reduction Act (IRA) and the Bipartisan Infrastructure Law (BIL), and in conjunction with the demand for hydrogen induced by this rulemaking.

[8] *See* Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property, 88 Fed. Reg. 89220 (proposed Dec. 26, 2023) (to be codified at 26 C.F.R. pt. 1) [hereinafter Treasury Proposed Rule].

[9] Dep't of Energy, Pathways to Commercial Liftoff: Clean Hydrogen 11 (2023) [hereinafter DOE Commercial Liftoff], https://perma.cc/FB6J-L22K ("[Steam methane reforming] is a mature, carbon-intensive technology representing a $10–12B annual domestic market (<2% CAGR from 2015–2020) with ~10 MMTpa operational across the U.S.").

Federal and state regulators should prioritize the following actions (not listed in order of importance):

1. Finalize Clean Hydrogen Tax Credit: Treasury could finalize its proposed approach for implementing the clean hydrogen production tax credit. Given the proposal's treatment of emissions from the electric grid, it would incentivize the production of truly low-GHG electrolytic hydrogen.

2. Set GHG Limits for Fossil-Based Hydrogen-Production Facilities: EPA could establish air pollution limits under Section 111 of the CAA for fossil-based hydrogen-production facilities.

3. Set Hydrogen Emission Limits for Hydrogen Infrastructure: EPA could establish limits on hydrogen emissions from electrolyzers, gas turbines that co-fire with hydrogen, hydrogen transportation infrastructure, and hydrogen storage infrastructure using its authority under Section 111 of the CAA. Hydrogen is an indirect GHG that contributes to climate change.

4. Set Safety Standards for Pipelines to Prevent Hydrogen Leaks: The Pipeline and Hazardous Materials Safety Administration could promulgate regulations for the detection and repair of hydrogen leaks from pipelines and associated facilities.

5. Update Methane Emission Limits for Oil & Gas Sector: EPA could update pollution limits for methane emissions from the oil and gas sector when emissions-control technologies improve. Addressing these emissions would reduce the lifecycle emissions for hydrogen production that uses methane as a feedstock.

6. Adopt State Policies to Reduce the Lifecycle Emissions of Hydrogen Co-Firing: New state policies could include emission limits for in-state production of hydrogen, restrictions on the lifecycle emissions of hydrogen used for co-firing in state, and subsidies for low-GHG hydrogen production that robustly account for lifecycle emissions.

To the full extent of EPA's legal authority, a final rule should ensure that the GHG reductions from co-firing hydrogen at power plants are not offset by hydrogen-production emissions. At the same time, given the inevitability of litigation and the legal arguments already articulated in comments during this rulemaking, EPA should prepare for the possibility of an adverse ruling on some elements of the rule, including a low-GHG hydrogen limitation. It could do both by clearly signaling its intent for some portions of the rule to be severable from the remainder and by pursuing additional, complementary federal actions that address emissions from hydrogen production.

From the standpoint of maximizing net societal GHG emission reductions, the optimal approach may be a final rule with (1) a robust definition of low-GHG hydrogen and accurate emission-accounting protocol that includes (2) explicit recognition from EPA that the low-GHG limitation is legally severable and is (3) complemented by a whole-of-government effort to reduce hydrogen's lifecycle emissions. The whole-of-government effort would help to ensure that this rule's hydrogen co-firing provisions would mitigate climate change even without the low-GHG limitation.

I. Hydrogen Co-Firing in the Proposed Rule

In May 2023, EPA released the Proposed Rule, which would set new limits under Section 111 of the CAA for CO_2 pollution from fossil fuel-fired power plants. The Proposed Rule contains five major actions, including CO_2 emission limits for new and some existing gas turbines.[10] This section explains how the Proposed Rule relies on hydrogen co-firing to determine emission limits for certain groups of gas turbines.

A. Hydrogen Co-Firing as an Element of the "Best System of Emission Reduction" for Certain Gas Turbines

Section 111 requires EPA to regulate stationary source categories that cause, or significantly contribute to, air pollution that "may reasonably be anticipated to endanger public health or welfare."[11] EPA sets the stringency of these limits, called "performance standards," based on "the degree of emission limitation achievable through the application of the *best system of emission reduction* [(BSER)]" that "the Administrator determines has been adequately demonstrated," after "taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements."[12] A BSER is not a mandate to install a particular technology; instead, it serves as a benchmark for determining the stringency of a performance standard.[13]

For new and modified sources,[14] EPA sets these performance standards directly, based on the emission reductions that would be achieved if the selected BSER were implemented at a source.[15] For existing sources, EPA provides "emission guidelines" that govern states' development of performance standards of equivalent stringency to EPA's emission guidelines.[16] In both cases, source operators can comply with the performance standards using means other than the BSER if they achieve the emissions rates specified by the performance standards.[17]

In its 2023 decision *West Virginia v. EPA*, the Supreme Court reaffirmed that EPA has authority under Section 111 of the CAA to reduce GHG emissions from power plants.[18] The Court held, however, that the approach of a 2015 Obama-era rule called the Clean Power Plan had unlawful design elements. Specifically, the Court took issue with the Clean Power Plan's selection of a BSER based in part on "generation shifting"—shifting electricity generation from coal plants to natu-

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[10] Altogether, the Proposed Rule would: (1) revise standards for new gas-fired stationary combustion units, (2) revise standards for modified fossil fuel-fired steam units, (3) set emission guidelines for existing fossil fuel-fired steam units (including coal- and oil/gas-fired), (4) set emission guidelines for the largest and most frequently operated existing gas-fired stationary combustion turbines, and (5) repeal the Affordable Clean Energy Rule issued by the Trump Administration. Proposed Rule, 88 Fed. Reg. at 33,240.

[11] 42 U.S.C. § 7411(b)(1)(A).

[12] *Id.* § 7411(a)(1) (emphasis added).

[13] The stringency of Section 111 standards is based on the emissions-reduction "performance" of selected technologies, that is the emission reduction that they can achieve, rather than a particular health or environmental outcome, as is the case for certain other CAA provisions.

[14] For simplicity we refer to "new and modified" sources as "new" sources throughout the rest of the report.

[15] 42 U.S.C. § 7211(b).

[16] *Id.* § 7211(d).

[17] *See id.* § 7411(a)(1) ("The term 'standard of performance' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . ."); *see also* Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), 88 Fed. Reg. 80,480, 80,532 (Nov. 17, 2023) ("The EPA is finalizing its proposal that CAA section 111(a) and (d) cannot be interpreted, by their terms, to limit the types of controls that states, in their state plans, may authorize their sources to adopt to at-the-source, and thereby preclude states from authorizing their sources flexibilities such as trading or averaging.").

[18] *West Virginia*, 597 U.S. 697.

ral gas plants and from fossil fuel-fired plants to renewables—which the Court found distinguishable from BSERs based on technologies that incidentally shift the generation mix.[19] The Court recognized that EPA has historically identified BSERs based on actions that individual regulated sources can take, such as "fuel-switching" and "add-on controls."[20]

The Proposed Rule applies this approach endorsed by the Court in *West Virginia*: selecting BSERs that individual sources can implement. Specifically, the BSERs in the Proposed Rule variously include improvements to plant efficiency, installation of CCS, and increased co-firing with cleaner fuels—the last of which involves using natural gas at coal plants and low-GHG hydrogen at gas plants. As EPA notes in the Proposed Rule, "[c]o-firing hydrogen in a combustion turbine in place of natural gas reduces GHG emissions at the source and therefore plainly qualifies as a 'system of emission reduction.'"[21]

Figure 1, adapted from an EPA presentation, summarizes the BSERs in the Proposed Rule for new gas turbines and their associated standards of performance. The Proposed Rule uses "capacity factors"—which refers to frequency and intensity of a generator's operations[22]—to distinguish between subcategories of gas turbines (low load vs. intermediate load vs. base load). The red boxes contain the hydrogen-related provisions, which apply only to new gas turbines with intermediate or base loads. This report refers to these two subcategories of gas turbines as the "hydrogen subcategories." Where a "Low-GHG Hydrogen Pathway BSER" is listed alongside a "CCS Pathway BSER" for the base load subcategory, these turbines can comply with the Proposed Rule by adhering to either pathway.

[19] *Id*. at 725–35.

[20] *Id*. at 727.

[21] Proposed Rule, 88 Fed. Reg. at 33,315.

[22] *Glossary*, Energy Info. Admin., https://perma.cc/2SD6-NZW7 ("Capacity factor: The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.").

Figure 1: Proposed BSER Levels for 111(b) – New Stationary Combustion Turbines[23]

Phase I *(By date of promulgation or upon initial startup)*	**Phase II** *Beginning in 2032-2035*	**Phase III** *Beginning in 2038*
Low Load Subcategory (Capacity Factor <20%)		
BSER: Use of low emitting fuels (e.g., natural gas and distillate oil) Standard: From 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on fuel type	No proposed Phase II or Phase III BSER component or standard of performance	
Intermediate Load Subcategory (Capacity Factor 20% to ~50%)		
BSER: Highly efficient simple cycle generation Standard: 1,150 lb CO_2/MWh-gross	**BSER:** Continued highly efficient simple cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 Standard: 1,000 lb CO_2/MWh-gross	No proposed Phase III BSER component or standard of performance
Base Load Subcategory (Capacity Factor >~50%)		
BSER: Highly efficient combined cycle generation Standard: 770 lb CO_2/MWh-gross (EGUs with a base load rating of 2,000 MMBtu/h or more) Standard: 770 lb – 900 lb CO_2/MWh-gross (EGUs with a base load rating of less than 2,000 MMBtu/h)	**Low-GHG Hydrogen Pathway BSER:** Continued highly efficient combined cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 Standard: 680 lb CO_2/MWh-gross **CCS Pathway BSER:** Continued highly efficient combined cycle generation with 90% CCS beginning in 2035 Standard: 90 lbCO_2/MWh gross	**Low-GHG Hydrogen Pathway BSER:** Co-firing 96% (by volume) low-GHG hydrogen beginning in 2038 Standard: 90 lb CO_2/MWh-gross **CCS Pathway:** No Phase III BSER component or standard of performance

The Proposed Rule also contains emission guidelines for some existing natural gas turbines—which included a BSER pathway based on co-firing with low-GHG hydrogen for large baseload turbines—but the regulation of existing gas has subsequently been put on a different timeline. EPA has reported that it will finalize rules for only existing coal- and new gas-fired turbines in April 2024, and will address existing gas turbines at a later date through a "new, comprehensive approach to cover the entire fleet of natural gas-fired turbines."[24] We do not include the proposed BSER for existing gas turbines in this report because EPA has signaled it will revise the proposal. The findings in this report are, however, still relevant to the regulation of existing gas turbines.

[23] Adapted from Env't Prot. Agency, Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units 8 (2023).

[24] Matthew Daily, *EPA delays rules for existing natural gas power plants until after the November election*, ABC News (Feb. 29, 2024) (statement of EPA Administrator Regan).

Returning to new gas turbines, for the hydrogen subcategories with the dual-pathway BSERs (a hydrogen co-firing pathway and a CCS pathway), EPA solicited comment on whether it should finalize only one BSER pathway.[25] Many commenters who expressed support for the Proposed Rule encouraged EPA to adopt this change.[26] One coalition argued that, "[i]f EPA were to provide two separate BSER pathways for the same set of units, . . . the agency would have failed to discharge its statutory duty to select the 'best' system of emission reduction for the units in that subcategory."[27] These groups recommended that, for all turbines for which EPA has proposed a dual-pathway BSER, EPA should finalize only a CCS-based BSER.[28]

If EPA were to implement this recommendation (without making other major changes to the BSERs), only the new gas turbine subcategory for intermediate load would retain a BSER based on hydrogen co-firing. Yet even if EPA identifies CCS as the sole BSER for a subcategory, a source can still use hydrogen co-firing to comply with the resulting performance standard, so long as it can demonstrate equivalent emission reductions.[29] For this reason, EPA's treatment of hydrogen's lifecycle emissions will matter even for subcategories without hydrogen co-firing BSERs. These same considerations would apply to any existing gas regulations and their implementation when they are eventually finalized.

B. Specifying Use of Low-GHG Hydrogen as a Component of a Hydrogen Co-Firing BSER

The Proposed Rule specifies that "to qualify as the 'best' system of emission reduction, the hydrogen that is co-fired must be low-GHG hydrogen" (the low-GHG hydrogen limitation).[30] While burning hydrogen does not release CO_2,[31] producing hydrogen may cause significant GHG emissions. The primary way to make hydrogen (steam methane reforming) releases CO_2 as a chemical byproduct and uses methane as a feedstock. Methane is itself a GHG that leaks during extraction, transportation, and storage—thus adding to the lifecycle emissions of methane-based hydrogen. It is also possible to create hydrogen by splitting water molecules via electricity ($2H_2O \rightarrow 2H_2 + O_2$)—a process known as electrolysis. The GHG emissions from producing this electrolytic hydrogen depend on the source of the electricity (e.g., coal vs. wind).

EPA explains that the low-GHG limitation is necessary because "[c]o-firing hydrogen at combustion turbines when that hydrogen is produced with large amounts of GHG emissions would ultimately result in increasing overall GHG emissions, compared to combusting solely natural gas at the combustion turbine."[32] As such, EPA states that "[p]ermitting [turbines] to burn high-GHG hydrogen to meet the standard of performance here would ignore an important aspect of the problem being addressed, contrary to reasoned decisionmaking."[33]

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25 Proposed Rule, 88 Fed. Reg. at 33,244.

26 *E.g.*, Clean Air Task Force et al., Comments on Proposed Rule 75–76 (Aug. 8, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0893; New York State Attorney General et al., Comments on Proposed Rule 38 (Aug. 15, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0748.

27 Clean Air Task Force et al., *supra* note 26, at 75.

28 *Id.* at 76.

29 Section II.C of this report emphasizes the steps that EPA would need to take to ensure that units do not undermine the integrity of a CCS-based BSER by co-firing with high-GHG hydrogen.

30 Proposed Rule, 88 Fed. Reg. at 33,315.

31 Instead, the primary byproduct of hydrogen combustion is water: $2H_2 + O_2 \rightarrow 2H_2O$. As is the case with fossil fuel use, burning hydrogen does cause NO_X emissions, because the resulting heat causes oxygen and nitrogen from the ambient air to react together.

32 Proposed Rule, 88 Fed. Reg. at 33,315.

33 *Id.* at 33,316.

EPA proposes to define "low-GHG hydrogen" as hydrogen with an emissions intensity of less than 0.45 kilograms of CO_2 equivalent (CO_2e) per kilogram of hydrogen on a "well-to-gate basis."[34] The term "well-to-gate basis" refers to an incomplete lifecycle analysis limited to: (1) emissions from feedstock production/delivery (e.g., leaked methane) and (2) from the hydrogen-production process (e.g., direct emissions of CO_2 from fossil-based production facilities, and the emissions from producing the electricity that powers electrolyzers).[35]

EPA adopts this emissions-intensity threshold and the well-to-gate system boundary for the lifecycle analysis from the IRA's clean hydrogen production tax credit.[36] The IRA provides the highest tier of tax credits to hydrogen produced with that same emissions intensity (<0.45 kg CO_2e/kg H_2).[37] EPA further proposes to adopt the protocols from Treasury's rule for determining compliance with this <0.45 kg CO_2e/kg H_2 threshold,[38] which was forthcoming at the time of the Proposed Rule's release and has since been published as a proposal.[39] EPA indicates, however, that it would have certain program-design preferences aimed at ensuring accurate emissions accounting if it were to instead adopt its own compliance protocols.[40]

Section II of this report makes recommendations regarding how to structure any BSER that includes hydrogen co-firing and how to structure compliance protocols to address the risk of increased emissions from co-firing high-GHG hydrogen.

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34 *Id.* at 33,304.

35 *Id.* at 33,328 n.499 ("Well-to-gate analysis of lifecycle GHG emissions represents a smaller scope than cradle-to-grave analysis. Well-to-gate emissions of hydrogen production include those associated with fossil fuel or electricity feedstock production and delivery to the hydrogen facility; the hydrogen production process itself; and any associated CCS applied at the hydrogen production facility. Well-to-gate analysis does not consider emissions associated with the manufacture or end-of-life of the hydrogen production facility or facilities providing feedstock inputs to the hydrogen production facility. Nor does it consider emissions associated with transportation, distribution, and use of hydrogen beyond the production facility.").

36 *Id.* at 33,310.

37 26 U.S.C. § 45V(b)(2)(D), (c)(1).

38 Proposed Rule, 88 Fed. Reg. at 33,328.

39 Treasury Proposed Rule, *supra* note 8.

40 Proposed Rule, 88 Fed. Reg. at 33,329.

II. Designing EPA's Final BSERs and Verification Protocols to Ensure Climate Benefits

Consistent with the purpose of Section 111 of the CAA, EPA should structure the final rule to support net GHG emission reductions from hydrogen co-firing. First, EPA should finalize its proposal to specify that any hydrogen co-firing-based BSERs are premised on burning low-GHG hydrogen. Second, EPA should make decisions regarding administrative severability based on the ultimate goal of GHG reduction. Third, EPA should adopt verification protocols similar to those proposed by the Department of Treasury that provide reasonable criteria for evaluating whether hydrogen has met the emission limit set by the BSER. Fourth, because EPA may finalize BSERs for some subcategories of turbines based on CCS rather than hydrogen co-firing,[41] EPA should act to ensure that operators do not co-fire with high-GHG hydrogen when complying with these CCS-based standards of performance.

A. Specifications for Hydrogen Co-Firing in the BSER

To ensure that the use of hydrogen co-firing yields maximum climate benefits, EPA should include a low-GHG limitation in the BSERs for any hydrogen subcategory. And, when deciding whether to make the low-GHG hydrogen limitation severable from the other components of the applicable BSERs, EPA should consider the likelihood that, absent a low-GHG limitation, a hydrogen subcategory would aggravate climate change instead of mitigating it. If there is a substantial likelihood that, without a low-GHG limitation, the BSER for a hydrogen subcategory would still reduce emissions relative to the status quo, EPA should consider making the low-GHG limitation severable.

1. The Low-GHG Hydrogen Limitation

Despite EPA's recognition that co-firing with high-GHG hydrogen would undercut the climate benefits of reducing CO_2 emissions at power plants, it asks whether finalizing a low-GHG limitation in a hydrogen co-firing BSER would be unnecessary.[42] EPA raises the possibility that federal incentives and industry trends may themselves be sufficient to ensure that low-GHG hydrogen dominates the market when the hydrogen-related provisions begin to apply in 2032.[43]

The answer is likely no. EPA's original proposal to include the low-GHG hydrogen limitation would better ensure the rule's climate benefits because, without this safeguard, it is possible that generators would comply by co-firing high-GHG hydrogen.

Of the multiple ways to produce hydrogen, only electrolysis powered by renewables or nuclear has a carbon intensity less than EPA's proposed definition for "low-GHG hydrogen" of <0.45 kg CO_2e/kg H_2 from well to gate.[44] The next cleanest production method—steam methane reforming (SMR) with CCS—has a carbon intensity of approximately 4.6 kg CO_2e/kg H_2 when the CO_2 capture rate is 96.2%.[45] These emissions represent a combination of CO_2 released directly

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[41] *See supra* Section I.A.

[42] Proposed Rule, 88 Fed. Reg. at 33,310–11.

[43] *Id.* at 33,311.

[44] DOE Commercial Liftoff, *supra* note 9, at 10 fig.2.

[45] Dep't of Energy, Hydrogen Shot Technology Assessment 12, 19–20 (2023) [hereinafter DOE Technology Assessment], https://perma.cc/84CW-49X9.

during SMR, upstream emissions of the methane feedstock, and the electricity emissions from running the CCS.[46] Without CCS, SMR has a carbon intensity of about 10–12 kg $CO_2e/kg\ H_2$.[47] Using fossil fuels to power electrolysis is even more emissions-intensive: 22–24 kg $CO_2e/kg\ H_2$ for natural gas (without even accounting for upstream methane emissions) and 51–56 kg $CO_2e/kg\ H_2$ for coal.[48]

In 2022, approximately 95% of hydrogen was produced via SMR without CCS (or similar processes based on methane and also without CCS).[49] Less than 5% was produced through SMR with greater than 90% CCS.[50] Less than 1% of hydrogen was produced via electrolysis powered by zero-emissions resources.[51] Although these percentages should change as the costs of CCS and electrolysis drop due to learning-by-doing and federal subsidies, there is no consensus that zero-emissions electrolytic hydrogen will become cheaper than SMR hydrogen without CCS by 2032 (even though it is already competitive for certain projects in certain locations).[52] And, according to one analysis of proposed projects, more than two-thirds of hydrogen production capacity slated to come online is fossil-based.[53] Further, according to the White House, only two-thirds of the recent $7 billion proposed federal investment in hydrogen hubs is "associated" with electrolytic hydrogen.[54] These statistics suggest that it would premature to assume that the problem of hydrogen's lifecycle emissions will be solved by 2032 such that a low-GHG limitation would be redundant.

Modeling from DOE further supports specifying low-GHG hydrogen as a component of the BSERs. Although the IRA incentivizes investment in electrolytic hydrogen with relatively few lifecycle emissions, DOE's modeling indicates that gas-fired turbines are far from guaranteed to co-fire with this cleanest category of hydrogen in 2032 and after.[55] While DOE predicts that electrolytic hydrogen will largely outcompete SMR hydrogen with CCS in 2030 and comprise 70–95% of the market then, DOE also predicts increasing penetration of SMR hydrogen with CCS in the 2030s and 2040s.[56] In 2040, DOE expects SMR hydrogen with CCS to comprise 50–70% of total U.S. hydrogen production, with electrolytic hydrogen being the other 30–50%.[57] For 2050, DOE predicts a similar breakdown.[58] Given that SMR hydrogen with

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[46] *Id.* at 19–20.

[47] *Id.*

[48] *See* Thomas Koch Blank & Patrick Molly, RMI, Hydrogen's Decarbonization Impact for Industry 5 (2020), https://perma.cc/T3XH-9DSQ ("Producing one kilogram of hydrogen with electrolysis requires 50–55 kWh of electricity. This power consumption leads to indirect CO_2 emissions, the level of which varies according to the sources of electricity used."); *Frequently Asked Questions*, Energy Info. Admin., https://perma.cc/6DJ6-2C77 (providing the CO_2 intensity per kWh for natural gas and coal plants).

[49] DOE Commercial Liftoff, *supra* note 9, at 10 at 10 fig.2.

[50] *Id.*

[51] *Id.*

[52] Ben King et al., Rhodium Group, How Clean Will US Hydrogen Get? Unpacking Treasury's Proposed 45V Tax Credit Guidance (Jan. 4, 2024), https://perma.cc/766H-F83D ("If clean hydrogen is going to play a major role in the US energy system, it first needs to be competitive with conventional natural gas-derived hydrogen, which currently costs $1-$1.50/kg, a price that varies largely based on the price of natural gas. . . . Most estimates are generally in the $4-$6/kg range, though some geographies and configurations yield estimates in the sub-$3/kg range. If these projects can qualify for the full $3/kg 45V credit, the post-subsidy cost of this hydrogen could very easily be at or below current fossil hydrogen prices."); Clean Air Task Force et al., *supra* note 26, at 203–04 ("EPA projects that low-GHG hydrogen production costs will to fall to $0.40/kg by 2030 while the delivered cost to the turbine will range from $0.70/kg to $1.15/kg. This projection is highly optimistic and actual costs, per our projections and calculations, for low-GHG hydrogen are unlikely to fall below $5/kg, or $2/kg when subsidized with the 45V production tax credit."); Kamala Schelling, *Green Hydrogen to Undercut Gray Sibling by End of Decade*, BloombergNEF (Aug. 9, 2023), https://perma.cc/M6M7-RWMH (forecasting that SMR hydrogen without carbon capture will remain cheaper than electrolytic zero-emissions hydrogen in 2030).

[53] Env't Def. Fund et al., Petition for Rulemaking to List and Establish National Emission Standards for Hydrogen Production Facilities under Clean Air Act Sections 111 and 112 at 24–25 (Sept. 15, 2023) [hereinafter EDF Rulemaking Petition], https://perma.cc/N9MF-BJBA.

[54] *Biden-Harris Administration Announces Regional Clean Hydrogen Hubs to Drive Clean Manufacturing and Jobs*, The White House (Oct. 13, 2023), https://perma.cc/Y6R2-7SHB.

[55] DOE Commercial Liftoff, *supra* note 9, at 37 fig.15.

[56] *Id.*

[57] *Id.*

[58] *Id.*

CCS can have a GHG intensity of more than ten times the emissions of EPA's proposed threshold of <0.45 kg CO_2e/kg H_2,[59] these results suggest the usefulness of a low-GHG limitation to ensure emission reductions.

For the above reasons, EPA should specify that any hydrogen co-firing BSER is predicated on burning only low-GHG hydrogen.[60] The absence of such a limitation may blunt the climate benefits of the Proposed Rule—or even have the perverse effect of causing a net increase in GHG emissions relative to the status quo.[61]

Beyond the threat of high-GHG hydrogen, co-firing with *hydrogen* associated with significant hydrogen emissions could also prove counterproductive.[62] Hydrogen emissions occur throughout the entire value chain (production, conversion, transportation, distribution, storage, and end-use), both intentionally (operational purging and venting) and accidentally (leakage).[63] Although hydrogen is only an *indirect* GHG,[64] one recent study estimated the GWP20 of hydrogen at 37.3, indicating that hydrogen causes 37.3 times as much warming over a 20-year period as an equal mass of CO_2.[65] If co-fired hydrogen were associated with a hydrogen emissions rate of 1.2%, the hydrogen emissions by themselves would be the equivalent of 0.45 kg CO_2/kg H_2.[66] One survey of the literature reports that hydrogen can leak or be released intentionally throughout the value chain, and total estimates range from 0.2% to 20%.[67]

EPA should therefore consider whether to define "low-GHG hydrogen" to specify limited hydrogen emissions. To the extent that EPA has any legal concerns about addressing these emissions within this rulemaking, the agency could make this aspect of the rule legally severable, as discussed in Section II.A.2. If EPA does not incorporate a hydrogen-emission limit into the definition of "low-GHG hydrogen," it would be especially important for the agency to work expeditiously toward a Section 111 rulemaking to regulate hydrogen emissions from hydrogen infrastructure, and for PHMSA to specifically address the detection and repair of hydrogen leakage from pipelines. We discuss both options in Section III.

2. *Severability of the Low-GHG Hydrogen Limitation*

In the Proposed Rule, EPA asks whether the final rule should state that the low-GHG hydrogen limitation is legally severable from the other components of any hydrogen subcategory.[68] In other words, should the hydrogen co-firing BSERs

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59 DOE Technology Assessment, *supra* note 45, at 19–20.

60 *See also* EPA Sci. Advisory Bd., Draft Review of the Science Supporting the Proposed Rule Titled, 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– 15 AV09) at 14 (2024), https://sab.epa.gov/ords/sab/f?p=114:0:11333018855482:APPLICATION_PROCESS=DRAFT_REPORT:::DR_ID:427 ("Finding: The SAB affirms the necessity of a low-GHG hydrogen definition in the proposed rule 31 and recommends that this definition appear before references to that term within the rule.").

61 *See* Proposed Rule, 88 Fed. Reg. at 33,315 ("Co-firing hydrogen at combustion turbines when that hydrogen is produced with large amounts of GHG emissions would ultimately result in increasing overall GHG emissions, compared to combusting solely natural gas at the combustion turbine.").

62 EPA Sci. Advisory Bd., *supra* note 60, at 10–11 ("While hydrogen is not included in the list of greenhouse gases currently considered by the EPA, its indirect effects on climate are significant.").

63 Sofia Esquivel-Elizondo et al., *Wide range in estimates of hydrogen emissions from infrastructure*, 11 Frontiers in Energy Rsch. 1, 3–4 (2023).

64 Because hydrogen is not technically a GHG (despite its ability to induce warming), if EPA were to impose a limitation on hydrogen emissions, EPA might describe compliant hydrogen as "low-emissions hydrogen" or "low CO_2e hydrogen," rather than "low-GHG hydrogen."

65 Maria Sand et al., *A Multi-Model Assessment of the Global Warming Potential of Hydrogen*, 4 Commc'ns Earth & Env't 1, 5 (2023).

66 Using hydrogen's GWP100 of 11.6, *id.* at 1, an emissions rate of 3.9% would be the equivalent of 0.45 kg CO_2/kg H_2.

67 Esquivel-Elizondo et al., *supra* note 63, at 5.

68 Proposed Rule, 88 Fed. Reg. at 33,316 ("[T]he EPA also solicits comment as to whether the low-GHG hydrogen requirement could be treated as severable from the remainder of the standard such that the standard could function without this requirement."). Note that this is a distinct issue from whether requirements for each subcategory should be severable from the rest of the rule.

persist if a court rejects EPA's authority to specify the use of low-GHG hydrogen? Such a circumstance would open the door for plant operators to comply with the rule's hydrogen-related provisions by co-firing with any hydrogen. EPA's received comments arguing for[69] and against[70] EPA's authority to include a low-GHG limitation.

As we previously summarized in our comments on the Proposed Rule, EPA's consideration of the emissions associated with hydrogen production is consistent with its longstanding practice of considering a BSER's offsite effects.[71] Such an approach is supported by statutory requirement to achieve the "best" system of emission reductions, which the D.C. Circuit recognized has the legislative purpose to maximize emission reduction as much as practicable.[72] In the Proposed Rule, EPA documents its historical reliance on lower-emitting fuels as the BSER in other CAA Section 111 rules as additional support for its approach.[73]

Recent case law is consistent with this historical perspective. In *American Lung v. EPA*, the D.C. Circuit clarified that the CAA "does not . . . constrain the Agency to identifying a best system of emission reduction consisting only of controls 'that can be applied at and to a stationary source.'"[74] In *West Virginia*, the Supreme Court reversed that decision on other grounds (the impermissibility of generation shifting as a BSER), but expressly reserved judgment on the fenceline issue. The Court explicitly stated: "We have no occasion to decide whether the statutory phrase 'system of emission reduction' refers *exclusively* to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as the BSER."[75]

Leaving further discussion of the fenceline debate for other venues, EPA's choice concerning severability should be informed by the immediately preceding discussion of why EPA should design the BSER around low-GHG hydrogen: This rule's climate impact is highly sensitive to the emissions profile of the co-fired hydrogen, and EPA should not expect low-GHG hydrogen to be as widely used absent a low-GHG limitation.[76] Given these conditions, EPA should either carefully explain why hydrogen co-firing would qualify as a BSER for GHG emissions even if the hydrogen were not required to be low GHG or specify that the low-GHG limitation is inseverable.

To decide whether hydrogen co-firing can be considered a BSER even absent a low-GHG hydrogen specification, EPA should focus on the risk that the hydrogen co-firing BSERs would cause a net climate harm if there were no restrictions on the emissions intensity of co-fired hydrogen. The Proposed Rule correctly recognizes that such harm would be contrary to Section 111 because "creat[ing] more damage (in the form of GHG emissions) than [a rule] prevented" would, ironically, cause "the precise problem CAA Section 111 is intended to address."[77]

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69 *E.g.*, Sierra Club et al., Comments on Proposed Rule 61–64 (Aug. 8, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0813.

70 *E.g.*, Edison Elec. Inst., Comments on Proposed Rule 156–59 (Aug. 16, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0772.

71 Inst. Pol'y Integrity, Comments on Proposed Rule 12 (Aug. 8, 2023), https://perma.cc/PNE8-67WD.

72 Sierra Club v. Costle, 657 F.2d 298, 325–26 (D.C. Cir. 1981) ("We find this position [that EPA may not consider total air emissions in deciding on a proper NSPS] untenable given that one of the agreed upon legislative purposes . . . requires that the standards must maximize the potential for long term economic growth 'by reducing emissions as much as practicable.' . . . [W]e can think of no sensible interpretation of the statutory words 'best technological system' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling sulfur dioxide emissions. Control technologies cannot be 'best' if they create greater problems than they solve.").

73 Proposed Rule, 88 Fed. Reg. at 33,315.

74 Am. Lung Ass'n v. EPA, 985 F.3d 914, 944 (D.C. Cir.), *rev'd and remanded on other grounds sub nom. West Virginia*, 597 U.S. 697.

75 *West Virginia*, 597 U.S. at 734.

76 *See supra* Section II.A.1.

77 Proposed Rule, 88 Fed. Reg. at 33,315.

If electing to make any component of the rule severable, EPA should provide an explanation for why the rule can function without the severable section. Boilerplate language labeling an aspect of a rule as severable does not necessarily make it so in the eyes of a court.[78] For a court to find a regulation severable, there cannot be "substantial doubt" that the agency would have promulgated the remainder of the regulation by itself, and the surviving regulation must "function sensibly" on its own.[79]

Accordingly, when EPA makes a decision regarding severability of the low-GHG limitation, EPA should be careful to explain how it arrived at that result through consideration of the statutory factors (emission reductions, costs, etc.). If EPA concludes that the first-best system of emission reduction for a unit is hydrogen co-firing with a requirement to use low-GHG hydrogen but that—if that option were removed by a court—the next-best system of emission reduction would be hydrogen co-firing using any hydrogen, then EPA should explain this and classify the low-GHG limitation as severable. If EPA reaches a contrary conclusion—that the BSER for a unit would not be hydrogen co-firing if the low-GHG hydrogen requirement were set aside—then EPA should say this instead and classify the requirement as inseverable.[80]

A key factor influencing the risk of net climate harm absent a low-GHG limitation will be what additional actions EPA and other federal agencies take to address hydrogen's lifecycle emissions beyond this rulemaking (as described in Section III). If implemented, these options could help compensate for the lack of a low-GHG limitation, so their availability may enable a hydrogen co-firing BSER to result in net decarbonization even if the low-GHG limitation were set aside by a court or never finalized by EPA. For example, if Treasury were to finalize its proposed rule implementing the clean hydrogen production tax credit and EPA were to promulgate GHG standards of performance for fossil-based hydrogen-production facilities, these actions could together significantly reduce the lifecycle emissions of hydrogen by 2032.

In short, EPA's decision on severability should ultimately depend on whether allowing a generator to co-fire with any hydrogen would result in emission reductions at power plants that more than offset any corresponding increase in hydrogen-production emissions. The answer to this question may, in turn, depend on other regulations that reduce the lifecycle emissions of hydrogen.

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78 Adelaide Duckett & Donald L. R. Goodson, Inst. For Pol'y Integrity, Administrative Severability: A Tool Federal Agencies Can Use to Address Legal Uncertainty (2023); Nasdaq Stock Mkt. LLC v. SEC, 38 F.4th 1126, 1145 (D.C. Cir. 2022) ("'[T]he ultimate determination of severability will rarely turn on the presence or absence' of a severability clause." (quoting Cmty. for Creative Non-Violence v. Turner, 893 F.2d 1387, 1394 (D.C. Cir. 1990))).

79 *Nasdaq*, 38 F.4th at 1144 (first quoting Epsilon Elecs., Inc. v. Dep't of Treasury, 857 F.3d 913, 929 (D.C. Cir. 2017); and then quoting Carlson v. Postal Regul. Comm'n, 938 F.3d 337, 351 (D.C. Cir. 2019)).

80 As discussed in Section I.A, EPA proposes dual-pathway BSERs for new baseload natural gas turbines, allowing them to select between standards based on hydrogen co-firing or CCS. If EPA declines to adopt commenters' recommendations to finalize only single-pathway BSERs, then the presence of the dual-pathway BSERs will become a significant factor as EPA considers severability. In the case of a *dual-pathway BSER*, inseverability of the low-GHG requirement from the hydrogen co-firing BSER could be more effective for achieving emission reductions, as these sources would still be subject to an alternative CCS-based BSER. Whereas, if the dual BSER subcategories allowed the requirement to use low-GHG hydrogen to be severable, and it were subsequently severed, this would potentially create a loophole for emissions increases under the hydrogen co-firing pathway relative to the CCS pathway. In the case of a subcategory for which hydrogen co-firing is the *single-pathway BSER*, if the definition of low-GHG hydrogen were inseverable, and the hydrogen co-firing BSER were struck down, it could result in these sources needing to comply with only the Proposed Rule's phase 1 standards, which are best practices for operating and maintenance. However, if the definition were severed, plants could comply by co-firing any hydrogen, which may or may not be better than simply burning natural gas, depending on the emissions intensity of the co-fired hydrogen and the hydrogen emissions. Accordingly, EPA should weigh whether to describe the hydrogen co-firing BSER as severable for some units (e.g., single-pathway BSERs) but not others (e.g., dual-pathway BSERs if EPA finds that emissions intensity of hydrogen would be sufficiently low).

B. Verification Protocols for Compliance with a Hydrogen Co-Firing BSER

No matter how well designed, the hydrogen co-firing BSERs will be only as good as EPA's regime to measure emissions and certify compliance with the associated performance standards. Here, we tackle a particularly thorny aspect of this emissions accounting: calculating the production emissions from grid-connected electrolysis (i.e., the emissions from the electric grid when an electrolyzer uses grid power to split water into hydrogen and oxygen). There is significant risk that a poorly designed verification regime for electrolytic hydrogen would substantially underestimate hydrogen-production emissions, jeopardizing the rule's GHG pollution-reduction goals. This could happen if EPA allows emissions-accounting maneuvers that mistakenly classify electrolytic hydrogen as "low GHG" when the electricity comes from burning natural gas. Co-firing with this hydrogen would cause significantly more GHG emissions than simply burning natural gas in the turbine.

As already discussed in Section I.B, EPA has proposed to adopt the emissions-accounting protocols promulgated by Treasury for the clean hydrogen production tax credit,[81] but EPA also solicits comment on whether it should create its own verification protocols.[82] The Proposed Rule indicates that, if EPA develops its own protocols, it would prefer robust ones that prioritize accuracy.[83] Since the publication of the Proposed Rule, Treasury has released its proposal, which would require incrementality, a transition to hourly matching, and deliverability[84]—each of which would help ensure accurate measurement of production emissions, as explained below. If Treasury finalizes a rule that substantially resembles Treasury's proposal, EPA should adopt it because it reflects strong emissions-accounting practices consistent with the design elements that EPA indicated it would prefer.[85] But if Treasury finalizes a rule significantly weaker than its proposal, EPA should develop its own protocols that would avoid misclassifying high-GHG hydrogen as low-GHG hydrogen.

1. EPA Should Adopt Treasury's Verification Protocols If the Final Version Substantially Resembles the Proposal

Treasury's proposed rule for the clean hydrogen production tax credit would allow electrolyzers to demonstrate their emissions intensity by purchasing Energy Attribute Certificates (EACs) that represent the emissions intensity of a unit of electricity.[86] To qualify for use, the EACs must satisfy the three principles of incrementality, annual matching with a transition to hourly matching, and deliverability.[87] Incrementality refers to EACs generated by an incremental source of low-GHG electricity, such as a newly built generation facility, rather than renewable energy that would have been produced and used by another source without the rule.[88] Annual matching and hourly matching each refer to the allowed distance in time between the accrual of the EAC and the electrolyzer's use of electricity.[89] And deliverability refers to whether the electricity associated with the EAC can physically reach the electrolyzer given their respective locations within the transmission network and congestion.[90]

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81 Proposed Rule, 88 Fed. Reg. at 33,328.
82 *Id.* at 33,329.
83 *See id.* at 33,331.
84 Treasury Proposed Rule, *supra* note 8, at 89,228.
85 *See* Proposed Rule, 88 Fed. Reg. at 33,331.
86 Treasury Proposed Rule, *supra* note 8, at 89,227.
87 *Id.* at 89,228.
88 *Id.*
89 *Id.*
90 *Id.*

When an electrolyzer purchases EACs from low-GHG generators that satisfy these principles, we can be confident that the resulting hydrogen will be low-GHG. Accordingly, if Treasury finalizes these requirements (and does not create exceptions that undermine them), it would be reasonable for EPA to adopt Treasury's verification protocols.

a. Incrementality

Treasury's incrementality requirement aims to prevent the problem of electrolyzers using EACs to appear "clean" on paper while actually inducing substantial grid emissions.[91] Imagine a new electrolyzer comes online and contracts for EACs from a renewable resource that was producing electricity (and possibly EACs) for a different customer. The electrolyzer would have added new load to the system without adding any new clean generation. If the electrolyzer operates when renewables aren't being curtailed, its incremental demand would likely be met through fossil generation that otherwise wouldn't have occurred—just as if the electrolyzer had directly contracted with those fossil generators. This is because of the merit-order dispatch of generation resources, which generally causes any renewable resources to be dispatched before fossil generation, in light of their respective operating costs.[92]

Stated rigorously, true incrementality means showing that the associated clean generation would not have been deployed but for the revenue from selling EACs to the associated electrolyzer.[93] But demonstrating incrementality with this level of rigor is challenging, given the difficulty of proving a counterfactual. Treasury proposes an easy-to-implement heuristic that incrementality would be satisfied if the generator began its commercial operations no earlier than three years before the electrolyzer was placed into service.[94] An electrolyzer could also contract with existing plants that have been uprated (i.e., enlarged) if the uprate occurred no earlier than three years before the electrolyzer was placed into service and the purchased electricity comes from the uprated production.[95] The primary virtue of Treasury's proposal is that, intuitively, generators built more than three years prior to the production of EACs are unlikely to have required EAC-based revenue to cover project costs, and are therefore more likely to be incremental.

b. Hourly Matching

Treasury would place timing restrictions on EAC purchases that electrolyzers can use to qualify for the tax credit—specifically, how close in time the production of the electricity associated with the EACs must be compared to the electrolyzer's consumption of power. Until the end of 2027, electrolyzers could establish the emissions intensity of their hydrogen by contracting for EACs that accrue within the same *year* as the hydrogen was produced.[96] Starting in 2028, the EACs

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[91] Dep't of Energy, Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit 9 (Dec. 22, 2023), https://perma.cc/AE6X-UYNU [hereinafter DOE White Paper] ("[C]onsider EACs that are geographically and temporally matched to the buyer's load but do not come from sources of incremental generation. . . . The overall load on the system is increased due to the buyer's new load but that increase is not compensated by an increase in new supply from the generator selling the EACs—thus requiring other existing generations (e.g., GHG emitting dispatchable generators such as natural gas or coal) to supply the overall increase in load immediately . . . . This demonstrates that the absence of an incremental generation attribute would yield an inaccurate assessment of induced grid GHG emissions from the incremental hydrogen load.").

[92] Nat'l Ass'n of Clean Air Agencies, Implementing EPA's Clean Power Plan: A Menu of Options 21-1 to 21-2 (2015), https://perma.cc/MET8-Y2DD ("With all of the information on capabilities and costs in hand, the system operator then ranks the available [electric generating units (EGUs)] in merit order from the least costly to the most costly . . . . Ideally the system operator would want to minimize the costs of meeting electric demand by scheduling EGUs for dispatch based on merit order. The least costly EGU would be scheduled first, and then the next least costly EGU, and so forth until enough generation was scheduled to meet the expected demand.").

[93] *Cf.* Gov't Accountability Off., GAO-11-345, Options for Addressing Challenges to Carbon Offset Quality 3 (2011), https://perma.cc/6FUU-ZEG6 ("An offset is additional if it would not have occurred without the incentives provided by the offset program.").

[94] Treasury Proposed Rule, *supra* note 8, at 89,229.

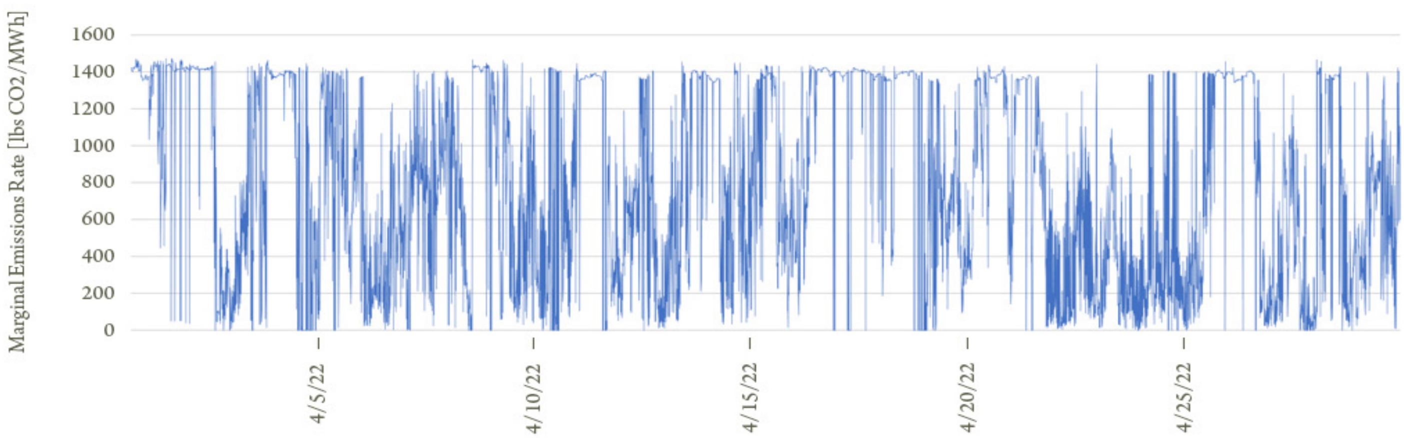
[95] *Id.*

[96] *Id.* at 89233–34.

would need to accrue within the same *hour* as the hydrogen.[97] It is necessary to understand some basics about the electric grid to see how this transition to hourly matching would increase the accuracy of Treasury's verification protocols and thus better distinguish between low- and high-GHG hydrogen.

Given the realities of grid operation, the most accurate way to measure emissions from grid-connected electrolyzers involves looking at the emissions intensity of the "marginal" generator serving the local grid at the moment of hydrogen production. The marginal generator is whichever generator the grid operator would ask to increase its output to meet additional demand for electricity. The identity of the marginal generator—and thus the marginal generator's emissions intensity—changes frequently throughout the day. Figure 2—which depicts the marginal emissions rate in the Southwest Power Pool (a regional power grid in the central United States) and which was generated by WattTime—reveals that the marginal emissions rate can swing back and forth from zero lbs CO_2/MWh to over 1,400 lbs CO_2/MWh repeatedly throughout a single day.[98] DOE also recognizes the significant temporal variation in marginal emissions rates.[99]

Figure 2: Marginal Emissions Rates in Southwest Power Pool for April 2022



Because the emissions from the marginal resource would be avoided if the electrolyzer did not run, load from the electrolyzer causes the emissions of this marginal generator in real time. This point has a corollary: Because grid operators generally deploy clean resources like renewables and nuclear before resources with fuel costs, incremental generation from these resources allows a marginal fossil generator to ramp down and thus avoids emissions from the marginal generator. Finally, the resource producing EACs may or may not have its own emissions rate, depending on whether it is a zero-emissions resource like a solar farm or a less-emitting resource like a natural gas plant with CCS. These ideas lead to this critical point: When the marginal emissions rates during electricity consumption and EAC accrual from an incremental generator are the same, the induced emissions from electrolysis and the avoided emissions from the EAC-accruing incremental generator cancel out. The only remaining emissions associated with electrolysis are those of the EAC-accruing generator.

So, when the marginal emissions rates during electrolysis and incremental EAC accrual are the same, the emissions of the incremental EAC-accruing resource will accurately represent the emissions attributable to the hydrogen. In contrast, if an electrolyzer draws power from the grid at a time when the marginal emissions rate is higher than the marginal emissions rate when the contracted-with generator injects power, the electrolyzer induces more emissions than the generator

97 *Id.*

98 *See Methodology: How Does WattTime Calculate Marginal Emissions?*, WattTime, https://perma.cc/NTD8-F88L; WattTime, Marginal Emissions Modeling: WattTime's Approach to Modeling and Validation (2022), https://perma.cc/6DMQ-NX7P.

99 DOE White Paper, *supra* note 92, at 5 n.9. ("Several organizations have begun to report marginal operational GHG emissions rates on a regional or national basis, employing multiple methods. Research has shown significant temporal and locational variation in operation emissions rates . . . in the United States . . . . ." (citations omitted)).

avoids. In those circumstances, the hydrogen production would have a net positive emissions impact, and the emissions intensity associated with the purchased EACs would serve as a poor proxy for the hydrogen's emissions intensity.

Because the marginal resource can change so quickly and so often within a single day (see Figure 2), the emissions of the EAC-accruing generator become a worse proxy for the emissions of the electrolyzer when there is a large time gap between the electricity consumption and the incremental EAC accrual.[100] The marginal generator is less likely to change when little time has passed. Thus, requiring hourly matching would go a long way toward ensuring that electrolyzers' consumption of electricity does not cause more emissions than their EAC purchases avoid, making the emissions of the EAC-accruing generator into a usable proxy for electrolyzer emissions. But if an electrolyzer merely needs to buy EACs that accrued within the same year as the electrolyzer's power consumption, there is a significant risk that the marginal emissions rates would diverge. When the rates diverge, the EACs become a poor proxy for the emissions intensity of electrolytic hydrogen.

Although Treasury proposes to allow annual matching until 2028—at which point hourly matching would be required[101]—research suggests that the proposed transition schedule appropriately balances preventing emissions and scaling up electrolytic hydrogen. A recent study in *Nature Energy* concluded that, based on the dynamics of the renewable energy market, a transition from annual matching to hourly makes sense in approximately 2030.[102] The authors make this recommendation by balancing how each time-matching regime would affect the addition of new generation resources to the grid and thus grid-wide emissions, the effects on the levelized cost of electrolytic hydrogen (relevant for scaling the nascent industry), and the possibility that a stricter time-matching regime would lead to more methane-based hydrogen production with CCS (potentially increasing overall emissions).[103]

Another analysis concluded that transitioning from monthly matching to hourly matching in 2028 would accelerate the development of electrolytic hydrogen while causing relatively few additional emissions as compared to immediately requiring hourly matching.[104] Imposing a loose initial time-matching standard would help early movers to be cost-competitive for more end-uses and production locations.[105] Meanwhile, given the low initial volumes of electrolytic hydrogen, 95% of hydrogen produced during the lifetime of the 45V credit would be covered by hourly matching.[106]

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[100] *Id.* at 11 ("[M]ore granular, and therefore more accurate, timeframes . . . will provide significantly greater certainty about lifecycle GHG emissions outcomes by ensuring that there is actual alignment between load and generation. . . . [A]n annual matching standard means that changes in supply on a month-to-month, day-to-day, and hourly basis during the year are not necessarily matched with load over those same timeframes. That unmatched load can drive induced GHG emissions because of the significant temporal variation in grid-system GHG emissions on a monthly, daily, and even hourly basis. Given hourly changes in grid GHG emissions, an hourly energy-matching standard provides much stronger assurance that changes in load are matched by changes in supply.").

[101] Treasury Proposed Rule, *supra* note 8, at 89,233.

[102] Michael A. Giovanniello et al., *The influence of additionality and time-matching requirements on the emissions from grid-connected hydrogen production*, 9 Nature Energy 197, 204 (2024) ("[I]n the medium term (from 2030 onwards), shifting [from annual time-matching requirements] to hourly time-matching requirements may be necessary to avoid the risk of high consequential emissions impacts. Moreover, a phased approach for implementing more stringent hourly time matching may also benefit from capital cost declines for power sector resources ([variable renewable energy], battery storage) and electrolysers that would make the [levelized cost of hydrogen] outcomes for hourly time matching more compelling than values estimated here.").

[103] *Id.* at 203–04.

[104] Tessa Weiss et al., RMI, Calibrating US Tax Credits for Grid-Connected Hydrogen Production: A Recommendation, a Flexibility, and a Red Line (2023), https://perma.cc/MTU9-8HDE ("A transition to hourly matching rules creates better long-term project outcomes without stifling early-stage industry growth. A transition to hourly matching in 2028 will ensure that hydrogen production maintains long-term emissions reduction ambitions, disincentivizes projects that will be non-competitive and unsustainable in the long term, and provides necessary conditions for the United States to establish itself as a leading presence in the global hydrogen market.").

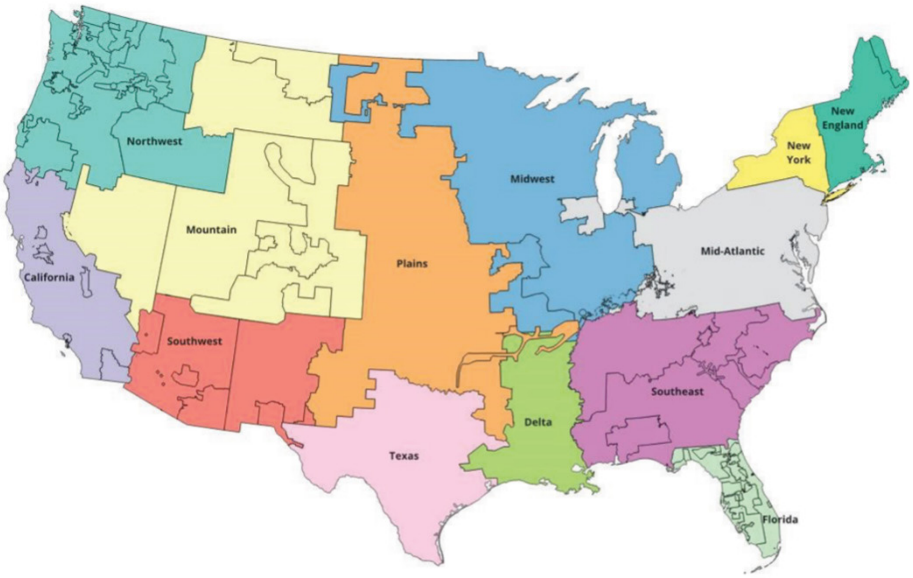
[105] *Id.*

[106] *Id.*

c. Deliverability

Treasury proposes to restrict EAC purchases to the same region to ensure deliverability.[107] Deliverability refers to whether the contracted-for EACs are associated with electricity that can flow from the generator to the electrolyzer. Electricity cannot deliverable between two regions if transmission capacity is lacking. For its deliverability regions, Treasury proposes to adopt the regions from DOE's National Transmission Needs Study, shown in Figure 3.[108] The National Transmission Needs Study documents the relative lack of transmission capacity between these regions.[109]

Figure 3: Regions from the National Transmission Needs Study[110]



As with hourly matching, this limitation is necessitated by differences in marginal emissions rates—this time, differences across space instead of time. Without deliverability, an electrolyzer might consume power in a region where the marginal resource is a fossil generator—thus inducing the emissions of that plant—while contracting for EACs with a generator located somewhere where renewables are on the margin. The result would be fossil-powered electrolysis in the first region, while the renewable generation would not avoid any emissions in the second region because renewables were on the margin there.

In other words, the absence of deliverability can create a difference between the marginal emissions rates during electrolysis and EAC accrual. As explained in Section II.B.1.b, when this happens, the emissions induced by the electrolyzer and the emissions avoided by the EAC-accruing generator don't cancel out.[111] Only when those values cancel out (and the generation is incremental) are the emissions of the EAC-accruing generator a good proxy for the emissions intensity of electrolytic hydrogen.

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[107] *Id.*

[108] Treasury Proposed Rule, *supra* note 8, at 89,233.

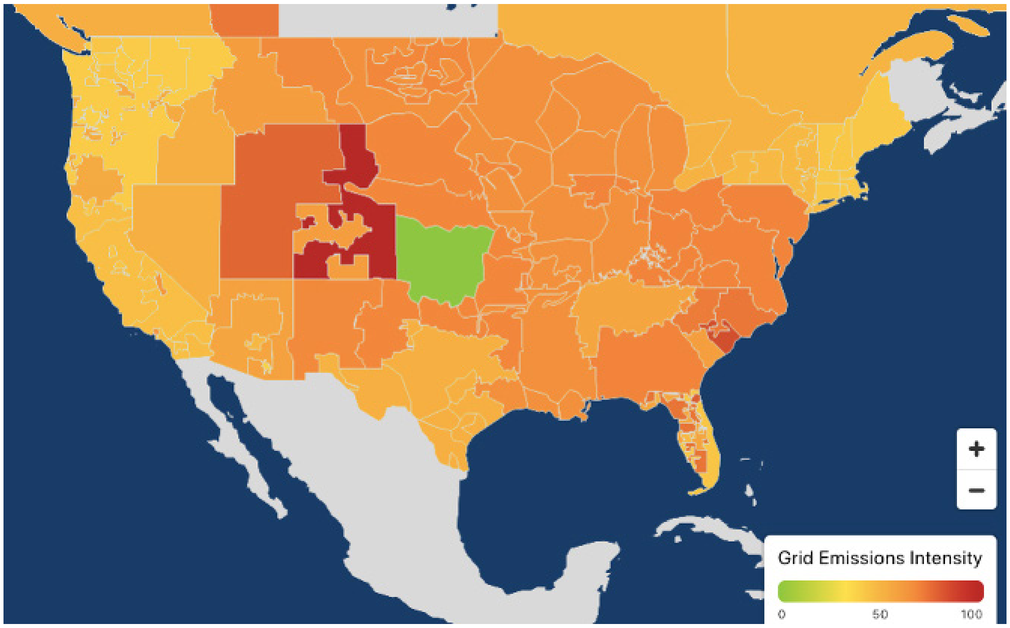
[109] Dep't of Energy, National Transmission Needs Study 131–33 tbl.IV-4 (2023) (column 2020 GW), https://perma.cc/XV2A-669T.

[110] Dep't of Energy, Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023 at 23 fig.2 (2023).

[111] *See* DOE White Paper, *supra* note 92, at 9 ("[C]onsider an example of a hydrogen producer that purchases EACs that are temporally matched and come from incremental clean generation, but without a geographic match. If the hydrogen producer operates in a grid region that is heavily dependent on high-GHG emitting generators but the clean generation operates in an otherwise low-GHG emitting region, then the net effect would be an increase in overall GHG emissions as the emissions caused by the producer would not be fully counterbalanced by the emissions displaced by the clean generation.").

Figure 4, created by WattTime based on their modeling, is a snapshot of the spatial variation in emissions rates of marginal resources on the afternoon of July 25, 2023. It shows that marginal emissions rate can diverge sharply even between two areas that are geographically proximate. The green and red areas are directly adjacent, but the lack of transmission capacity between them prevents them from sharing a single marginal generator.

Figure 4: Spatial Variability in Marginal Emissions Rates



Under Treasury's proposal, an electrolyzer in the red area could not contract with a generator in the green area because they are located in the Mountain and Plains regions, respectively. Although transmission constraints can exist within a single regional grid, Treasury's proposal to require same-region transactions is a good first approximation of deliverability.

2. *If Treasury's Final Rule Would Not Accurately Measure Hydrogen-Production Emissions from Electrolyzers, EPA Should Adopt Its Own Verification Protocols*

Treasury's proposal to require incrementality, a transition to hourly matching, and deliverability has not yet been finalized, and it is conceivable that Treasury may revise its proposed protocols in ways that reduce their accuracy.[112] If this occurs, EPA should adopt its own protocols that would accurately measure the hydrogen-production emissions from electrolyzers in order to prevent operators from co-firing with high-GHG hydrogen.

In the Proposed Rule, EPA discussed the possibility of adopting its own verification protocols and expressed a preliminary preference for hourly matching with a deliverability requirement.[113] Accordingly, if EPA needs to adopt its own protocols, it would be reasonable for it to embrace the time matching, deliverability, and incrementality requirements from Treasury's draft rule, which would have the benefits already described in Section II.B.1.

[112] *See* Nico Portuondo, *Manchin, Carper predict Biden will ease hydrogen rules*, E&E News (Jan. 12, 2024); Polly Martin, *Too strict or not enough? Draft guidance for US clean hydrogen production tax credit draws tens of thousands of comments*, Hydrogeninsight (Feb. 27, 2024).

[113] Treasury Proposed Rule, *supra* note 8, at 33,330–31.

Alternatively, EPA could preserve the deliverability and incrementality aspects of Treasury's draft rule but adopt an emissions-matching framework instead of hourly matching.[114] Under an emissions-matching framework, an electrolyzer would measure exactly how many emissions it induces. To earn the label of "low-GHG hydrogen," the electrolyzer would then reduce those emissions by purchasing EACs associated with avoided emissions. As explained in Section II.B.1.b, the emissions caused by an electrolyzer's consumption of electricity are determined by the emissions intensity of the marginal generator when and where the electrolyzer was drawing power from the grid. The electrolyzer's operations cause these emissions. And the avoided emissions of EACs are similarly determined by the emissions intensity of the local marginal generator. An incremental zero-emissions generator displaces generation from the marginal generator, which avoids the marginal generator's emissions.

So, under the emissions-matching approach, the emissions intensity of an electrolyzer's hydrogen would be the difference between (1) the emissions induced by the electrolyzer's electricity consumption and (2) the emissions avoided by the contracted-with generator supplying the EACs. (If the EACs are from a less-emitting resource like natural gas with CCS, the avoided emissions would be the avoided emissions of the marginal generator minus any emissions of the EAC-producing resource.) Hydrogen would qualify as low-GHG if the difference between those amounts satisfied EPA's definition of "low-GHG hydrogen" (e.g., <0.45 kg CO_2e/kg H_2).

The hourly matching approach roughly approximates the emissions-matching approach by assuming that marginal emissions rates remain the same over the course of a single hour.[115] If that is assumed, then the induced emissions of the electrolyzer and the avoided emissions of an incremental generator operating within the same hour will always cancel out, assuming they are on the same local grid. But, in reality, the marginal generator may change multiple times within an hour. For example, the largest U.S. grid (PJM) solves for the appropriate dispatch of the generation fleet every 5 minutes.[116] Thus, the emissions-matching approach could ensure more accurate emissions accounting than simply requiring the use and generation of electricity to occur within the same hour.

Fortunately, a marginal-emissions approach with the necessary temporal and spatial granularity for verifying the emissions intensity of co-fired hydrogen would be feasible to implement well before 2032, the first year in which the proposed hydrogen co-firing BSER would begin to apply. Most significantly, the Energy Information Administration is in the process of releasing real-time or near-real-time marginal emissions data for balancing authorities and pricing nodes.[117] When these data become available, the problem of locating accurate marginal emissions rates may be solved.

Until then, marginal emissions rates are available from private vendors,[118] as well as some grid operators like PJM.[119] Other balancing authorities publicly disclose the marginal fuel,[120] and marginal emissions rates can be derived from these

[114] *See* Letter from Clean Incentive et al. to Dep't of the Treasury et al. (May 24, 2023), https://perma.cc/VUW2-8CE8; Institute for Policy Integrity & WattTime, Supplemental Comments to U.S. Department of Treasury & Internal Revenue Service on Notice No. 2022–58 (Request for Comments on Credits for Clean Hydrogen and Clean Fuel Production) (Dec. 2, 2022), https://perma.cc/5HF2-CFW6.

[115] *See supra* Section II.B.1.b.

[116] PJM Interconnection, PJM Manual 11: Energy & Ancillary Services Market Operations 57 (Feb. 22, 2024).

[117] 42 U.S.C. § 18772(a)(2)(B) (instructing the Energy Information Administration to disseminate on a real-time basis, to the maximum extent practicable, "marginal greenhouse gas emissions by megawatt hour of electricity generated within the metered boundaries of each balancing authority" and an online database that may include the same for each node); *see also* Karen Palmer et al., Resources for the Future, Options for EIA to Publish CO_2 Emissions Rates for Electricity (2022), https://perma.cc/6VAA-JEQX.

[118] Palmer et al., *supra* note 118, at 22–25.

[119] *See Five Minute Marginal Emission Rates*, PJM Interconnection, https://dataminer2.pjm.com/feed/fivemin_marginal_emissions/definition (last visited Feb. 26, 2024); *Dispatch Fuel Mix*, ISO New England, https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/gen-fuel-mix (last visited Feb. 26, 2024) (see "marginal flag string"); see also *California Self-Generation Incentive Program*, California Public Utility Commission & WattTime, https://sgipsignal.com/ (last visited Feb. 26, 2024).

[120] *Fuel on Margin*, SPP, https://marketplace.spp.org/pages/fuel-on-margin (last visited Feb. 26, 2024); *Real-Time Fuel on the Margin*, Mid-

data using unit-specific or regional emissions factors.[121] If EPA were to require these data as part of the verification protocol, there would be more than enough lead time for market participants to stand up the necessary systems.

C. Ensuring Equivalent Stringency When Using Hydrogen Co-Firing as a Compliance Strategy

In the event that EPA finalizes rules that adopts a single CCS-based BSER for some or all subcategories of gas turbines,[122] source operators may still have the option to comply by co-firing hydrogen. As discussed above in Section I.A, BSERs are not mandates to install particular technologies or adopt particular approaches to emission reduction. Rather, they result in performance standards that require sources to achieve an equivalent level of emission reduction to what is possible under the BSER. Many of the emission-measurement challenges discussed above would also pose a problem for ensuring that compliance by hydrogen co-firing achieved equivalent emission reduction to installing CCS.

In short, a CCS-based BSER for gas turbines that allowed compliance by hydrogen co-firing without any of the above-mentioned accounting measures to ensure use of truly low-GHG hydrogen would undermine the efficacy of the final rules by allowing excess emissions (as compared to the CCS-based BSER). It would be bizarre, for example, if a natural gas unit were allowed to achieve compliance with a performance standard based on 90% CCS by co-firing hydrogen produced with electricity from burning natural gas without any CCS—a process that would result in more total emissions than burning gas directly without CCS. Given how the influx of funding under the BIL and IRA subsidies will lower the costs of co-firing hydrogen and make it a more cost-competitive compliance strategy—and how the EPA rule itself will increase demand for hydrogen—well-designed criteria for determining hydrogen co-firing achieves equivalent emission reductions as CCS would play a critical role for ensuring Section 111's pollution reduction goals.

As EPA explains in the Proposed Rule, the "reduction in CO_2 emissions achieved by a combustion turbine co-firing hydrogen is dependent on the volume of hydrogen blended into the fuel system."[123] Thus, the volume of hydrogen blended into the fuel will be a critical aspect for determining equivalency. Second, for all the reasons discussed above, this equivalency should be found only when the hydrogen used for co-firing is low-GHG hydrogen as defined and measured in a manner consistent with the recommendations contained in Section II.B. For example, it should include consideration of the emissions from co-fired hydrogen produced with grid-connected electrolyzers in line with the Treasury proposal.

Even if EPA does not include a low-GHG hydrogen limitation as part of a hydrogen co-firing BSER, or if a court were to sever a low-GHG hydrogen limitation from the BSER, EPA could still specify in its final rules that low-GHG hydrogen is necessary to demonstrate equivalent emission reduction for compliance with the performance standard by hydrogen co-firing. The co-firing of high-GHG carbon to meet a CCS-based performance standard would result in net GHG emissions far in excess of implementing CCS, a result inconsistent with Section 111's statutory purpose.[124] EPA has the

continent Independent System Operator, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Fuel%20on%20the%20Margin%20(xlsx)&t=10&p=0&s=MarketReportPublished&sd=desc (last visited Feb. 26, 2024).

121 Palmer et al., *supra* note 118, at 3–4, 7 n.3, 21–23, 41.

122 *See supra* Section I.A.

123 Proposed Rule, 88 Fed. Reg. at 33,314.

124 42 U.S.C. § 7411(b)(1)(A) (requiring EPA to regulate stationary source categories that cause, or significantly contribute to, air pollution that "may reasonably be anticipated to endanger public health or welfare" to the degree achievable after considering various factors); Pub. L. No. 91-604 § 101(b)(1), 42 U.S.C. § 1857 (1970) (showing Congress designed the Act with the broad purpose "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare"); S. Rep. No. 91-1196, at 4 (1970) (showing Congress enacted the 1970 Amendments, which included Section 111, to "provide a much more intensive and comprehensive attack on air pollution" than the previous iterations of the Act); *see also* Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations

authority to reject any State Implementation Plan that is not "satisfactory," at which point EPA could establish a federal plan.[125]

Even if EPA does not issue such a low-GHG directive for assessing equivalent emission reductions, states should choose to adopt it as part of their state plans. EPA has confirmed that states can "include standards of performance more stringent than the EPA's presumptive standards in their state plans as enforceable requirements."[126] As the 111(d) process applies to existing sources, these considerations will be most pertinent to further development and implementation of the regulations for existing gas-fired turbines.

For new sources, EPA could similarly take hydrogen-production emissions into account when determining the equivalence of hydrogen-based compliance with a CCS-based performance standard. Again, this would best achieve Section 111's statutory purpose. Section 111 standards are integrated into Title V operating permits approved by the states, and EPA can object to the issuance of those permits when they fail to meet the applicable standards in the Administrator's judgment.[127]

One technique that may help improve implementation and enforcement would be for EPA to design and define an automatically approved compliance alternative for hydrogen co-firing that meets specified standards for using low-GHG hydrogen. Such an approved alternative for existing sources could be integrated into model State Implementation Plans. For new sources, it could be outlined through directions in the final rule and EPA could also issue guidance for operating permits.[128]

Under Clean Air Act Section 111(d), 87 Fed. Reg. 79,176, 79,197 (Nov. 17, 2023) (explaining that state plans for implementing its emission guidelines for existing sources "must be consistent with the underlying statutory purpose of mitigating the air pollution emissions which endanger public health or welfare").

[125] 42 U.S.C. § 7411(d)(2)(A).

[126] Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), 88 Fed. Reg. 80,480, 80,513 (Nov. 17, 2023); 40 C.F.R. 60.24a(i)(1) ("Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing, as part of the plan: (1) Standards of performance more stringent than emission guidelines specified in this part . . .").

[127] 40 C.F.R. 70.8(c) (providing that "[n]o permit for which an application must be transmitted to the Administrator under paragraph (a) of this section shall be issued if the Administrator objects to its issuance" using a specified procedure and directing that "[t]he Administrator will object to the issuance of any proposed permit determined by the Administrator not to be in compliance with applicable requirements").

[128] EPA has issued many other guidance documents for the Title V operating permit program that could serve as models. *See Title V Operating Permit Policy and Guidance Document Index*, EPA (Oct. 16, 2023), https://www.epa.gov/title-v-operating-permits/title-v-operating-permit-policy-and-guidance-document-index (online library containing over 230 policy and guidance documents issued by EPA that help to interpret the Part 70 and 71 permit requirements).

III. Additional Policy Tools for Reducing Hydrogen's Lifecycle Emissions

While a low-GHG limitation in the final rule is one way to minimize lifecycle emissions from hydrogen co-firing, it is not the only available policy tool. EPA, Treasury, the Pipeline and Hazardous Materials Safety Administration (PHMSA), and states all have relevant authorities and responsibilities. Taking additional actions would further reduce emissions beyond what the proposed low-GHG limitation would accomplish alone. Alternatively, reducing the emissions intensity of the future hydrogen supply through these actions could take the place of a low-GHG limitation, if it were absent from the rule or severed by a court, and thus help a hydrogen co-firing BSER to accomplish decarbonization goals even without a low-GHG limitation.[129]

The section discusses policy opportunities to reduce hydrogen's lifecycle emissions, including GHG emissions from hydrogen production and hydrogen leakage emissions. Although this list is not comprehensive, we aimed to include those actions that would be most impactful (but we do not attempt to rank these items by impact). We focus exclusively on indirect and direct GHG emissions, given the scope of the Proposed Rule, but hydrogen co-firing will lead to other emissions (e.g., nitrogen oxides) that have environmental justice implications and that should receive further attention from policymakers.[130]

A. Treasury's Implementation of the Clean Hydrogen Production Tax Credit

The IRA makes four tiers of tax credits available for hydrogen production based on the well-to-gate emissions intensity of the hydrogen.[131] The largest credit applies to hydrogen with a well-to-gate emissions intensity of <0.45 kg CO_2e/kg H_2 (which became EPA's proposed definition for "low-GHG hydrogen").[132] The smallest credit applies to hydrogen with an emissions intensity of 2.5 to 4 kg CO_2e/kg H_2.[133] Given the high value of the tax credits, Treasury's decisions regarding how to measure hydrogen's well-to-gate emissions will shape the emissions intensity of future hydrogen production.

As described in Section II.B.1, Treasury's proposed approach for measuring the emissions intensity of electrolytic hydrogen would go a long way toward accurately accounting for grid emissions. As such, if Treasury were to adopt a final rule in line with its proposal, this would strongly incentivize the production of electrolytic hydrogen with almost zero production emissions from electricity. But if Treasury settles for a less robust accounting regime—e.g., a perpetual system of annual matching—Treasury would subsidize hydrogen produced with electricity from burning fossil fuels. As noted above, burning electrolytic hydrogen produced via fossil fuels causes greater climate damages than simply burning those fossil fuels, thus causing net climate harm.[134]

[129] *See supra* Section II.A.2.
[130] *See* Alastair C. Lewis, *Optimising air quality co-benefits in a hydrogen economy: a case for hydrogen-specific standards for NOx emissions*, 1 Env't Sci. Atmospheres 201 (2021).
[131] 26 U.S.C. § 45V(b)(2), (c)(1).
[132] *Id.* § 45V(b)(2)(D).
[133] *Id.* § 45V(b)(2)(A).
[134] Proposed Rule, 88 Fed. Reg. at 33,316.

B. EPA Rule for GHG Emissions from Hydrogen-Production Facilities Under CAA Section 111

In the Proposed Rule, EPA raises the possibility of initiating an additional rulemaking to regulate GHG emissions from hydrogen-production facilities under Section 111 of the CAA.[135] In September 2023, EPA received a petition to issue such a regulation for fossil-based hydrogen-production facilities.[136]

In order to issue a GHG emission limit for fossil-based hydrogen-production facilities, EPA would need to make these requisite findings and list fossil-based hydrogen production facilities as a source category. Under Section 111 of the CAA, Congress requires EPA to designate categories of stationary sources that, in the Administrator's judgment, cause or contribute significantly to air pollution that "may reasonably be anticipated to endanger public health or welfare," and then set emission limits for these sources.[137] A source category regulated under Section 111 must be comprised of "stationary source[s]," which Section 111(a) defines broadly as "any building, structure, facility, or installation which emits or may emit any air pollutant."[138] Once EPA has designated a source category under Section 111, the agency must issue regulations to control these emissions.[139]

EPA has ample evidence to support a finding that the GHG emissions from fossil-based hydrogen production facilities cause or contribute significantly to an endangerment of public health.[140] Fossil-based hydrogen production facilities in the United States already emit an estimated 90 million metric tons CO_2e emissions annually, including a single merchant facility with emissions comparable to a 300 MW coal-fired power plant.[141] This potential source category is projected to grow significantly—and so will its emissions without regulatory protections. Analysis from the Environmental Defense Fund estimates that "[a]bsent protective safeguards, the next 10 million metric tons of hydrogen production capacity added in the U.S. could add another 40 million metric tons of greenhouse gas emissions annually."[142]

Should EPA list the new source category and move forward to issuing GHG limits, it will need to select a BSER. Two BSER options for new plants are (1) electrolysis powered by zero-emissions resources that satisfies additionality, hourly matching, and deliverability or (2) maximum feasible CCS.[143] There is precedent for a BSER that completely eliminates

[135] *Id.* ("EPA may also initiate a rulemaking to regulate GHG emissions from hydrogen production under section 111 of the CAA.").

[136] EDF Rulemaking Petition, *supra* note 53.

[137] 42 U.S.C. § 7411(b)(1)(A).

[138] *Id.* § 7411(a)(3).

[139] *Id.* § 7411(b)(1)(B).

[140] EPA has previously documented its finding that GHGs endanger public health and welfare, including in the Proposed Rule. Proposed Rule, 88 Fed. Reg. at 33,249–52; *see also* Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule, 74 Fed. Reg. 66,496 (Dec. 15, 2009). As explained in its 2015 new source performance standards for EGUs, EPA finds that under the "plain language of CAA section 111(b)(1)(A)" an endangerment finding "is made with respect to the source category" rather than as to "specific pollutants." Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64509, 64530 (Oct. 23, 2015). There is no particular threshold for determining that a source category "significantly" contributes to the endangerment. *Am. Lung Ass'n*, 985 F.3d at 977 (concluding that "nothing in the Clean Air Act 'require[s] that [the] EPA set a precise numerical value as part of' a contribution endangerment finding" (alterations in original) (quoting Coal. for Resp. Regul. Inc. v. EPA, 684 F.3d 102, 122 (D.C. Cir. 2012)), *rev'd and remanded on other grounds sub nom. West Virginia*, 597 U.S. 697.

[141] EDF Rulemaking Petition, *supra* note 53, at 43.

[142] *Id.* at 2.

[143] *Id.* at 44.

emissions when the requisite technology meets the requisite statutory factors, especially for new sources.[144] For existing facilities, the petition submitted to EPA advocates for a BSER of CCS retrofitting.[145]

If such a rulemaking were to result in a strict CCS BSER for hydrogen-production facilities, and if Treasury were to finalize a proposal for the hydrogen tax credits in line with its proposal, this combination would go a long way towards reducing the lifecycle emissions of the future hydrogen supply. Together, these two actions could mitigate the need to include a low-GHG requirement in the hydrogen co-firing BSER because American-made hydrogen would have few production emissions.

C. EPA Rule for Hydrogen Emissions from Hydrogen Infrastructure Under CAA Section 111

As described in Section II.A.1, separate from hydrogen-production emissions, hydrogen is itself an indirect GHG with the potential to cause significant short-term warming. One review concludes that 4% of electrolytic hydrogen may escape during production, another 2% could escape during transportation and storage, and another 3% may leak during end-use at the turbine.[146] Some research indicates that both electrolysis and fossil-based production with CCS may cause more leakage as compared to the traditional, carbon-intensive production method of SMR without CCS.[147] Accordingly, the problem of hydrogen leakage from hydrogen-production facilities may become more acute as the hydrogen industry decarbonizes.

In accordance with the Section 111 requirements described in Section III.B, EPA could promulgate hydrogen leakage limitations for new and existing sources of hydrogen emissions.[148] Though EPA has not previously made an endangerment finding specific to hydrogen emissions, it has already listed relevant source categories.[149] Although such a rulemaking could slow the transition from fossil fuels to hydrogen co-firing, it would likely be worse from a climate perspective to engage in a massive buildout of leaky hydrogen infrastructure. And, in the long run, it may be cheaper to build this infrastructure correctly the first time, rather than retrofitting it later.

If EPA does not yet have enough information on hydrogen leakage and cannot acquire it through a request for information or advance notice of proposed rulemaking (despite the existence of a significant domestic hydrogen infrastructure, including approximately 1,600 miles of hydrogen pipelines[150]), the CAA empowers EPA to engage in the necessary fact-finding. Section 114 of the CAA grants EPA the authority to make certain demands of anyone who "may have infor-

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[144] *See* Jack Lienke et al., Inst. for Pol'y Integrity, Regulating New Fossil-Fuel Appliances Under Section 111(b) of the Clean Air Act 10 (2021) (discussing EPA's 2016 Section 111(b) standards for the oil and gas sector, which included pneumatic controllers have a zero natural gas bleed; Section 111(h) design standards for volatile-organic-compound emissions at petroleum refineries required the use of closed-purge sampling connection systems that eliminate emissions; and the text of Section 111); Andres Restrepo & Joanne Spalding, *Section 111 of the Clean Air Act and Beyond in the Aftermath of* West Virginia v. EPA, 24 Vt. J. Envtl. L. 290, 302–03 (2023) (describing examples in which "the D.C. Circuit has upheld § 111(b) rules that functionally banned certain types of facilities or operational practices at new sources in favor of environmentally superior alternatives").

[145] EDF Rulemaking Petition, *supra* note 53, at 46.

[146] Zhiyuan Fan et al., Ctr. On Glob. Energy Pol'y, Hydrogen Leakage: a Potential Risk for the Hydrogen Economy (2022), https://perma.cc/L77T-TYKG.

[147] Esquivel-Elizondo et al., *supra* note 63, at 4.

[148] *See* 42 U.S.C. § 7411(a)(3), (b)(1), (d)(1).

[149] Under Section 111, gas turbines are already a source category (40 C.F.R. 60 Subpart GG) and gas storage and transportation infrastructure is part of the oil and gas storage source category (40 C.F.R. 60 Subpart OOOO).

[150] *Hydrogen Pipelines*, Dep't of Energy, https://perma.cc/BH5K-SWB9.

mation necessary" to "assisting in the development of any . . . standard of performance under [Section 111]."[151] These include: sampling emissions in accordance when and how the Administrator prescribes, installing and using monitoring equipment, making reports, and "provid[ing] such other information as the Administrator may reasonably require."[152] EPA could use these powers to help develop the record necessary to find whether hydrogen infrastructure releases hydrogen emissions that may be reasonably anticipated to harm the public welfare and to begin identifying the appropriate BSERs if appropriate. Such a rulemaking would be more urgent if EPA omits any consideration of hydrogen leakage from its final definition of "low-GHG hydrogen."

D. Section 111 Rules for Oil and Gas Infrastructure

Because the lifecycle emissions of methane-based hydrogen depend not only on direct emissions of CO_2 but also upstream methane emissions, anything that reduces these emissions will reduce this hydrogen's emissions intensity. EPA recently issued final standards of performance and emission guidelines to control methane emissions from the oil and natural gas sector.[153] According to EPA, emissions from this sector (which include leakage from wells and other sources) amounted to 187 million metric tons CO_2e in 2019.[154] EPA estimated that its proposed rulemaking for this sector would lead to a reduction in 2032 of 130 million metric tons CO_2e.[155]

That rulemaking will make some progress towards reducing the lifecycle emissions of methane-based hydrogen production that cannot be addressed through CCS at production facilities (and thus would not be solved by promulgating a CCS-based BSER for these facilities). By continuing to strengthen these pollution limitations as new pollution control technologies and strategies emerge, EPA could continue to reduce the climate impact of methane-based hydrogen.

E. PHMSA Standards for Gas Pipelines and Pipeline Facilities, Including Hydrogen Pipelines

Under the Pipeline Safety Act, PHMSA has the authority to "prescribe minimum safety standards for pipeline transportation and for pipeline facilities" designed for "gas pipeline safety" and "protecting the environment."[156] These standards can apply to "the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities," and should consider "the particular type of pipeline transportation or facility."[157] PHMSA recently proposed to amend its regulations on leak detection and repair, with the primary goal of reducing methane emissions.[158] As with EPA's Section 111 rulemaking for the oil and natural gas sector (which does not regulate emissions from pipelines themselves), PHMSA's efforts to reduce methane emissions will reduce the lifecycle emissions of methane-based hydrogen.

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[151] 42 U.S.C. § 7414(a).

[152] *Id.* at § 7414(a)(1).

[153] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (Nov. 30, 2023), https://perma.cc/W9W6-2VAA (awaiting publication in the Federal Register).

[154] EPA, Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review 3-5 (2023), https://perma.cc/87F4-YQ5T.

[155] *Id.* at 2-57 tbl.2-9.

[156] 49 U.S.C. § 60102(a)–(b). PHSMA also has the authority to regulate transportation of hydrogen by other means, including road and rail, which may provide additional opportunities to address leakage. Austin R. Baird et al., Sandia Nat'l Lab'ys, Federal Oversight of Hydrogen Systems 11–12 (2021).

[157] 49 U.S.C. § 60102(a)(2)(B), (b)(2)(B).

[158] Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. 31,890 (proposed May 18, 2023).

PHMSA recognizes that, unless otherwise specified, its existing and proposed gas pipeline regulations "apply equally" to natural gas and hydrogen pipelines, even though hydrogen "may be particularly susceptible to leaks because of (inter alia) the smaller size of hydrogen gas molecules compared to methane molecules."[159] In PHMSA's recent proposed rule on leak detection and repair, it invited comment on "whether, within a final rule in this proceeding, there would be value in adopting hydrogen gas pipeline-specific provisions (in lieu of or in addition to the provisions proposed herein)."[160] If PHMSA were to promulgate hydrogen-specific leakage and repair regulations that account for the differences between transporting hydrogen and natural gas (whether in the ongoing rulemaking or separately), the resulting reduction in leakage would reduce the lifecycle emissions of hydrogen transported via pipelines. It would be especially important to issue these regulations before a substantial buildout of hydrogen pipelines, because, under the Pipeline Safety Act, "[a] design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted."[161]

F. State Options to Address Hydrogen's Lifecycle Emissions

States have complementary authorities to mitigate the climate harms of hydrogen co-firing by addressing hydrogen's lifecycle emissions. Because the CAA expressly does not preempt state action in this arena, states have significant latitude to address the lifecycle emissions of hydrogen.[162] The CAA's savings clause preserves states' rights to "adopt or enforce (1) any standard or limitation respecting emissions of air pollutants or (2) any requirement respecting control or abatement of air pollution," so long as it is at least as stringent as any EPA standard.[163] Accordingly, states might enact new laws to address hydrogen's lifecycle emissions, and once EPA finalizes emission guidelines for existing gas turbines, state agencies can implement more rigorous approaches through their State Implementation Plans.[164]

One possibility would be for states to require in-state fossil-based hydrogen-production facilities to install CCS. Under the CAA's savings clause, these requirements would be valid unless EPA promulgates more stringent ones for these facilities.

Second, states could demand that all (or a specified percentage of) in-state hydrogen production happen at electrolyzers that run on zero-emissions generation in accordance with incrementality, hourly matching, and deliverability. Indeed, a California bill would do exactly this by 2045 for hydrogen produced for electricity generation, with interim targets and a switch to hourly matching in 2028.[165] This approach would be somewhat analogous to state renewable portfolio stan-

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159 *Id.* at 31,899 n.75, 31,926 & n.222.

160 *Id.* at 31,926.

161 49 U.S.C. § 60104(b).

162 While the federal government possesses the limited powers enumerated in the U.S. Constitution, the Supreme Court has recognized that "[t]he States have broad authority to enact legislation for the public good—what we have often called a 'police power.'" Bond v. United States, 572 U.S. 844, 854 (2014). The Court has also reasoned that "[l]egislation designed to free from pollution the very air that people breathe clearly falls within the exercise of . . . the police power." Huron Portland Cement Co. v. City of Detroit, 362 U.S. 440, 442 (1960).

163 42 U.S.C. § 7416; City of New York v. Chevron Corp., 993 F.3d 81, 88 (2d Cir. 2021) ("While state standards must be at least as stringent as the corresponding federal requirements, states may promulgate more stringent standards if they so choose." (citing 42 U.S.C. § 7416)).

164 Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), 88 Fed. Reg. 80,480, 80,513 (Nov. 17, 2023) (explaining states can "include standards of performance more stringent than the EPA's presumptive standards in their state plans as enforceable requirements"); 40 C.F.R. 60.24a(i)(1) ("Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing, as part of the plan: (1) Standards of performance more stringent than emission guidelines specified in this part . . ."). *But see* Nat'l Ass'n of Clean Air Agencies, Restrictions on the Stringency of State and Local Air Quality Programs: Results of a Survey by the National Association of Clean Air Agencies (2014) (describing state and local limitations on adopting more stringent standards).

165 *AB-1550 Renewable hydrogen*, Calif. Legis. Info., https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240AB1550 (last visited Feb. 29, 2024); Wes Venteicher, *California hydrogen bill would impose Biden administration rules on*

dards that require electric utilities to provide a certain percentage of their power from renewable sources,[166] although the burden would be on the consuming facility to enter into the necessary contracts, rather than the utility. Placing limits on which sources of power can lawfully power electrolyzers would also resemble New York's recent law prohibiting cryptocurrency mining operations from using behind-the-meter fossil fuel-fired generation,[167] and a bill in Virginia that would require data centers to procure 90% of their electricity from renewables in order to receive a certain tax exemption.[168]

Third, states could also specify that all (or a specified percentage of) hydrogen used at in-state power plants (or at other sites) be made at electrolyzers powered by zero-emissions generation in accordance with incrementality, hourly matching, and deliverability. The California bill referenced in the prior paragraph would also impose these requirements for in-state use of hydrogen for electricity generation.[169] Such a policy would be analogous to lifecycle-emissions-focused transportation fuel standards that have been repeatedly upheld against challenges under the dormant Commerce Clause.[170]

Fourth, states could adopt codes developed by standard-setting bodies that address hydrogen safety and thus hydrogen emissions.[171] One such example of a code is the National Fire Protection Association's Hydrogen Technologies Code,[172] "which addresses several structural and safety requirements of . . . hydrogen storage facilit[ies]."[173] Requirements for safety sensors could help identify leaks and eliminate them more rapidly, increasing safety and limiting the associated hydrogen emissions.[174]

Fifth, states can implement subsidies. For example, Colorado has established a state-level tax credit for clean hydrogen based on its lifecycle emissions intensity. The tax credit considers incrementality, hourly matching, and deliverability.[175]

in-state production, E&E News (Jan. 11, 2024).

166 *See generally Renewable energy explained*, Energy Info Admin. (Nov. 30, 2022), https://perma.cc/R3NU-6CWC.

167 N.Y. Env't Conserv. Law § 19-0331 (prohibiting the approval of air pollution permits for behind-the-meter fossil fuel-fired generation used for cryptocurrency mining).

168 *HB 116 Retail Sales and Use tax; exemption for data centers*, Va.'s Legis. Info. Sys., https://lis.virginia.gov/cgi-bin/legp604.exe?241+sum+HB116 (last visited Feb. 29, 2024); Joe Burns, *Virginia lawmaker proposes data center efficiency bill, possibly affecting Dominion Energy*, UtilityDive (Jan. 8, 2024).

169 *See supra* note 166.

170 *See* Rocky Mountain Farmers Union v. Corey, 913 F.3d 940 (9th Cir. 2019); Am. Fuel & Petrochemical Manufacturers v. O'Keeffe, 903 F.3d 903 (9th Cir. 2018); Rocky Mountain Farmers Union v. Corey, 730 F.3d 1070 (9th Cir. 2013); *see also* Nat'l Pork Producers Council v. Ross, 598 U.S. 356 (2023) (upholding a state law that limited the sale of pork from pigs raised in a cruel manner).

171 Baird et al., *supra* note 157, at 9–10.

172 *NFPA 2, Hydrogen Technologies Code*, Nat'l Fire Prot. Ass'n, https://www.nfpa.org/product/nfpa-2-code/p0002code (last visited Mar. 1, 2024).

173 Baird et al., *supra* note 157, at 10.

174 *Safety, Codes, and Standards*, Nat'l Renewable Energy Lab'y, https://perma.cc/B8DY-844J.

175 Colo. Rev. Stat. §§ 39-22-557(3)(a), 40-2-138(3)(b)(I); *see also* Will Toor, *A new Colorado law makes it a top site for clean hydrogen developers, but it's not a model for federal rules*, UtilityDive (May 25, 2023).

IV. Conclusion

Hydrogen co-firing at power plants can help achieve decarbonization—if done right. A holistic approach to limiting and measuring the lifecycle emissions of hydrogen is necessary to prevent a situation in which the climate benefits of CO_2 reductions at power plants are partially or fully offset by direct GHG emissions and hydrogen emissions from hydrogen production. By finalizing a low-GHG limitation as part of the BSER, EPA can ensure a regulatory regime consistent with Section 111's statutory purpose to reduce pollution that endangers public health and the environment. Accurate protocols for measuring hydrogen's emissions intensity will be a necessary component to make the limit effective in practice. For electrolytic hydrogen, it would be wise for EPA to adopt Treasury's proposed trifecta of incrementality, phased-in hourly matching, and deliverability. These protocols can also help with measuring compliance via hydrogen co-firing for subcategories with CCS-based BSERs. Without such attention to assessing the equivalency of compliance options, EPA risks increased GHG emissions relative to the BSER.

If EPA believes that hydrogen co-firing without a low-GHG limitation in the BSER would still cause a net reduction of GHG emissions for the hydrogen subcategories, EPA should make the limitation severable. Particularly in the absence of a low-GHG limitation in the BSER, EPA and other regulators' use of additional tools to control hydrogen's production and leakage emissions will also influence the net climate impact of hydrogen co-firing. Collectively, a set of policies affecting hydrogen's emissions throughout its lifecycle could potentially allow the Proposed Rule's hydrogen co-firing provisions to mitigate climate change even without the low-GHG limitation.

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