UNITED STATES INTERNAL REVENUE SERVICE

Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property	)	**Docket ID No. IRS-2023-0066**
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88 Fed. Reg. 89,220 (Dec. 26, 2023)	)	

COMMENTS OF EARTHJUSTICE AND SIERRA CLUB ON THE NOTICE OF PROPOSED RULEMAKING

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I. INTRODUCTION

The U.S. Department of the Treasury ("Treasury") has the critical task of ensuring hydrogen producers do not receive transformational federal tax credits under Internal Revenue Code Section 45V ("45V") unless they meet the lifecycle greenhouse gas ("GHG") emissions thresholds set by Congress. Treasury cannot accomplish this task without requiring careful carbon accounting that accurately captures the real-world emissions impacts of hydrogen production. In its provisions for electrolytic hydrogen, Treasury's notice of proposed rulemaking ("Proposed Rule")[1] goes a long way toward requiring exactly that. The rules for electrolytic hydrogen should be finalized without amendments that would introduce major loopholes, and similarly stringent rules should be finalized for hydrogen production involving biomethane and fossil fuels.

Numerous studies have now made clear that 45V tax credits would have devastating consequences for our climate and communities if Treasury rules do not require hydrogen producers to fully account for their emissions. GHG emissions would spike as tax credits reserved for "clean hydrogen" illegally subsidize hydrogen production with carbon intensities that in fact exceed the statutory thresholds while causing fossil fuel power plants to ramp up operations;[2] agricultural industries to make more biomethane or sell bogus biomethane credits to fossil fuel users who seek to ignore their emissions;[3] and oil and gas basins to increase production, inducing more pollution on the way from well-to-gate.[4] Power prices would also rise as energy-hungry hydrogen producers increase electricity demand without regard for supply, burdening families with higher utility bills.[5] Meanwhile, tax credits intended to spur development of a truly clean hydrogen economy and help the United States cut climate-warming

[1] 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. 89,220 (Dec. 26, 2023) ("Proposed Rule"), https://www.govinfo.gov/content/pkg/FR-2023-12-26/pdf/2023-28359.pdf.

[2] W. Ricks et al., Minimizing Emissions from grid-based hydrogen production in the United States, 18 Env't Rsch. Letters 1 (2023) ("Princeton Three Pillars Study"), https://iopscience.iop.org/article/10.1088/1748-9326/acacb5 (attached); Energy Innovation, Smart Design Of 45V Hydrogen Production Tax Credit Will Reduce Emissions And Grow the Industry (Apr. 11, 2023) ("Energy Innovation, Smart Design of 45V"), https://energyinnovation.org/publication/smart-design-of-45v-hydrogen-production-tax-credit-will-reduce-emissions-and-grow-the-industry/; B. Haley & J. Hargreaves, 45V Hydrogen Production Tax Credits: Three-Pillars Accounting Impact Analysis, Evolved Energy Rsch. (June 23, 2023) ("Evolved Energy Report"), https://www.evolved.energy/post/45v-three-pillars-impact-analysis (attached); EPRI & GTI Energy, Impacts of IRA's 45V Clean Hydrogen Production Tax Credit (Nov. 3, 2023) ("EPRI 45V Paper"), https://www.epri.com/research/products/000000003002028407.

[3] Jeff St. John, The biomethane boondoggle that could derail clean hydrogen, Canary Media (Sept. 11, 2023), https://www.canarymedia.com/articles/hydrogen/the-biomethane-boondoggle-that-could-derail-clean-hydrogen.

[4] *See, e.g.*, R. W. Howarth & M. Z. Jacobson, How green is blue hydrogen?, 9 Energy Sci. & Eng'g 1676 (2021) ("Howarth & Jacobson"), https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.956 (attached).

[5] *See, e.g.*, Energy Innovation, Consumer Cost Impacts of 45V Rules (Nov. 2023) ("Energy Innovation, Consumer Cost Impacts of 45V Rule"), https://energyinnovation.org/wp-content/uploads/2023/11/Consumer-Cost-Impacts-of-45V-Rules-1.pdf (attached).

emissions would do the opposite—pouring billions of dollars into hydrogen with carbon intensities similar to or higher than the dirtiest, status quo hydrogen of today.[6]

Treasury's Proposed Rule reflects these high stakes by establishing robust carbon-accounting practices for electrolytic hydrogen production that are necessary for the agency to fulfill Congress's mandate to only award 45V tax credits to projects that meet the statutory emissions thresholds. The agency's adoption of stringent criteria—incrementality, hourly matching, and deliverability, often called the "three pillars"—correctly accounts for the induced grid emissions from electrolytic hydrogen production, which plays a significant role in the Biden Administration's roadmap for the hydrogen industry.[7] Strict adherence to the three pillars is necessary to avoid the disastrous climate- and community-level consequences of subsidizing dirty hydrogen noted above.

Treasury will need to be just as rigorous in its carbon accounting for hydrogen produced from methane. Hydrogen producers that procure and take delivery of fossil methane must not have the opportunity to ignore the direct emissions from their methane use by purchasing paper credits from biomethane producers. For hydrogen producers that use biomethane or fugitive methane, Treasury should only treat these feedstocks as lower-emitting than fossil fuels when they come from an unavoidable waste stream that has not been put to prior productive use. Any other approach would provide a powerful incentive to create additional methane waste through unsustainable practices that also burden neighboring communities with health-harming pollution. Finally, Treasury should accurately account for the emissions intensity of fossil hydrogen through commonsense measures, such as updating 45VH2-GREET's assumptions on methane leakage to reflect real-world data. Proper carbon accounting will ensure Treasury does not illegally grant tax credits to hydrogen producers that fail to meet 45V's emission thresholds.

Earthjustice and Sierra Club appreciate the opportunity to submit these comments on Treasury's Proposed Rule and urge the agency to finalize the rule without adding exemptions to the criteria for electrolytic hydrogen, and with changes to incorporate robust measures to properly account for the emissions from methane-derived hydrogen and hydrogen leakage, discussed in detail below.

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[6] *See* The White House, Treasury Sets Out Proposed Rules for Transformative Clean Hydrogen Incentives (Dec. 22, 2023), https://whitehouse.gov/cleanenergy/clean-energy-updates/2023/12/22/treasury-sets-out-proposed-rules-for-transformative-clean-hydrogen-incentives/ (describing 45V as "what stands to be the most consequential policy supporting the deployment of clean hydrogen in U.S. history" and "part of the administration's broader efforts to support hydrogen and other technologies that will enable the U.S. to cut emissions from so-called hardest-to-abate sectors of the economy, including heavy industry and long-haul transportation").

[7] *See, e.g.*, U.S. National Clean Hydrogen Strategy and Roadmap (June 2023), https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.

II. TREASURY'S FINAL RULE SHOULD REQUIRE STRICT ADHERENCE TO THE "THREE PILLARS" TO SUBSTANTIATE ANY CLAIM THAT AN ELECTROLYTIC HYDROGEN PRODUCER USES ZERO-CARBON ELECTRICITY.

A. The Three Pillars Are Necessary for Treasury to Fulfill Its Statutory Duty to Include Significant Indirect Emissions in Its Determination of Electrolytic Hydrogen's Lifecycle Greenhouse Gas Emissions.

Treasury cannot grant Clean Hydrogen Production Tax credits to producers whose emissions exceed the statutory thresholds in Section 45V. Treasury has correctly determined that electrolytic hydrogen producers should be required to comply with the three pillars because, otherwise, there is a "significant risk" that hydrogen production will exceed the statutory emissions thresholds.[8] Thus, the three pillars are necessary for the agency to carry out its statutory duty.

Section 45V awards tax credits based on the "lifecycle greenhouse gas emissions rate" of hydrogen projects.[9] The statute defines "lifecycle greenhouse gas emissions" of hydrogen projects by referencing Section 211(o)(1)(H) of the Clean Air Act ("CAA"), which in turn defines those emissions to include both "direct emissions and significant indirect emissions" linked to the production of a fuel.[10]

"Significant indirect emissions" of electrolytic hydrogen production include induced grid emissions and, therefore, such grid emissions must be accounted for in the lifecycle GHG emissions rate of electrolytic hydrogen. The plain language of CAA Section 211(o)(1)(H)—which 45V incorporates—requires this result. Section 211(o)(1)(H) provides that "lifecycle greenhouse gas emissions" include "significant indirect emissions **such as** significant emissions from land use changes."[11] The text makes clear that significant emissions from land use changes are an example of the types of indirect emissions that must be accounted for in the lifecycle GHG emissions rate of fuel production.

Induced grid emissions from electrolytic hydrogen production result from a similar mechanism as the indirect land use change emissions from biofuel production. As the U.S. Environmental Protection Agency ("EPA") observed, the overall demand for a crop is one of the

[8] 88 Fed. Reg. at 89,229.
[9] 26 U.S.C. § 45V(b)(2).
[10] *Id.* § 45V(c)(1)(A); 42 U.S.C. § 7545(o)(1)(H) ("The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.").
[11] 42 U.S.C. § 7545(o)(1)(H) (emphasis added).

main factors that drives the conversion of land into crop production.[12] Similarly, overall electric demand on a regional grid is a prime driver of grid emissions because grid operators dispatch generators until they serve total demand, often dispatching the dirtiest generators last. In both cases, increasing demand for a fungible product increases overall emissions, even when a market participant procures a unit of that product with relatively low direct emissions. Thus, induced grid emissions are indirect emissions from electrolytic hydrogen production, just as emissions from land use changes are indirect emissions from biofuel production.

Induced grid emissions from electrolytic hydrogen production are also significant. As Treasury correctly states in its Proposed Rule, "there is a significant risk that hydrogen production would significantly increase induced grid GHG emissions beyond the allowable levels required to qualify for the section 45V credit" without the three pillars.[13] EPA likewise observes in its letter to Treasury on 45V: "electrolysis projects that use large amounts of grid electricity to produce hydrogen have the potential to be several times more greenhouse-gas intensive than the threshold for even the lowest value IRC section 45V tax credit tier, and could in fact be more greenhouse-gas intensive than existing forms of conventional hydrogen production."[14] Multiple studies support this conclusion and consistently find that electrolytic hydrogen production could increase grid emissions by hundreds of millions of metric tons.[15]

Accounting for induced grid emissions in the lifecycle GHG emissions rate of electrolytic hydrogen production is consistent with EPA's longstanding interpretation of the term "significant indirect emissions" in CAA Section 211(o)(1)(H), which Congress knew about when

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[12] EPA, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, EPA-420-R-10-006, at 316 (Feb. 2010) ("RFS2 RIA"), https://nepis.epa.gov/Exe/ZyNET.exe/P1006DXP.TXT?ZyActionD=ZyDocument&Client=EPA&Index=2006+Thru+2010&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C06thru10%5CTxt%5C00000015%5CP1006DXP.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL.

[13] 88 Fed. Reg. at 89,229.

[14] J. McCabe, EPA, Letter to Assistant Secretary L. Batchelder, Department of Treasury, 5 (Dec. 20, 2023) ("EPA 45V Letter"), https://home.treasury.gov/system/files/136/45V-NPRM-EPA-letter.pdf.

[15] *See, e.g.*, Evolved Energy Report at PDF pp. 29–30 (finding that the three pillars cumulatively avoid 192–416 million metric tons of carbon emissions through 2030 and 247–643 million metric tons of carbon emissions through 2032); Rhodium Grp., Scaling Green Hydrogen in a post-IRA World (Mar. 16, 2023) ("Rhodium Grp., Scaling Green Hydrogen"), https://rhg.com/research/scaling-clean-hydrogen-ira/ (finding that annual GHG emissions could increase by 73 million metric tons in 2030 without the incrementality pillar, and by 34–58 million metric tons if annual matching were allowed instead of hourly matching) (attached); Env't Res. Mgmt. ("ERM"), Assessment of Grid Connected Hydrogen Production Impacts, at 9 (Feb. 2024) ("ERM Report"), https://www.erm.com/globalassets/documents/publications/assessment-of-grid/assessment-of-grid-connected-h2-electrolysis-impact_part-i_lit-review_final.pdf (providing a literature review of approximately 30 reports on electrolytic hydrogen production and concluding "the consensus in the analysis is clear that GHG emissions will increase considerably without incrementality requirements") (attached); EPRI 45V Paper at 4 (finding that without the three pillars, 45V could increase carbon emissions by approximately 340 million metric tons in 2035).

it enacted 45V.[16] In its letter supporting Treasury's proposed adoption of the three pillars, EPA explains that it interpreted "significant indirect emissions" in its 2010 renewable fuel standards rulemaking to require an accounting of "the real-world emissions consequences of increased production of renewable fuels."[17] In that rulemaking, EPA concludes:

> The definition of lifecycle greenhouse gas emissions established by Congress . . . and specifically the clause "(including direct emissions and significant indirect emissions such as significant emissions from land use changes)" **requires the Agency to consider [] consequential lifecycle analyses and to develop a methodology that accounts for all of the important factors that may significantly influence this assessment**, including the secondary or indirect impacts of expanded biofuels use.[18]

EPA adds: a "consequential approach to GHG emissions accounting in products provides information about the GHG emitted, directly or indirectly, as a consequence of changes in demand for the product" and "typically describes changes in GHG emissions levels from affected processes, which are identified by linking causes with effects."[19] Based on this long-standing interpretation, EPA concludes in its 45V letter that it would be consistent with EPA precedent "for Treasury to determine that induced grid emissions are an anticipated real-world result of electrolytic hydrogen production that must be considered in lifecycle greenhouse-gas analyses under IRC section 45V."[20] It would be improper for Treasury to disregard EPA's consistent and longstanding interpretation of the definition of "lifecycle greenhouse gas emissions," when Congress explicitly delegated to EPA responsibility for determining a fuel's aggregate GHG emissions.[21]

Just as Congress's definition of "lifecycle greenhouse gas emissions" requires EPA to account for significant consequential GHG emissions from renewable fuel production—such as emissions from land use changes—that same definition incorporated in 45V requires Treasury to account for significant consequential GHG emissions from hydrogen production—such as induced grid emissions. Thus, pursuant to the statutory language of 45V, Treasury must account for induced grid emissions when determining whether electrolytic hydrogen production meets the statutory lifecycle greenhouse gas emissions threshold to be eligible for 45V tax credits. Any alternative interpretation would be legally unsupported.

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[16] *See Lamar, Archer & Cofrin, L.L.P. v. Appling*, 584 U.S. 709, 722 (2018) (quoting *Lorillard v. Pons*, 434 U.S. 575, 580 (1978)) ("Congress is presumed to be aware of an administrative or judicial interpretation of a statute and to adopt that interpretation when it re-enacts a statute without change."); *Bragdon v. Abbott*, 524 U.S. 624, 645 (1998) ("When administrative and judicial interpretations have settled the meaning of an existing statutory provision, repetition of the same language in a new statute indicates, as a general matter, the intent to incorporate its administrative and judicial interpretations as well.").

[17] EPA 45V Letter at 3.

[18] EPA, RFS2 RIA at 299 (cited in EPA 45V Letter at 3, n. 8) (emphasis added) (original emphasis omitted).

[19] *Id.* (original emphasis omitted).

[20] EPA 45V Letter at 2.

[21] 42 U.S.C. § 7545(o)(1)(H) ("The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), **as determined by the Administrator**…") (emphasis added).

In effectuating this statutory duty, Treasury rightly determines that the three pillars are the correct method to account for induced grid emissions. Without adherence to the three pillars, electrolytic hydrogen producers cannot feasibly demonstrate that their electricity use is likely to have zero "significant indirect emissions."[22] This is consistent with EPA's observation that Energy Attribute Certificates ("EACs") that comply with the three pillars are "an appropriate way of verifying the generation and delivery of zero greenhouse-gas-emitting electricity."[23] Thus, requiring electrolytic hydrogen producers to strictly adhere to the three pillars allows Treasury to fulfill its statutory duty to ensure that significant indirect emissions are accounted for in determining eligibility for 45V tax credits.

B. Weakening the Three Pillars Would Have Serious Consequences for the Climate and Communities.

Treasury's Proposed Rule correctly accounts for the induced grid emissions of electrolytic hydrogen production by adopting the three pillars. Any weakening of the pillars would result in inaccurate and unlawful accounting of these induced emissions impacts and would have serious consequences for the climate and communities.

Treasury rightly concludes in its Proposed Rule that without the three pillars, "there is a significant risk that hydrogen production would significantly increase induced grid GHG emissions beyond the allowable levels required to qualify for the section 45V credit."[24] Ample evidence supports this conclusion.

For example, researchers at Princeton modeled emissions from grid-based electrolytic hydrogen production in southern California with and without the three pillars. They found that removing any one of the three pillars dramatically increased the carbon intensity of electrolytic hydrogen production. Without incrementality (referred to as additionality in the study), the carbon intensity of electrolytic hydrogen production equaled 20 kilograms carbon dioxide equivalent per kilogram of hydrogen (kg CO_2e/kg H_2)—twice that of grey hydrogen—even if hourly matching was required.[25] Likewise, without hourly matching, the emissions intensity of electrolytic hydrogen exceeded even the minimum emissions threshold in 45V—often reaching double the intensity of grey hydrogen, and in one instance, reaching nearly four times the intensity of grey hydrogen.[26] They also found that requiring weekly or annual matching instead of hourly matching is "universally ineffective at reducing consequential emissions from grid-based hydrogen production."[27] Finally, without deliverability, they found that zero-carbon resources "cannot be relied on to eliminate emissions from hydrogen production" due to transmission constraints.[28] In another study, researchers used an example of an electrolyzer

[22] See independent research cited in footnote 2.
[23] EPA 45V Letter at 6 (also stating that "it would be reasonable to expect that the purchase and use of zero-emitting electricity represented by three-pillar EACs does not result in induced grid emissions").
[24] 88 Fed. Reg. at 89,229.
[25] Princeton Three Pillars Study at PDF pp. 11, 35 (Supplementary Figure 19).
[26] *Id.* at PDF pp. 7–10.
[27] *Id.* at PDF p. 9.
[28] *Id.* at PDF p. 11.

located in Colorado but hourly matched with power from a new, zero-carbon resource in Texas to estimate the emissions impact of no deliverability requirements. They found that such a project would produce hydrogen with a GHG emissions intensity of over 12 kg CO_2/kg H_2, which is higher than grey hydrogen.[29] Numerous studies have reached similar conclusions about the emissions impact of the three pillars.[30]

Thus, without strict adherence to each of the three pillars, climate-warming emissions will surge.[31] According to one report from Evolved Energy Research, requiring compliance with the three pillars cumulatively avoids approximately 200–400 million metric tons of carbon emissions through 2030 and 250–650 million metric tons of carbon emissions through 2032.[32] This makes it imperative for Treasury to reject potential exemptions to the incrementality requirement that would create substantial loopholes for highly carbon-intensive hydrogen production to access 45V credits. A recent study from Rhodium Group demonstrates the massive emissions impact that these potential exemptions could have, finding that they could increase emissions by between 23 million metric tons to 1.5 billion metric tons cumulatively through 2035, depending on the exemption.[33] These potential exemptions, and why Treasury should reject them, are discussed in detail below.

Weakening the three pillars would have detrimental consequences beyond climate impacts. It would significantly raise power prices[34] and increase the use of fossil-fueled power

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[29] Energy Innovation, Smart Design of 45V at 23.

[30] *See e.g.*, *id.* at 19 (finding that "forgoing additionality can increase GHG emissions from hydrogen electrolysis as much as 5 times compared to SMR [("Steam Methane Reformation")] and upwards of 100 times above the 45V threshold for the top tax credit value"). *See also* Evolved Energy Report; EPRI 45V Paper.

[31] Removing the incrementality pillar alone could cause an increase in annual carbon emissions of 73 million metric tons ("MMT") in 2030, when our power grid will presumably be cleaner than today's grid. Rhodium Grp., Scaling Green Hydrogen. Likewise, allowing annual matching instead of hourly matching "could increase total greenhouse gas emissions from hydrogen production by 34–58 MMT in 2030 above today's 100 MMT per year level—a roughly 1% increase in economy-wide GHG emissions—and a cumulative 56–97 MMT increase in emissions from 2023 through 2030." *Id.* Energy Innovation has emphasized the importance of evaluating the interrelationship between each of the three pillars and the resulting emissions impact of removing the incrementality pillar, calling that pillar "the bedrock upon which the other two principles lie—without additionality, time-matching and deliverability don't avoid emissions as intended." Energy Innovation, Smart Design of 45V at 18. *See also* ERM Report at 17 (stating that the studies reviewed in its report "find significant interdependency between temporality and incrementality on emissions impact" and "underscore[]the importance of evaluating the pillars holistically, and the unique significance of the incrementality pillar"); EPRI 45V Paper at 4.

[32] Evolved Energy Report at PDF pp. 29–30.

[33] B. King et al., How Clean Will US Hydrogen Get? Unpacking Treasury's Proposed 45V Tax Credit Guidance, Rhodium Grp. (Jan. 4, 2024) ("Rhodium Grp., How Clean Will US Hydrogen Get?"), https://rhg.com/research/clean-hydrogen-45v-tax-guidance/ (finding that, from 2024–2035, an avoided retirements exemption for existing hydropower facilities could result in a 23–165 MMT net increase in emissions; the same exemption for existing nuclear reactors could result in a 33–360 MMT net increase; and a 5% exemption for existing generators could result in a 1.5 billion metric ton net increase) (attached).

[34] Energy Innovation, Consumer Cost Impacts of 45V Rule at 1 ("It's reasonable to expect double digit percentage increases in electricity prices without an additionality requirement for electrolyzers."), 3 (explaining that consumer power prices would also increase without hourly matching or deliverability) (original emphasis omitted); *see also* Princeton Three Pillars Study, Research Addendum: Consumer Electricity Price Impacts of the 45V Hydrogen Production Tax Credit (Oct. 25, 2023), https://zenodo.org/records/10041735 (finding that without the three pillars, average wholesale electricity prices would be 8% higher in southern California, and 10% higher in Wyoming and Colorado) (attached).

plants, which have been dumping health-harming pollution onto neighboring communities for decades. Of particular concern is the ramping up of fossil-fueled peaker plants. Those plants are often the marginal units on today's power grid, and would be the plants called upon to fill the power gap created by electrolyzers that siphon zero-carbon energy from other users. These peaker plants are predominantly located near lower-income communities, and their emissions disproportionately burden people of color.[35] In the long term, the additional load from hydrogen production could extend the lives of antiquated fossil-fueled generators unless hydrogen producers rely on clean energy, consistent with the three pillars.

Weakening the three pillars and providing unearned subsidies for hydrogen production that increases health-harming pollution would contravene the Biden Administration's commitments to environmental justice communities. Under President Biden's all-of-government approach to environmental justice, each agency is responsible for adopting "measures to avoid, minimize or mitigate disproportionate and adverse human health and environmental effects (including risks) and hazards of Federal activities on communities with environmental justice concerns, to the maximum extent practicable."[36] Without the three pillars, frontline communities already facing substantial cumulative burdens from decades of unjust siting practices will be forced to deal with yet more toxic pollution from neighboring fossil fuel power plants serving electolyzers' loads. Moreover, electricity rates would rise if hydrogen producers are not responsible for ensuring electricity supplies keep pace with their significant new demand, imposing a disproportionate economic burden on low-income households.

In sum, Treasury's final rule should require electrolytic hydrogen projects to strictly adhere to the three pillars. Treasury correctly determines that without the three pillars, there is a "significant risk" that electrolytic hydrogen production would exceed the statutory emissions thresholds, which are based on a full accounting of lifecycle GHG emissions that includes induced grid emissions. The three pillars are also necessary to protect against spikes in health-harming pollution that would be inimical to President Biden's environmental justice commitments. The Proposed Rule's incorporation of the three pillars for electrolytic hydrogen is a legally required and administratively sound approach to carrying out the duties Congress set forth in 45V. Treasury should not backslide by allowing exemptions to the three pillars in its final rule.

C. Treasury's Proposed Rule Correctly Takes a Strict Approach to Incrementality That Should Not Be Weakened in the Final Rule.

Treasury's Proposed Rule requires an electrolytic hydrogen producer to satisfy the incrementality requirement by purchasing EACs from an electricity generation facility that either (1) has a commercial operations date that is no more than 36 months before the hydrogen

[35] S. Mullendore, Peaker Power Plant Data Show Persistent Economic and Racial Inequities, Clean Energy Grp. (Sept. 7, 2023), https://www.cleanegroup.org/peaker-power-plant-data-show-persistent-economic-and-racial-inequities/.

[36] The White House, Executive Order on Revitalizing Our Nation's Commitment to Environmental Justice for All, Section 3(vi) (Apr. 21, 2023), https://www.whitehouse.gov/briefing-room/presidential-actions/2023/04/21/executive-order-on-revitalizing-our-nations-commitment-to-environmental-justice-for-all/.

production facility was placed into service; or (2) had an uprate no more than 36 months before the hydrogen production facility was placed into service and the electricity represented by the EAC is from the facility's uprated production.[37] This requirement is a reasonable and necessary way to ensure compliance with the incrementality pillar, consistent with EPA's conclusion that "EACs with attributes that meet the criteria of new incremental capacity, geographic matching and temporal matching are an appropriate way of verifying the generation and delivery of zero greenhouse-gas-emitting electricity and can serve as a reasonable methodological proxy for quantifying induced grid emissions associated with electrolytic hydrogen product."[38] Treasury's final rule should strictly adhere to this requirement, and should not allow exemptions.

1. Treasury should not create an "avoided retirements" exemption.

Treasury should not create an "avoided retirements" exemption to the incrementality requirement because it risks increasing GHG emissions and providing tax credits to producers who do not in fact meet 45V's emissions thresholds. In practice, an exemption for avoided retirements threatens to become a massive loophole that directly undermines the goal of 45V. Moreover, the lucrative subsidies already available to nuclear reactors cast doubt on any claims that reactors would retire but for access to 45V credits. If Treasury nevertheless decides to allow an avoided retirements exemption—and it should not—then the agency should at a minimum require a rigorous, case-by-case analysis of plant finances before awarding credits to limit abuse of the exemption. Treasury could require a similar analysis to the one the U.S. Department of Energy ("DOE") must perform before certifying nuclear reactors for the Civil Nuclear Credit Program (discussed below).

a. The avoided retirements exemption could spike climate emissions.

Creating an avoided retirements exemption could have a significant impact on climate emissions because our existing nuclear reactors are among the largest providers of carbon-free power. A Rhodium Group analysis on the Proposed Rule concludes that the "emissions impacts of allowing existing zero-emitting generation to qualify [for 45V credits] could be huge."[39] Their analysis finds that "net cumulative emissions from shifting all existing nuclear generation to producing hydrogen would increase by **1.3-4.7 billion metric tons** [CO_2e] from 2024-2035," underscoring the "importance of getting the rules right."[40] Regarding the proposed avoided retirement exemption specifically, Rhodium Group estimates a net emissions increase of **33-360 million metric tons** [CO_2e] if every nuclear reactor whose license expires before 2036 (~28 Gigawatts ("GW"), or 30% of the fleet) relicenses to serve hydrogen production instead of the load on the grid.[41]

[37] 88 Fed. Reg. at 89,249.
[38] EPA 45V Letter at 6.
[39] Rhodium Grp., How Clean Will US Hydrogen Get?
[40] *Id.* (emphasis added).
[41] *Id.* (emphasis added).

While in theory the exemption may "not result[] in induced grid emissions compared to a scenario in which the plant retires,"[42] in practice the exemption could cause substantial emissions consistent with Rhodium Group projections because it would create significant opportunities for gamesmanship. Retirement decisions are complex and based on multiple variables. Yet, an avoided retirements exemption risks providing cover for nuclear companies to claim their retirement decisions are reduced to a single variable—access to 45V credits—and to divert their zero-carbon power from the grid to hydrogen production if they determine it would be more profitable for them to do so. Treasury must avoid this result.

b. Treasury should scrutinize any claims of avoided retirements in light of recent federal subsidies for the nation's nuclear fleet.

Recently created federal subsidies for nuclear generation raise doubts about any claim that nuclear reactors would retire but for access to 45V. Along with the 45V tax credits, the Inflation Reduction Act ("IRA") created the 45U "zero-emission nuclear power production credit"[43] for existing nuclear plants, which is available from December 31, 2023 through December 31, 2032.[44] The 45U credit is tied to power prices and gradually decreases as power prices rise. The credit amounts to 0.3 cents per kilowatt-hour ("kWh") of electricity produced and sold by a nuclear plant each year (indexed for inflation and increasing fivefold if certain prevailing wage requirements are met) and declines gradually as power prices rise above a certain threshold.[45] That threshold (aka "reduction amount") equals 16% of the excess of the average gross receipts from any electricity produced and sold by the nuclear plant over the product of 2.5 cents and the number of kWh of electricity produced and sold by that nuclear plant over a given taxable year.[46] "Gross receipts" includes state subsidies, like those in Illinois discussed below.[47] Applying the statutory formula, the 45U tax credit is available as long as a nuclear plant's average gross receipts are under 4.375 cents per kWh, or $43.75 per megawatt hour ("MWh").[48]

In addition to the IRA's 45U tax credit, the Bipartisan Infrastructure Law ("BIL") created the $6 billion Civil Nuclear Credit program for existing nuclear reactors.[49] A reactor is eligible for the credit if DOE "determines that the nuclear reactor is projected to cease operations due to economic factors" (among other determinations) based on information about the reactor's

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[42] 88 Fed. Reg. at 89,230.
[43] 26 U.S.C. § 45U.
[44] *Id.* § 45U(e).
[45] *Id.* §§ 45U(a), (b)(2), (d)(1).
[46] *Id.* § 45U(b)(2).
[47] *Id.* § 45U(b)(2)(B).
[48] Translating the statutory text to a formula:
45U tax credit per kWh = 5 x [0.3 cents – 0.16 (average gross receipts – 2.5 cents)]
= 1.5 cents – 0.8 (avg. gross receipts – 2.5 cents)
= 1.5 cents + [(-0.8 x avg. gross receipts) + (-0.8 x -2.5 cents)]
= 1.5 cents – (0.8 x avg. gross receipts) + 2 cents
= [3.5 cents – (0.8 x avg. gross receipts)] cents
= [0.8 x (4.375 – avg. gross receipts)] cents.
[49] *See generally* 42 U.S.C. § 18753.

operating costs.[50] DOE has certified only one application from the program's first award cycle (from Pacific Gas and Electric Company for its Diablo Canyon Power Plant); DOE certified no applications during the program's second and most recent award cycle.[51]

The availability of these federal subsidies for struggling nuclear reactors, combined with the fact that DOE has so far certified only one reactor for the Civil Nuclear Credit program, demonstrates that Treasury would need to closely scrutinize any claim that reactors face retirement before they are permitted to access yet more federal subsidies under 45V.

c. A close look at Illinois' 11 nuclear reactors raises further doubts about claims that reactors would retire without access to 45V.

Illinois has more operating nuclear reactors than any other state in the United States.[52] Of the 93 reactors operating at 54 power plants across 28 states, 11 are located at six plants in Illinois:[53] the Braidwood, Byron, Clinton, Dresden, LaSalle, and Quad Cities power stations.[54] The total nameplate capacity of these Illinois nuclear reactors (11,582 megawatts ("MW")) is 12% of total U.S. operating nuclear electricity generation capacity.[55] Constellation Energy Corporation owns and operates all six of the Illinois nuclear plants.[56]

Of Illinois' 11 nuclear reactors, nine are or could soon be licensed to operate into the 2040s. Six of them already are: Braidwood's Unit 1 is licensed through 2046 and Unit 2 through 2047;[57] Byron's Unit 1 through 2044 and Unit 2 through 2046;[58] and LaSalle's Unit 1 through 2042 and Unit 2 through 2043.[59] Just 11 days before the deadline for these comments, Constellation announced that it had filed a 20-year license renewal application for its single reactor at Clinton, which is currently licensed through 2027.[60] If that application is approved, Clinton Unit 1 will be licensed through 2047.[61] Constellation has also announced plans to seek

[50] 43 U.S.C. § 18753(c)(1)(A)(i).
[51] DOE, Civil Nuclear Credit Program, https://www.energy.gov/gdo/civil-nuclear-credit-program; B. Dabbs, No takers for Biden's nuclear bailout, E&E News (Jan. 8, 2024), https://subscriber.politicopro.com/article/eenews/2024/01/08/no-takers-for-bidens-nuclear-bailout-00134067.
[52] U.S. Energy Information Administration ("EIA"), Nuclear Explained, U.S. Nuclear Industry, https://www.eia.gov/energyexplained/nuclear/us-nuclear-industry.php (last updated Aug. 24, 2023).
[53] *Id.*
[54] *See, e.g.*, Ready Illinois, Nuclear Power Plants, https://ready.illinois.gov/hazards/nuclearpowerplants.html.
[55] EIA, Frequently Asked Questions (FAQs): How many nuclear power plants are in the United States, and where are they located?, https://www.eia.gov/tools/faqs/faq.php?id=207&t=21/ (last updated Aug. 3, 2023).
[56] Constellation, Our Locations: Strengthening the Communities We Serve, https://www.constellationenergy.com/our-company/locations/location-sites.html. According to fact sheets for each plant on Constellation's website, Constellation has a 100% ownership interest in each plant but the Quad Cities station, for which Constellation has a 75% ownership interest and MidAmerican Energy Company has a 25% ownership interest.
[57] Constellation, License Renewals: Supporting Carbon Free Energy Into the Future, https://www.constellationenergy.com/our-company/locations/license-renewals.html.
[58] *Id.*
[59] *Id.*
[60] Constellation, Constellation Seeks License Renewal of Clinton Clean Energy Center for Additional 20 Years (Feb. 15, 2024), https://www.constellationenergy.com/newsroom/2024/Constellation-Seeks-License-Renewal-of-Clinton-Clean-Energy-Center-for-Additional-20-Years.html.
[61] *Id.*

20-year renewals for both of its Dresden reactors this year (Unit 2 is currently licensed through 2029 and Unit 3 is currently licensed through 2031).[62] This would mean all but the two Quad Cities reactors (currently licensed through 2032)[63] would be licensed to operate past 2042. Constellation has until December 2029 to decide whether to seek relicensing of its Quad Cities reactors.[64]

The 45V tax credit is available for a ten-year period for qualifying hydrogen production facilities that begin construction before January 1, 2033.[65] Assuming electrolytic hydrogen projects take approximately 12 months from construction to operation—which is consistent with current project timelines[66]—then an electrolytic hydrogen facility that begins construction on January 1, 2033 would start producing hydrogen and become eligible for the 45V tax credit roughly by December 31, 2033 and cease receiving the credit by December 31, 2043.[67] Actual project timelines could be longer or shorter, but as lucrative federal subsidies for electrolytic hydrogen work their way into the market and electrolyzer manufacturing scales up, it is reasonable to assume that most 45V tax credits will be administered before 2043.[68]

As noted above, six of Constellation's 11 Illinois nuclear reactors are already licensed to operate into the 2040s. Constellation sought relicensing for each of these six reactors long before the 45V tax credit was created through the IRA's passage in 2022,[69] meaning 45V did not play a role in those relicensing decisions. **This includes Unit 2 at LaSalle, licensed through 2043, which Constellation intends to use to produce hydrogen as part of the "Midwest Alliance for Clean Hydrogen" Hub ("MachH2") (Unit 1's license expires just one year shy of 2043).**[70] Reactors at two more of Constellation's nuclear plants soon could be licensed through

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[62] *Id.*; *see also* Constellation, Dresden Generating Station: Nuclear: An Ideal Foundation for Our Clean Energy Future, https://www.constellationenergy.com/our-company/locations/location-sites/dresden-generating-station.html.
[63] Constellation, License Renewals: Supporting Carbon Free Energy Into the Future, https://www.constellationenergy.com/our-company/locations/license-renewals.html.
[64] 88 Fed. Reg. 32,253, 32,254 (May 19, 2023) ("Constellation Quad Cities Exemption"), https://www.federalregister.gov/documents/2023/05/19/2023-10723/constellation-energy-generation-llc-quad-cities-nuclear-power-station-units-1-and-2.
[65] 26 U.S.C. §§ 45V.
[66] *See, e.g.*, Duke Energy, DeBary Hydrogen Energy System, https://www.duke-energy.com/our-company/environment/renewable-energy/solar-energy/debary (estimating that construction of a solar-powered electrolysis facility will begin in "late 2023" with project completion in "late 2024").
[67] Likewise, modelers have predicted that Section 45V will only incentivize hydrogen production through 2044. *See, e.g.,* EPRI 45V Paper at 15, Figure 3.
[68] *Id.* The Rhodium Group projects that between 2 GW to 23.4 GW of electrolyzer capacity will be online as early as 2027. Rhodium Grp., How Clean Will US Hydrogen Get?
[69] Byron's 2 reactors were relicensed in 2015 (Constellation, Byron Clean Energy Center—Nuclear: An Ideal Foundation for Our Clean Energy Future, https://www.constellationenergy.com/our-company/locations/location-sites/byron-generating-station.html); Braidwood's 2 reactors were relicensed in 2016 (Constellation, Braidwood Clean Energy Center—Nuclear: An Ideal Foundation for Our Clean Energy Future, https://www.constellationenergy.com/our-company/locations/location-sites/braidwood-generating-station.html); and LaSalle's 2 reactors were relicensed in 2016 (Constellation, LaSalle Clean Energy Center—Nuclear: An Ideal Foundation for Our Clean Energy Future, https://www.constellationenergy.com/our-company/locations/location-sites/lasalle-county-generating-station.html).
[70] Constellation, Constellation To Play Key Role in $1 Billion Clean Hydrogen Hub Awarded by U.S. Department of Energy (Oct. 16, 2023), https://www.constellationenergy.com/newsroom/2023/Constellation-To-Play-Key-Role-in-1-Billion-Clean-Hydrogen-Hub-Awarded-by-US-Department-of-Energy.html.

2043 too. "The decision to seek license renewal rests entirely with nuclear power plant owners" and **"[t]his choice is typically based on the plant's economic situation** and whether it can meet NRC [Nuclear Regulatory Commission] requirements."[71]

Constellation's relicensing decisions are not surprising given the generous state subsidies available to the company on top of the hefty federal subsidies discussed above.[72] In Illinois, two laws created significant subsidies for the state's nuclear reactors through May 31, 2027: the 2016 Future Energy Jobs Act ("FEJA") (Public Act 99-0906) and the 2021 Climate and Equitable Jobs Act ("CEJA") (Public Act 102-0062). FEJA directs hundreds of millions of dollars in subsidies per year for ten years to Constellation's nuclear reactors in response to threatened retirements.[73,74] The law accomplishes this by creating a zero emission credit ("ZEC") program and requiring Illinois electric utilities to enter ten-year contracts to purchase ZECs from Illinois nuclear reactors equal to 16% of the amount of electricity those utilities provide to their retail customers.[75] These contracts expire May 31, 2027.[76] The selected bidders in the ZEC program

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[71] U.S. Nuclear Regul. Comm'n, Backgrounder on Reactor License Renewal, https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/fs-reactor-license-renewal.html#process (emphasis added).

[72] The state subsidies available to nuclear reactors in Illinois are illustrative of how state-specific policies can significantly impact the financial health of the nation's nuclear fleet; Illinois is not alone in heavily subsidizing its nuclear reactors. *See generally*, Congressional Rsch. Serv., U.S. Nuclear Plant Shutdowns, State Interventions, and Policy Concerns (June 10, 2021) ("CRS Report"), https://crsreports.congress.gov/product/pdf/R/R46820/3 (describing state-specific interventions in Connecticut, Illinois, New Jersey, New York, Ohio, and Pennsylvania that provide financial support for a total of 16 nuclear reactors (representing 15,734 MW of electricity generation capacity or 16.5% of total current U.S. nuclear capacity) "that had been previously announced for closure or identified as likely to close") (attached); EIA, Five states have implemented programs to assist nuclear power plants (Oct. 7, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41534.

[73] *See, e.g.*, CRS Report at 10-11; P. Maloney, Why Exelon's mammoth Illinois energy bill could set a precedent for other states, Utility Dive (Dec. 12, 2016), https://www.utilitydive.com/news/why-exelons-mammoth-illinois-energy-bill-could-set-a-precedent-for-other-s/432089/.

[74] Constellation was a subsidiary of Exelon when FEJA and CEJA passed, but spun off from Exelon in 2022. *See, e.g.*, Exelon, Exelon Completes Separation of Constellation, Moving Forward as Nation's Premier Transmission and Distribution Utility Company (Feb. 2, 2022), https://www.exeloncorp.com/newsroom/exelon-completes-separation-of-constellation. For more on the circumstances that led to FEJA's passage, including disagreements about whether Illinois' nuclear plants were truly at risk of retirement, *see* H. K. Trabish, Exelon, ComEd face Illinois clean energy coalition in 3-bill showdown, Utility Dive (Apr. 20, 2015), https://www.utilitydive.com/news/exelon-comed-face-illinois-clean-energy-coalition-in-3-bill-showdown/388399/; P. Maloney, 'Straight uphill': Power sector reforms face tough path in gridlocked Illinois legislature, Utility Dive (Apr. 12, 2016), https://www.utilitydive.com/news/straight-uphill-power-sector-reforms-face-tough-path-in-gridlocked-illin/417215/; S. Daniels, Exelon's downstate nuke gets surprise windfall, Crain's Chicago Business (Apr. 16, 2015), https://www.chicagobusiness.com/article/20150416/NEWS11/150419883/exelon-s-downstate-nuke-gets-surprise-windfall ("One of the three Illinois nuclear plants that Exelon is threatening to close because they're losing money will receive a windfall worth tens of millions beginning in June, courtesy of ratepayers downstate . . . The windfall at Clinton is sure to raise questions about whether Illinois lawmakers should grant special favors to Exelon when it's demonstrating success in persuading regional grid operators and their federal regulators to alter capacity markets in order to funnel more cash to nuclear plants and other generators.").

[75] 20 Ill. Comp. Stat. Ann. 3855/1-75(d-5)(1).

[76] *Id.*

include the Clinton reactor, for which Constellation just filed its 20-year license renewal application.[77]

CEJA supplemented FEJA's nuclear subsidies in response to another round of threatened retirements.[78] The law created carbon mitigation credits, available only from nuclear reactors,[79] and required the Illinois Power Agency ("IPA") to procure five-year contracts for those credits on behalf of certain electric utilities.[80] Like the ZEC contracts, these carbon mitigation credit contracts expire May 31, 2027.[81] CEJA's carbon mitigation credit program was expected to cost ratepayers $700 million, driving that money to Constellation's Braidwood, Byron, and Dresden reactors.[82] **Instead, Constellation earned so much money from those reactors in 2022 that it was required to credit ~$1 billion back to Illinois ratepayers rather than recoup the subsidy.[83]**

Although the legislative design of CEJA's carbon mitigation credit program was informed by an audit that identified financial risk to Constellation's Byron and Dresden plants,[84] even that audit recommended that the program "not extend beyond five years" because the ten-year expected net present values ("NPVs") for Byron, LaSalle, Braidwood, and Dresden (the four plants evaluated in the audit) were all positive.[85] The auditors further cautioned that "any subsidy . . . should be based on each plant's financial need" and "[n]o subsidy should be paid without demonstration of actual need."[86] Notably, this April 2021 audit does not contemplate potential revenues related to 45V tax credits for hydrogen production—those credits did not exist until the IRA's passage over a year later in August 2022.

Operating in the background of these generous state subsidies is CEJA's 100% clean energy target, which will eliminate competition between Constellation's nuclear plants and

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77 Ill. Com. Comm'n, Public Notice of Successful Bidders and Average Prices, Illinois Power Agency January 2018 Procurement of Zero Emission Credits from Facilities Fueled by Nuclear Power, at 3 (Jan. 25, 2018), https://icc.illinois.gov/api/web-management/documents/downloads/public/Public%20Notice%20of%202018%20ZEC%20Procurement%20Results%202018-01-25.pdf.
78 *See, e.g.*, T. Gardner, Illinois approves $700 million in subsidies to Exelon, prevents nuclear plant closures, Reuters (Sept. 13, 2021), https://www.reuters.com/world/us/illinois-senate-close-providing-lifeline-3-nuclear-power-plants-2021-09-13/.
79 20 Ill. Comp. Stat. Ann. 3855/1-75(d-10)(2).
80 *Id.* at 1-75(d-10)(3).
81 *Id.*
82 R. Channick, ComEd carbon credit to lower bills by $20 per month in June, a dividend from bailout of 3 struggling Illinois nuclear plants, Chicago Tribune (Apr. 27, 2022) ("Channick, ComEd Carbon Credit"), https://www.chicagotribune.com/business/ct-biz-comed-carbon-credit-nuclear-plant-bailout-20220428-n6mbuxyt4nh4nnu2pkjd4ocw6e-story.html.
83 Channick, ComEd Carbon Credit.
84 D. Bhandari et al., Exelon Illinois Nuclear Fleet Audit: Findings and Recommendations, Synapse Energy Econ., Inc. (Apr. 14, 2021) ("Bhandari, Exelon Illinois Nuclear Fleet Audit"), https://www.synapse-energy.com/sites/default/files/Exelon_Illinois_Nuclear_Fleet_Audit_Report_REDACTED_21-002.pdf (redactions in original).
85 Bhandari, Exelon Illinois Nuclear Fleet Audit at iii; *see also id.* at 16 (stating that modeling results "suggest[ed] that a decision by the State of Illinois to provide **modest** (e.g., $1.0 and $3.5/MWh), **short-term** (e.g., 5-year) ZECs to Byron and Dresden may be sufficient to keep 95 percent of the expected NPVs positive.") (emphasis added).
86 *Id.* at iii.

Illinois' fossil fuel power plants. CEJA declares that "it is the policy of [Illinois] to rapidly transition to 100% clean energy by 2050."[87] The law requires all fossil fuel plants in Illinois to "permanently reduce all CO_2e and copollutant emissions to zero" by 2045 and requires significant incremental reductions before then (e.g., 45% reduction by 2035).[88] Some plants are required to eliminate their emissions earlier, in 2030 or 2040, squarely within the timeframe when most 45V tax credits will likely be administered.[89] Illinois' transition toward a carbon-free grid bodes well for Constellation, which has cited competition with fossil fuel plants as a key driver of unfavorable economic conditions for its nuclear fleet.[90]

On their own, these state policies and incentives underscore the importance of closely scrutinizing, on a case-by-case basis, any claim that a nuclear reactor would retire unless hydrogen producers who use that reactor's electricity can receive 45V credits. The robust federal subsidies discussed above make it even more important. As explained above, Constellation would be able to recoup the 45U tax credit so long as its annual average "gross receipts" fall under $43.75 per MWh. Price projections from IPA's market price index (energy + capacity) for delivery year June 1, 2023 through May 31, 2024 is $48.60 per MWh.[91]Although this value is based on forward energy market prices that were set prior to the delivery year, it is a useful benchmark for estimating Constellation's average gross receipts. The IPA price index is well in excess of the 45U threshold and does not include state subsidies that would count toward Constellation's average gross receipts. If actual prices approximate IPA's projected prices, then Constellation's average gross receipts would exceed the financial threshold for which federal subsidies have been deemed appropriate.

Taken together, the IRA's and BIL's substantial nuclear subsidies, coupled with the policies in place in Illinois, promise to aid struggling nuclear reactors during many of the same years that 45V credits are available. Data points from Illinois cast doubt on any suggestion that U.S. nuclear reactors need even more subsidies: Constellation has already relicensed (or applied to relicense) most of its reactors for most of the years 45V credits will be available; the company reimbursed ratepayers rather than recoup a state subsidy in 2022; and the company may not qualify for 45U this year based on projected power prices. Outside of Illinois, the fact that only one nuclear plant has yet qualified for the Civil Nuclear Credit program raises further doubts

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[87] 20 Ill. Comp. Stat. Ann. 3855/1-5(1.5).
[88] 415 Ill. Comp. Stat. Ann. 5/9.15(g)–(k).
[89] *Id.* at 9.15(g), (i).
[90] *See, e.g.*, Constellation, Exelon Generation to Retire Illinois' Byron and Dresden Nuclear Plants in 2021, https://www.constellationenergy.com/newsroom/2020/exelon-generation-to-retire-illinois--byron-and-dresden-nuclear-.html#:~:text=Byron%2C%20located%20just%20outside%20Byron,Byron%20for%20another%2020%20years. Bolstering the favorable outlook for Constellation's nuclear plants, a spokesperson for the Pritzker Administration recently stated that "IL will rely heavily on nuclear to reach our carbon-free goals." @JordanAbudayyeh, Twitter (Jan. 24, 2024, 11:21 AM), https://twitter.com/JordanAbudayyeh/status/1750237375207289329.
[91] IPA, Zero Emission Standard, Final Payment Calculation Notice of the Illinois Power Agency, Delivery Year: June 1, 2023 through May 31, 2024 (June 10, 2023), https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/zec-final-pmt-calcs-dy-2023-2024-20230608.pdf.

about the need for more nuclear subsidies.[92] At the very least, these facts make clear that it would be arbitrary for Treasury to create an avoided retirements exemption without carefully scrutinizing whether such an exemption is warranted and what the emissions impact of such an exemption would be.

d. If Treasury allows any avoided retirements exemption for existing nuclear reactors, it must require detailed and case-specific demonstrations.

While an avoided retirements exemption for existing nuclear reactors would be unnecessary and risk significant emissions increases, if Treasury nevertheless decides to create that exemption, it should require a rigorous, fact-intensive, and case-by-case investigation before determining that an existing reactor qualifies. The Illinois case study underscores the importance of conducting such an investigation. Given Treasury's important task of ensuring only those hydrogen production projects that meet the statutory emissions thresholds can access the market-transforming 45V tax credits, it would be sound and responsible federal policy to require companies to meet a high burden of proving that their nuclear reactors would retire but for access to 45V credits when those reactors already have licensing dates long into the future and access to multiple hefty subsidies.

At a minimum, Treasury's rules should require a reactor to be within no more than five years of a subsequent license renewal and to meet a similar economic test to the one required for the Civil Nuclear Credit program. That test requires DOE to evaluate:

> (I) the average projected annual operating loss in dollars per megawatt-hour, inclusive of the cost of operational and market risks, expected to be incurred by the nuclear reactor over the [] period for which [45V] credits would be allocated;[93] (II) any private or publicly available data with respect to current or projected bulk power market prices; (III) out-of-market revenue streams; (IV)

[92] For an example outside of Illinois, Xcel Energy recently announced plans to extend the lives of both of its nuclear plants (Prairie Island and Monticello) in Minnesota, seemingly regardless of eligibility for 45V. *See* Xcel Energy, 2024-2040 Upper Midwest Integrated Resource Plan, Docket No. E002/RP-24-67, at 97 (Feb. 1, 2024) ("Xcel Energy IRP"), https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={A0BD668D-0000-C311-BA08-1136E5F66A42}&documentTitle=20242-203027-01; W. Orenstein, Xcel Energy wants to extend life of Prairie Island nuclear facility, add two gas plants, Star Tribune (Feb. 1, 2024), https://www.startribune.com/xcel-energy-long-term-plan-prairie-island-nuclear-gas-plants-wind-solar-large-scale-battery/600340390/?utm_medium=email&refresh=true. Based on its Integrated Resource Plan filing and its relicensing application for Monticello, it does not appear that eligibility for 45V influenced Xcel's decision to extend the life of its nuclear plants. *See generally Xcel Energy IRP*; *see also* Xcel Energy, Monticello Nuclear Generating Plant Unit 1 Subsequent License Renewal Application, Docket No. 50-263 (Jan. 2023), https://www.nrc.gov/docs/ML2300/ML23009A354.pdf.

[93] In the context of the Civil Nuclear Credit program, the relevant period is the four-year period for which the program's credits would be allocated. In the context of 45V, it would be reasonable to instead consider the period for which EACs from existing nuclear plants would be deemed "incremental" on grounds that the plants would retire but for their relationship to hydrogen production.

> operations and maintenance costs; (V) capital costs, including fuel; and (VI) operational and market risks.[94]

Information on the "average projected annual operating loss" must account for "all projected payments from State programs," such as the nuclear subsidy programs in Illinois created by FEJA and CEJA.[95] Because DOE already must make this assessment when reviewing applications for the Civil Nuclear Credit Program, it may make sense for DOE to oversee any similar assessment for purposes of determining 45V eligibility. Treasury should also set a tight, hourly limit on the amount of electricity from a reactor that could qualify for the exemption (e.g. no more than 5% per hour) to reflect the fact that the decision to continue operating a nuclear reactor will invariably be determined by a wide range of factors other than 45V. Setting these strict criteria around any potential avoided retirements exemption would mitigate the risk of the exemption becoming a massive loophole that allows highly carbon-intensive hydrogen to qualify for 45V credits.

2. A 5–10% formulaic approach to addressing incrementality would arbitrarily create a very high risk of induced grid emissions.

As discussed above and acknowledged by Treasury, weakening any of the three pillars would cause induced grid emissions that have serious, detrimental consequences for the climate and for communities that host power plants, many of which are already overburdened. This is true of the potential formulaic approach that "would deem five percent of the hourly generation from minimal-emitting electricity generators (for example, wind, solar, nuclear and hydropower facilities) placed in service before January 1, 2023 as satisfying the incrementality requirement."[96] An exemption at the 5% level would induce legally significant emissions and unjustifiably harm communities and the climate. These consequences would be even worse if Treasury exempted "up to 10 percent" of generation from demonstrating incrementality, as contemplated. These consequences would undermine the purpose and effectiveness of the 45V tax credit and grossly outweigh any administrative benefits that might be gained. Available data and analysis demonstrate that the formulaic approach is arbitrary and unreasonable.

The formulaic approach is offered as a "proxy" for other potential exemptions to the incrementality requirement, including where the energy demands of hydrogen production are met by renewable energy that would otherwise be curtailed, where "minimal-emitting electricity generation is on the margin," and where such demands cause a nuclear plant to avoid retirement.[97] The 5% proposal appears to be loosely based on data on curtailment rates in renewable energy sectors: an average curtailment rate of 5.3% for wind in 2022, and a solar photovoltaic curtailment rate of over 10% in Electric Reliability Council of Texas ("ERCOT") territory and over 3% in California Independent System Operator ("CAISO") territory. Treasury

[94] 43 U.S.C. § 18753(c)(1)(A)(i).
[95] *Id.* § 18753(c)(1)(C).
[96] 88 Fed. Reg. at 89,231.
[97] *Id.* at 89,231.

also notes that negative wholesale energy prices "occurred during roughly five percent of hours over the last several years."[98]

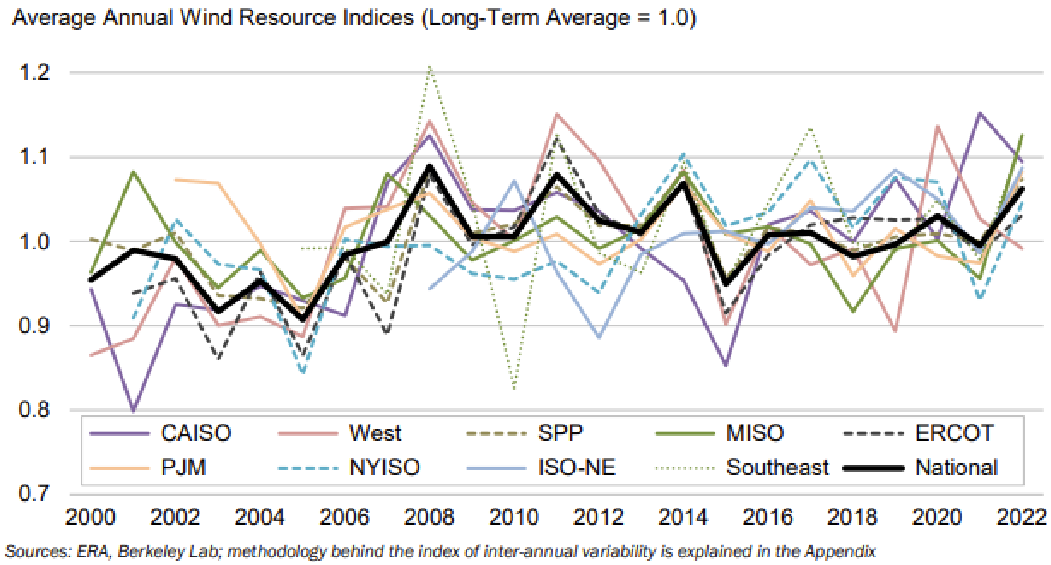
A fundamental problem with such a formulaic approach is that it is highly likely that significant portions of a 5 or 10% allowance would be used to satisfy the incrementality pillar at times and in locations where renewable energy is not being curtailed. In these conditions, renewable energy diverted for hydrogen production would be replaced by dirty, carbon- and pollution-intensive energy sources. Not only do curtailment rates vary dramatically over time and across plants and regions,[99] but curtailment occurs in just a few hours of the year in any particular region. In concluding that negative wholesale prices occurred during "roughly five percent of hours over the last several years," Treasury cites data from the Lawrence Berkeley National Laboratory that shows negative wholesale pricing in as few as 2.3% of hours in 2018 and as many as 6.3% of hours in 2022.[100] It would be illogical and dangerous to create an exemption that is motivated by the rare conditions that lead to curtailment and allow hydrogen producers to take advantage of that exemption when those rare conditions do not exist.

Variability in the curtailment of wind resources illustrates why it would be irrational to assume otherwise-curtailed renewable resources would be available when and where profit-maximizing hydrogen producers invoke a blanket 5–10% exemption. The DOE report Treasury cites for the 5.3% average wind curtailment rate in 2022 explicitly states that "this average masks variations across regions and projects."[101] The report finds that in 2022, average regional curtailment rates were as high as 9.2% in the Southwest Power Pool and below 2% in three other independent system operators ("ISOs").[102] The report also observes that curtailment rates vary significantly across years, including because, "in areas where curtailment has been acute in the past, steps taken to address the issue have often borne fruit." The report references ERCOT where wind energy curtailment went from 17% in 2009 to 0.5% in 2015 as a result of measures taken to minimize it.[103] Given this, it is highly likely that any set allowance will be inaccurate at implementation and even more inaccurate over the ten-year lifespan of the tax credit.

Wind resources also vary substantially across years, as illustrated by the following graph from DOE's report:[104]

[98] *Id.* at 89,231–32.
[99] *Id.*
[100] *Id.* at 89,232.
[101] Office of Energy Efficiency & Renewable Energy, DOE, Land-Based Wind Market Report: 2023 Edition, at x (Aug. 24, 2023) (attached), https://www.energy.gov/sites/default/files/2023-08/land-based-wind-market-report-2023-edition.pdf.
[102] *Id.*
[103] *Id.*
[104] *Id.* at 41, Figure 39.

Figure 1: Inter-Annual Variability in the Wind Resource by Region and Nationally



Per DOE, wind curtailment rates also vary significantly inter-annually: "from site to site (and, hence, also region to region) . . . inter-annual variation has, at times, exceeded +/-20% at the regional level."[105]

Substantial variations in curtailment across time and regions are not peculiar to wind. A 2018 DOE study determined that solar photovoltaic curtailment in CAISO increased from 0.8% in 2015 to 1.5% in 2018. In 2018, ERCOT's solar photovoltaic curtailment rate was 8%, over five times that of CAISO's.[106] The same study found significant variations across regions in the percentage of hours seeing negative pricing of hourly locational marginal price ("negative LMP"), periods of time where minimal-emitting electricity generation is more likely to be on the margin. In 2018, there were zero hours of negative LMP in MISO while CAISO experienced negative LMP during 2.1% of hours.[107]

Likewise, data on negative wholesale pricing shows wide variability across the United States and across years and individual days, indicating wide variability in curtailment across regions and time periods.[108] The map below reveals that negative pricing frequency in 2022 varied between 0% of hours and greater than 20% of hours across regions of the country.

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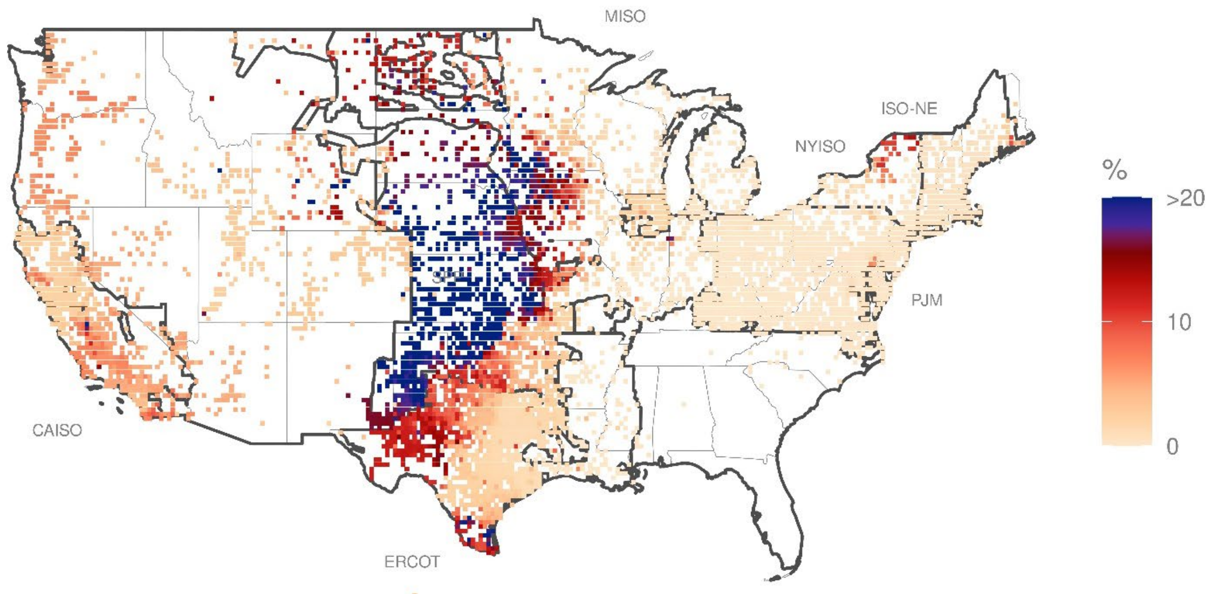
[105] *Id.*

[106] Off. of Energy Efficiency & Renewable Energy, DOE, 2018 Renewable Energy Grid Integration Data Book, at 9 (Feb. 2020), https://www.nrel.gov/docs/fy20osti/74823.pdf, (attached).

[107] *Id.*

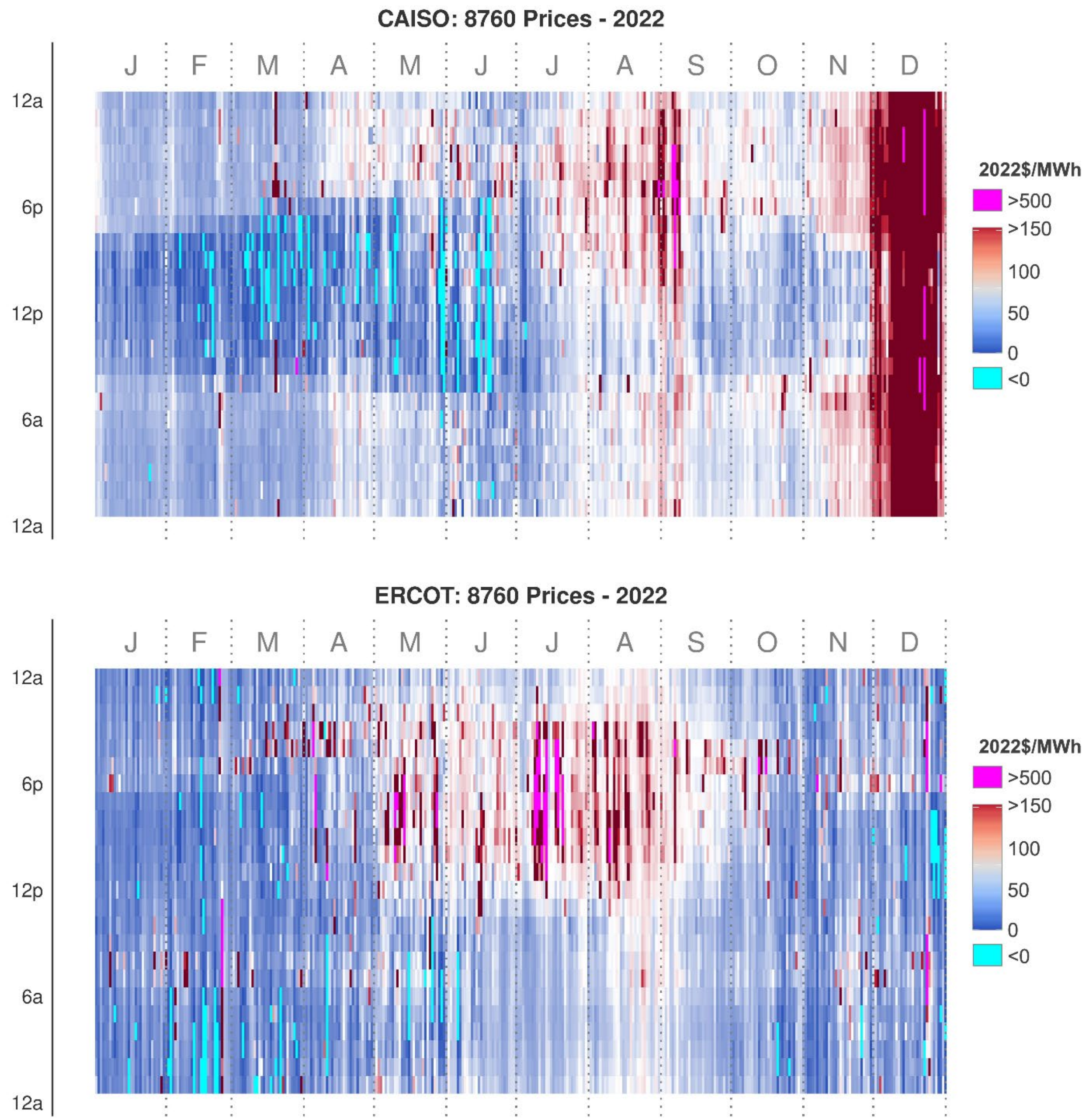
[108] All three images are taken from: Berkeley Lab, Elec. Mkts. & Pol'y, The Renewables and Wholesale Electricity Prices (ReWEP) Tool, https://emp.lbl.gov/renewables-and-wholesale-electricity-prices-rewep (providing graphics derived from the Lawrence Berkeley National Laboratory data).

Figure 2: Negative Pricing Frequency in the United States, 2022



As Figure 3 shows, in 2022 in both CAISO and ERCOT there were substantial variations in negative pricing rates depending on the time of year and time of day. A flat 5-10% allowance would have serious climate consequences because it fails to account for any of these variations. Such an approach would improperly ignore the significant induced grid emissions of hydrogen producers who invoke the exemption when there is no negative pricing and local conditions indicate that additional load will be served by polluting resources.

Figure 3: CAISO and ERCOT Wholesale Energy Prices, 2022.



Given these realities, use of an allowance that is uniform across plants, regions, time of day/year, and the ten-year lifetime of the 45V tax credit would be unsupported by evidence, arbitrary, and highly likely to result in large, induced grid emissions. According to the Rhodium Group, an approach that allows 5% of renewable energy to be "diverted during the dirtiest hours on the grid . . . could cause a huge increase in systemwide emissions—up to nearly 1.5 billion metric tons of increased emissions cumulatively through 2035."[109] Such a blanket allowance would practically ensure high induced grid emissions as hydrogen producers are most likely to

[109] Rhodium Grp., How Clean Will US Hydrogen Get?

make use of the allowance during times when there is a scarcity of new, additional clean energy and—consequently—a scarcity of EACs that satisfy all three pillars.

3. It would be inappropriate to adopt an exemption that attempts to target otherwise-curtailed resources because the risks of unintended consequences outweigh the exemption's limited utility.

Treasury observes that one circumstance in which diversion of existing zero-emission generation to hydrogen production may not significantly induce GHG emissions is "during periods in which minimal-emitting generation would have otherwise been curtailed, if marginal emissions rates are minimal."[110] However, the risks of gaming and other unintended consequences make it imprudent to adopt an exemption targeting otherwise-curtailed generation.

The risk of gaming by fossil fuel generators arises in regions where generators can self-schedule. Self-scheduled, polluting generators can run even when their operation is uneconomic, including when energy prices drop to or below $0/MWh. Most often, the units that operate due to self-scheduling are coal-fired units.[111] Consequently, a self-scheduled coal unit can ramp up to meet additional load when there are low or negative local node or zonal prices. The $3/kg tax credits are so lucrative that they can create an economic incentive for hydrogen producers to collude with coal-fired generators, who can profitably sell electricity into a wholesale market for $0/MWh if they receive sufficient payment from hydrogen producers through alternative channels. That is, hydrogen producers will have a willingness to pay for purportedly zero-emission electricity[112] that far exceeds the $36/MWh median cost of operating a coal-fired generator.[113]

There is also a risk of gaming when a regulated utility or merchant generator owns both fossil generators and hydrogen production facilities. It may be infeasible for Treasury to determine when a power plant owner has self-scheduled a carbon-emitting facility to generate tax revenues for its hydrogen production facilities. Treasury should not adopt any exemption that presents gaming risks without effective measures for preventing, monitoring, and penalizing such abuses.

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[110] 88 Fed. Reg. at 89,230.

[111] An empirical analysis indicated that the volume of self-committed megawatts (of all fuel types) decreased in Southwest Power Pool ("SPP") between March 2014 and August 2019 but still represented nearly half of the energy generated in SPP. Energy generation from coal self-commitments dominated over other self-committed fuels by a factor of more than four to one. SPP Mkt. Monitoring Unit, Self-committing in SPP markets: Overview, impacts, and recommendations, at 18, Figure 4-3 (Dec. 2019), https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

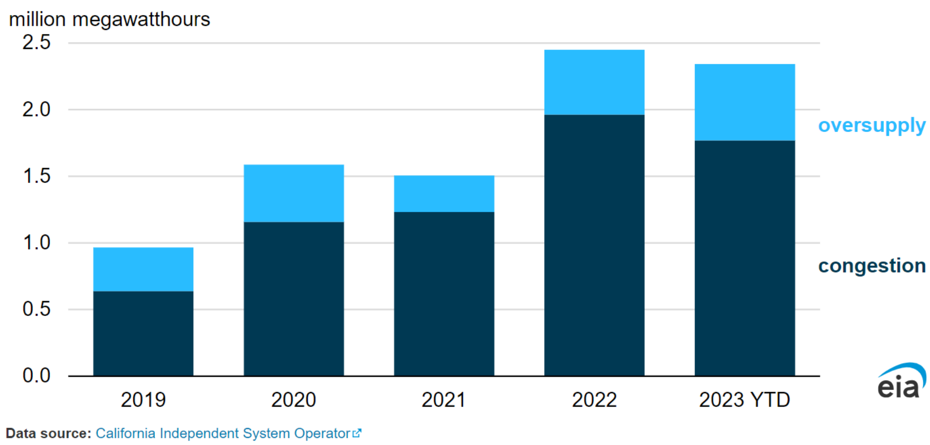
[112] For instance, in a scenario with mid-range electrolyzer cap-ex costs, electrolytic hydrogen producers will be able to produce hydrogen with a levelized cost (post-subsidy) of just $1/kg, even if they pay $60/MWh and operate with a 70% capacity factor. W. Ricks & J. Jenkins, The Cost of Clean Hydrogen with Robust Emissions Standards: A Comparison Across Studies, Princeton University, at 7, Figure 4 (Apr. 19, 2023), https://zenodo.org/records/7838874.

[113] Z. Budryk, 99 percent of US coal plants are more expensive than new renewables would be: report, The Hill (Jan. 30, 2023), https://thehill.com/policy/energy-environment/3836301-99-percent-of-u-s-coal-plants-are-more-expensive-than-new-renewables-would-be-report/.

It would be particularly unwise for Treasury to adopt an exemption targeting otherwise-curtailed zero-emission resources, when such an exemption is unlikely to support significant additional clean hydrogen production. This is because a hydrogen producer that is eligible for the $3/kg tax credit will typically maximize profits by overbuilding new incremental zero-emission resources—leading to **more** excess energy in the hours when renewable energy is most abundant in the producer's region. For instance, NextEra Energy Resources is developing a green hydrogen production project that pairs 100 MW of electrolysis capacity with 450 MW of dedicated renewable energy generation.[114] Given the limited utility of an exemption for otherwise-curtailed resources, Treasury should not risk the potentially significant unintended consequences of the contemplated exemption.

If Treasury decides to target at an exemption at otherwise curtailed-resources despite its risks and questionable benefits, it must include guardrails to reduce unintended consequences. One essential guardrail on any exemption for avoided curtailment would be limiting it to hydrogen producers whose electricity prices are negative at their local node or pricing zone. Negative prices and curtailment elsewhere in a deliverability region or balancing authority is not evidence that a facility's increased energy demands are reducing curtailment because curtailment often occurs due to transmission constraints within balancing areas preventing the delivery of renewables to load centers—not insufficient demand. For instance, in CAISO, most renewable curtailment results from congestion rather than oversupply, as the following figure illustrates:[115]

Figure 4: CAISO curtailment, by cause (2019–2023)



Relying on local pricing node or zone data would help identify the periods when there is an oversupply of zero-emission generation that can be delivered to the facility. When congestion is causing curtailment, an electrolyzer's additional energy demand will not reduce curtailment if transmission bottlenecks prevent the delivery of the curtailed renewables to the hydrogen production facility. During these periods, increasing the electrolyzer's energy demand will likely

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[114] CF Industries, CF Industries and NextEra Energy Resources Announce Green Hydrogen Project MOU to Support Ag Supply Chain Decarbonization (Apr. 24, 2023), https://www.cfindustries.com/newsroom/2023/cf-nextera-mou-green-hydrogen.

[115] EIA, Solar and wind power curtailments are rising in California (Oct. 30, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60822.

trigger significant GHG emissions, as the marginal fossil-fueled units serving the facility's specific area ramp up to meet its demand. Treasury should also require hydrogen producers to demonstrate that locational marginal emissions were zero during the periods they seek to apply the exemption, with evidence such as third-party certification.[116] While the risks of gaming make it imprudent for Treasury to adopt an exemption for otherwise-curtailed resources, Treasury should consider these guardrails if it nonetheless adopts this exemption.

4. It would be inappropriate to adopt an exemption for hydrogen producers where state policies prevent new load from increasing grid emissions because there is no evidence that such policies will be in effect when 45V tax credits are available.

Treasury seeks comment on when state policies could demonstrate that incrementality is unnecessary for avoiding significant GHG emissions from new load.[117] Such an exemption threatens to open an enormous loophole in Treasury's careful efforts to ensure it only awards 45V tax credits for hydrogen production that meets the statutory lifecycle GHG emissions thresholds. The danger is clear because some stakeholders have argued against an incrementality requirement by citing state policies that will not prevent new load from dramatically spiking GHG emissions. Indeed, it is uncertain whether any state will have policies in place before 2045 that ensure zero-GHG electricity meets new load. Therefore, an incrementality exemption based on state policies could create opportunities for abuse, without playing any useful role in Treasury's implementation of Section 45V.

The Alliance for Renewable Clean Hydrogen Energy Systems ("ARCHES"), California's hydrogen hub, provides one example of how stakeholders have incorrectly argued that current state policies justify waiving an incrementality requirement. Specifically, ARCHES has argued that "[a]dditionality should not be required for jurisdictions with Renewable Portfolio Standards and clear commitments to decarbonize all sectors of the economy."[118] In California, the two policies that ARCHES cites—the Renewable Portfolio Standard ("RPS") and the statewide GHG goals—are insufficient to ensure new electricity demand for hydrogen production will be provided by zero-carbon resources. Indeed, ARCHES does not claim that California hydrogen producers could meet the statutory carbon intensity thresholds without the buildout of incremental zero-GHG resources. Rather, ARCHES complains that an additionality requirement would impact the timeliness and cost of project deployment,[119] factors that are irrelevant to determining whether new generation is necessary to avoid significant emissions. Taking state

[116] For example, the company REsurety sells access to data on "Locational Marginal Emissions (LMEs) [that] are calculated at each power system node in a manner very similar to the Locational Marginal Prices (LMPs) used to set wholesale electricity market prices. LMEs measure emissions by identifying the marginal generators." REsurety, Measure and maximize carbon impact with Locational Marginal Emissions, https://resurety.com/solutions/locational-marginal-emissions/.

[117] 88 Fed. Reg. at 89,231.

[118] Comments of ARCHES, Letter to Internal Revenue Service Re: Notice 2022-58 – Response to Request for Comments on Credits for Clean Hydrogen (H_2) and Clean Fuel Production, Comment ID No. IRS-2022-0029-0238, at 2 (Aug. 23, 2023).

[119] *Id.*

policy into account, independent researchers have determined that an additionality requirement is necessary to reduce consequential emissions from California electrolytic hydrogen production below 4 kg CO_2/kg H_2.[120] Indeed, hydrogen producers who rely on the California grid without deploying additional zero-emissions resources will produce hydrogen with consequential emissions of about 19 kg CO_2/kg H_2.[121]

The first fundamental reason why California's RPS and statewide decarbonization goals do not affect the need for an incrementality requirement is that their most stringent targets do not take effect until **after** the expiration of Section 45V's tax credits. Section 45V provides tax credits for the ten-year period after a hydrogen production facility is placed in service and is only available to facilities that begin construction prior to January 1, 2033.[122] Consequently, modelers predict that Section 45V will only incentivize hydrogen production through 2044.[123] Meanwhile, California's RPS does not require renewable energy and zero-carbon resources to supply 100% of the state's retail electricity sales until December 31, 2045.[124] California's economy-wide decarbonization policy is to "[a]chieve net zero greenhouse gas emissions as soon as possible, but no later than 2045, and to achieve and maintain net negative greenhouse gas emissions thereafter."[125] Thus, even if California's current policies could obviate the need for an incrementality requirement once they take effect, that is not required to happen in the relevant timeframe.

Second, even after California's most stringent RPS target takes effect, it will not be sufficient to prevent significant emissions from new electrolyzer demand. California's RPS requires renewable and zero-carbon resources to supply "100 percent of all retail sales of electricity to California end-use customers" by the end of 2045.[126] The state agencies responsible for implementing the RPS have interpreted this requirement to allow utilities and other load-serving entities to continue procuring electricity from carbon-emitting resources indefinitely to meet certain vital system needs. Under the agencies' interpretation, the 100% RPS mandate requires renewable and zero-carbon energy procurements to match the number of megawatt-hours sold to end users, but does not restrict procurements for the significant amount of energy lost to transmission and distribution line losses or energy storage losses.[127] As discussed in section II.D., the emissions associated with line losses alone are great enough to render

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[120] Princeton Three Pillars Study at PDF p. 35 (Supplementary Figure 19) (showing that hydrogen produced in the Southern California zone without an additionality requirement will have consequential emissions of 19 kg CO_2/kg H_2, even if a 100% hourly matching requirement is in place).
[121] *Id.*
[122] 26 U.S.C. §§ 45V(a)(1), (c)(3).
[123] *See, e.g.*, EPRI 45V Paper at 15, Figure 3.
[124] Cal. Pub. Util. Code § 454.53(a).
[125] Cal. Health & Safety Code § 38562.2(c)(1).
[126] Cal. Pub. Util. Code § 454.53(a).
[127] CEC et al., 2021 SB 100 Joint Agency Report, at 59 (Mar. 15, 2021) https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349 ("SB 100 speaks only to retail sales and state agency procurement of electricity. The joint agencies interpret this to mean that other loads — wholesale or nonretail sales and losses from storage and transmission and distribution lines — are not subject to the law.").

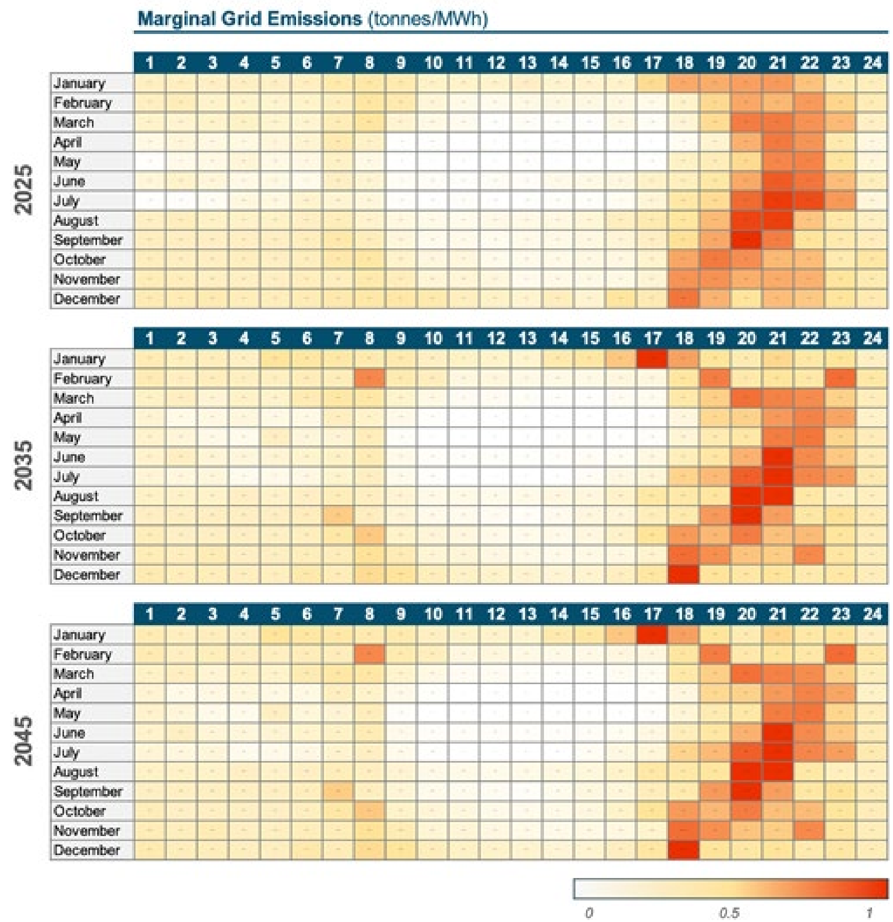
electrolytic hydrogen ineligible for the 45V tax credits if the lost energy is supplied by fossil-fueled power plants.

Likewise, even in 2045, California's statewide carbon neutrality goal would not render an incrementality requirement unnecessary. In its 2022 Scoping Plan for Achieving Carbon Neutrality, the California Air Resources Board ("CARB") plans for the state to continue emitting 72 MMT of CO_2e in 2045 and offset those emissions through strategies like direct air capture of carbon dioxide and sequestering carbon in natural and working lands.[128] Any strategies California might deploy to offset a hydrogen producer's emissions and achieve statewide carbon neutrality do not affect Treasury's duty to determine eligibility for Clean Hydrogen Production Tax Credits based on a hydrogen producer's lifecycle GHG emissions. The statutory definition of "lifecycle greenhouse gas emissions" includes aggregate emissions "related to the full fuel lifecycle," but does not include emissions-reductions measures that are unrelated to the fuel.[129] Further, Section 45V makes clear that hydrogen producers are only eligible for tax credits if their hydrogen is "produced through a process that results in a lifecycle greenhouse gas emissions rate" below the statutory thresholds.[130] It would be inconsistent with the statute to ignore the emissions from hydrogen production in California because other state entities are deploying direct air capture equipment or sequestering carbon in working lands.

These policy gaps explain why modeling for the California Energy Commission ("CEC") shows very limited change in marginal emission rates between now and 2045. The following figure shows marginal grid emissions factors developed for a CEC study on the role of long-duration energy storage in the state:[131]

[128] CARB, 2022 Scoping Plan for Achieving Carbon Neutrality, at 96, Table 2-3 (Dec. 2022), https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.
[129] 42 U.S.C. § 7545(o)(1).
[130] 26 U.S.C. § 45V(b)(2).
[131] CEC, Assessing the Value of Long-Duration Energy Storage in California, at 17, Figure 7 (Dec. 2023), https://www.energy.ca.gov/sites/default/files/2024-01/CEC-500-2024-003.pdf.

Figure 5: Estimated CAISO Marginal Grid Emissions



Given that California's state agencies expect current trends in marginal grid emissions to persist through 2045, it would be unreasonable for Treasury to assume hydrogen production on California's grid will not lead to significant emissions. While marginal grid emissions may decline in some hours, there is no evidence that these declines will be sufficient to reduce the consequential emissions from hydrogen production from today's 19 kg CO_2/kg H_2 to a level that is consistent with claiming a tax credit under Section 45V.

Waiving the incrementality requirement in California would not only lead to emissions that are inconsistent with the plain requirements of Section 45V—it would also be devastating for consumers. Several ratepayer advocate groups joined a broad coalition of environmental and environmental justice stakeholders in opposing ARCHES' efforts to weaken implementation of Section 45V because of the potential for hydrogen production to drive up electricity rates in a state that already faces an energy affordability crisis.[132] These advocates specifically warn that

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[132] Asian Pac. Env't Network et al., Letter to Governor Newsom, Re: Concern Regarding ARCHES' efforts to weaken vital protections for 45V tax credits, at 3–4 (Feb. 12, 2024), https://static.politico.com/2f/90/1afdd26e4561918c93caaf53fa83/feb-2024-45v-advocates-letter-to-gov-newsom.pdf (attached).

hydrogen production in California could spike wholesale electricity and capacity prices unless it adheres to all three pillars.

Likewise, despite being a climate leader, Washington State has not adopted policies that could justify an exemption from the incrementality requirement. Washington has a policy requiring that "all retail sales of electricity to Washington retail electric customers be GHG-neutral by January 1, 2030."[133] However, until December 31, 2044, utilities can satisfy up to 20% of this obligation by making a monetary payment in lieu of supplying zero-carbon electricity.[134] Industry has argued that the law allows the utilities to continue procuring carbon-emitting electricity indefinitely, on the theory that energy lost to line losses and storage losses are distinct from retail sales. This question has not been resolved by state regulators or courts. Consequently, in the period when tax credits will be available under Section 45V, **at least** 20% of grid energy may be supplied by carbon-emitting resources. Introducing new load from hydrogen production threatens to increase emissions from those facilities.

The inability of state policy to avoid a need for an incrementality requirement is not unique to California or Washington. According to the National Conference of State Legislatures' catalog of renewable portfolio standards, only four jurisdictions have 100% targets that take effect prior to 2045: Minnesota (2040), New York (2040), Rhode Island (2033), and the District of Columbia (2032).[135] In all four of these jurisdictions, the 100% standard is explicitly tied to the percentage of retail sales or demand,[136] raising the risk that polluting power plants will ramp up as load increases to provide energy for line losses and energy storage losses. New York, Rhode Island, and the District of Columbia's policies provide offramps from compliance, making it improper for Treasury to assume future compliance.[137] In addition, Oregon has a clean energy target that aims to reduce electric utilities' GHG emissions 100% below a baseline level by 2040, but Oregon's statute provides exemptions from this target to contain costs and ensure reliability.[138] Crucially, it is unclear whether any of these states have policies that ensure delivery of carbon-free electricity to their load centers will not induce emissions elsewhere. In this policy landscape, it would be unreasonable for Treasury to find that any state policies can make an incrementality requirement unnecessary, as examples of such policies simply do not exist.

In the absence of policies that do what DOE advised is necessary to support an incrementality exemption—that is, "ensure that total GHG emissions are capped with sufficient

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[133] Wash. Rev. Code Ann. § 19.405.040(1) (West 2019).
[134] *Id.* § 19.405.040(1)(b)(i).
[135] Nat'l Conf. of State Legislatures, State Renewable Portfolio Standards and Goals, https://www.ncsl.org/energy/state-renewable-portfolio-standards-and-goals (last updated Aug. 13, 2021).
[136] Minn. Stat. Ann. § 216B.1691, Subdivision 2g (West 2023); N.Y. Pub. Serv. Law § 66-p(2); 39 R.I. Gen. Laws § 39-26-4(a)(14) (West 2022); D.C. Code Ann. § 34-1431(11) (West 2019).
[137] N.Y. Pub. Serv. Law § 66-p(4) (allowing the Public Service Commission to temporarily suspend or modify obligations if it makes certain findings related to safety, arrears, or other factors); Nat'l Conf. of State Legislatures, State Renewable Portfolio Standards and Goals, https://www.ncsl.org/energy/state-renewable-portfolio-standards-and-goals (describing cost caps in the Rhode Island and District of Columbia RPS policies) (last updated Aug. 13, 2021).
[138] Or. Rev. Stat. Ann. §§ 469A.410(a)(c), 469A.445, 469A.440 (West 2021).

effectiveness and stringency to require that new load is met with zero-GHG electricity"[139]—Treasury should avoid unintended consequences by not adopting an exemption. There is a risk that Treasury rules drafted in anticipation of hypothetical circumstances will incorrectly identify state policies as requiring a fully zero-emission grid. After all, even when state legislators intend to require a full transition of polluting resources in the electric sector, implementation decisions and noncompliance can thwart their policy objectives.[140] In the future, if states adopt specific policies that effectively prevent new grid load from increasing GHG emissions, Treasury can make an informed decision on how to craft an exemption that accounts for these policies.

Any state policy would need to meet strict criteria to "ensure that total GHG emissions are capped with sufficient effectiveness and stringency to require that new load is met with zero-GHG electricity." For instance, the state policy would need to explicitly apply to all generation on the electric grid, including generation that backfills for line losses and storage losses. The state would need a mechanism for ensuring that meeting its energy needs with zero-emission electricity would not raise emissions elsewhere. Ironically, this criterion would generally be met with a requirement to procure zero-emission energy from new generation resources. In addition, the emissions cap must apply specifically to emissions from the electric grid. For purposes of Section 45V, it would be unacceptable for a state to claim that it is zeroing out grid emissions through some sort of offset scheme. Moreover, Treasury should not consider any state emissions cap effective unless there is a clear and meaningful enforcement mechanism in place. This enforcement mechanism should include penalties sufficient to deter noncompliance.

In addition, it would be improper to grant any exemption based on state policies that allow "minimal" emissions. Treasury's Proposed Rule discusses the possibility that a grid powered entirely by "minimal-emitting generation" might not induce significant GHG emissions.[141] However, according to the DOE white paper that Treasury relies on for its conclusion that hydrogen producers may sometimes rely on existing generation without causing significant induced GHG emissions: "Such conditions could potentially include locations where grid electricity is 100% generated by zero-GHG generators or where state policies ensure that total GHG emissions are capped with sufficient effectiveness and stringency to require that new load is met with zero-GHG electricity."[142] Treasury must not conflate "minimal emitting" generators with "zero-GHG" generators because only zero-GHG generators are likely capable of

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[139] DOE, Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit, at 10, https://www.energy.gov/sites/default/files/2023-12/Assessing_Lifecycle_Greenhouse_Gas_Emissions_Associated_with_Electricity_Use_for_the_Section_45V_Clean_Hydrogen_Production_Tax_Credit.pdf.

[140] For instance, the California legislators that enacted the state's 100% RPS target likely expected that their legislation would ensure all grid electricity in the state would come from carbon-free generation because it refers to "a transition to a zero-carbon electric system." Cal. Pub. Util. Code § 454.53(a). Nonetheless, the California agencies responsible for implementing this provision interpret it to allow polluting facilities to remain on the grid indefinitely to supply energy commensurate with line losses and storage losses, as discussed above.

[141] 88 Fed. Reg. at 89,230.

[142] *Id.*; DOE, Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit, at 10, https://www.energy.gov/sites/default/files/2023-12/Assessing_Lifecycle_Greenhouse_Gas_Emissions_Associated_with_Electricity_Use_for_the_Section_45V_Clean_Hydrogen_Production_Tax_Credit.pdf.

supporting hydrogen production that qualifies for 45V tax credits. As discussed in section III.B.2 below, hydrogen is unlikely to properly qualify for 45V tax credits if electrolyzers rely on a grid with carbon-emitting generators such as fossil-fueled facilities equipped with carbon capture and sequestration ("CCS") technology.

D. Treasury's Proposed Approach to Hourly Matching Should Not Be Weakened in the Final Rule.

Treasury is proposing to phase in an hourly matching requirement, based on DOE's advice that "hourly matching is necessary to properly address significant indirect emissions from electricity use."[143] DOE's conclusions regarding the significant emissions that could result from a failure to implement an hourly matching requirement are consistent with the findings of independent researchers.[144] Treasury's proposal to phase in its hourly matching requirement in 2028 reflects a conservative timeline for developing an appropriate tracking system, given the results of Treasury's survey of tracking system operators. Of the five respondents who would need to develop an hourly tracking system from scratch, four said that it would take >1–2 years, while the fifth reported that it would take 3–5 years and "closer to three years if there is full state agency buy-in, clear instructions are received from federal or state agencies, and funding for stakeholder participation is available."[145] The clear direction in Treasury's proposal and sharing of best practices among regions will help avoid a worst-case scenario in which tracking system development takes any region longer than three years.

Recent remarks by the director of one electricity tracking system—the Western Renewable Energy Information System ("WREGIS")—reveal the wisdom of Treasury's approach. WREGIS Director Andrea Coon explained that there is currently a chicken-and-egg problem, in which policymakers face questions about adopting an hourly matching requirement in the absence of a suitable tracking system and entities like WREGIS have difficulty developing a system without clear policy direction.[146] Ms. Coons explained that "it's so much easier to get the program out in front first and build to accommodate it." Ms. Coons also opined that developing a tracking system for Treasury's proposed 2028 phase-in is probably doable, but warned that challenges could arise if they had to retrofit software to keep up with a changing policy landscape.[147] Treasury should adopt a clear hourly matching requirement with a 2028 phase-in to provide certainty and direction to the entities that develop electricity tracking software tools.

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143 88 Fed. Reg. at 89,233.
144 *See, e.g.*, Princeton Three Pillars Study at PDF pp. 7–8.
145 88 Fed. Reg. at 89,233.
146 Cal. Hydrogen Bus. Council ("CHBC"), CHBC Webinar Carbon Accounting and the 45V Tax Credit, YouTube (Jan. 26, 2024), https://www.youtube.com/watch?v=OTQXLhIg-HI (discussion beginning around minute 58:00).
147 Ms. Coons' opinion that WREGIS could meet Treasury's proposed timeline is especially noteworthy, given her uncertainty regarding whether WREGIS would be asked to develop tracking systems for two different products—electricity and hydrogen. *Id.* (discussion beginning around 53:20). It is our understanding that Treasury will be responsible for tracking clean hydrogen and that WREGIS and its peer institutions would only be responsible for tracking EACs. If Treasury clarifies that WREGIS would not be responsible for tracking hydrogen, there should be even more cushion in her anticipated timeline for developing the necessary systems.

E. Treasury's Proposed Approach to Deliverability Should Not Be Weakened in the Final Rule.

To the extent feasible, Treasury should define deliverability regions in a manner that matches the operation of the power grid so that the facilities generating EACs displace marginal generating units that are as emissions intensive as the ones the hydrogen producers are actually relying on. As researchers at Princeton University explain, transmission constraints can lead to significant consequential emissions because different marginal units can supply power on different sides of a transmission bottleneck and affect capacity retirements and additions in the long run.[148] Therefore, deliverability regions should be internally well-connected.[149] Although the grid "is not divided neatly into well-connected zones with perfect internal deliverability,"[150] Treasury has identified a readily administrable option: regions that DOE defined in consideration of transmission constraints, which often match power-system operations.[151] Although these regions are broader than the balancing areas that Earthjustice and Sierra Club have recommended as the level of spatial granularity for deliverability regions,[152] Treasury's proposal appropriately accommodates the unique implementation needs of this federal tax credit.

III. TREASURY MUST ACCOUNT FOR ALL DIRECT AND SIGNIFICANT INDIRECT EMISSIONS FROM HYDROGEN PRODUCERS' ELECTRICITY USE.

A. When Electrolytic Hydrogen Producers Use EACs to Demonstrate 45V Eligibility, Those EACs Should Match Both On-Site Energy Demand and Line Losses.

Treasury should account for transmission and distribution line losses when a hydrogen producer uses EACs to substantiate purchase of zero-carbon electricity.

According to the EIA, an average of about 5% of the electricity transmitted and distributed in the United States each year is lost in transit.[153] The practical result of these line losses is that electric generators must generate extra electricity to make up for the lost amount—for example, a generator needs to generate **more** than one megawatt hour of electricity in order to deliver one megawatt hour of electricity to the customer.

The GHG emissions associated with these line losses can be significant. According to a 2016 report from DOE, electricity-related line losses account for about 120 MMT CO_2e each

[148] Princeton Three Pillars Study at PDF p. 10.
[149] *Id.* at PDF p. 11.
[150] *Id.*
[151] 88 Fed. Reg. at 89,233.
[152] Comments of Earthjustice et al., Re: Notice 2022-58, Request for Comments on Credits for Clean Hydrogen and Clean Fuel Production – Earthjustice, Sierra Club, and League of Conservation Voters Comments on Implementing Section 45V, Comment ID No. IRS-2022-0029-0082, at 7 (Dec. 2, 2022).
[153] *See* EIA, Frequently Asked Questions (FAQS): How much electricity is lost in electricity transmission and distribution in the United States?, https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 (last updated Nov. 7, 2023).

year in the United States.[154] A more recent study of line loss emissions at a more granular level found that, within individual NERC regions, emissions due to line losses range from below 8 MMT CO_2e per year to over 24 MMT CO_2e per year,[155] the higher of which is equivalent to the annual CO_2e emissions from roughly 6.5 coal-fired power plants.[156]

The significant emissions associated with line losses mean that even small losses could reduce the amount of 45V credits for which electrolytic hydrogen producers qualify. For example, if a coal plant provides the extra electricity to make up for the amount of electricity lost in transit, then line losses as low as 1% would make electrolytic hydrogen too carbon intensive to qualify for the top-tier $3/kg H_2 credit.[157] Likewise, if a gas-fired combined cycle plant provides that extra electricity, then line losses of less than 2.5% could propel electrolytic hydrogen production past the top-tier emissions threshold.[158]

Treasury must account for these emissions due to line losses in determining 45V eligibility. As discussed above, the lifecycle GHG emissions rate of electrolytic hydrogen production must include "significant indirect emissions," such as induced grid emissions. Emissions associated with line losses are induced grid emissions. Therefore, hydrogen producers should be required to procure enough three-pillar compliant EACs to cover both their on-site electricity demand as well as the amount of electricity lost in transit. As Energy Innovation observes, "[l]osses would be easy to offset, as electrolyzers need only procure slightly more electricity from their paired clean energy resources."[159]

To administer this requirement, Treasury could preset transmission line loss rate assumptions for each interconnection or region and give producers the option of proving that their line losses are lower through verifiable documentation.[160]

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[154] DOE, Environment Baseline, Volume 1: Greenhouse Gas Emissions from the U.S. Power Sector, at 23 (June 2016), https://www.energy.gov/policy/articles/environment-baseline-vol-1-greenhouse-gas-emissions-us-power-sector.

[155] L. Janicke et al., Air pollution co-benefits from strengthening electric transmission and distribution systems, 269 Energy 1, at 7, Figure 4 (2023), https://www.sciencedirect.com/science/article/pii/S0360544223001299?ref=pdf_download&fr=RR-2&rr=858a059008bf3b18 (attached). Six NERC regions were evaluated in the study: ReliabilityFirst Corporation ("RFC"), Western Electricity Coordinating Council ("WECC"), Midwest Reliability Organization ("MRO"), Northeast Power Coordinating Council ("NPCC"), and Southeastern Electric Reliability Council ("SERC"); certain data from the Southwest Power Pool and from power plants "not clearly defined to be in one reliability region" were omitted. *Id.* at 3.

[156] Calculated using EPA's Greenhouse Gas Equivalences Calculator by inputting 24,000,000 metric tons (equivalent to 24 megatonnes) CO_2e.

[157] Energy Innovation, Smart Design of 45V at 24.

[158] *Id.*

[159] *Id.* at 26.

[160] *Id.* at 32.

B. Treasury Should Require Site-Specific Measurements to Verify Any Claims Regarding the Emissions Rates of Polluting Electricity Generation Facilities.

1. Using EACs to track generation from "minimal-emitting" generation facilities would undermine the integrity of a tool EPA only recommended for tracking "zero-emitting electricity."

EPA advises that EACs are "an appropriate way for Treasury to document zero-emitting electricity inputs to hydrogen production for the purpose of IRC section 45V."[161] As EPA explains, Section 45V incorporates a statutory definition of "lifecycle greenhouse-gas emissions" that requires the agency to aggregate both direct emissions and significant indirect emissions.[162] EPA uses the term "zero-emitting" to refer to electricity that has zero direct GHG emissions and notes that "[f]or non-zero greenhouse-gas-emitting electricity generation, in particular, it is necessary to address any additional direct and indirect greenhouse-gas emissions, in addition to induced grid emissions, in order to consider the full range of relevant emissions pursuant to" the statutory definition.[163] Thus, the statute requires Treasury's lifecycle analysis to include the direct and indirect GHG emissions from using non-zero-emitting electricity generation. The statute does not permit Treasury to ignore the direct and indirect emissions of fossil fuel generation facilities with CCS by sweeping it into a category for facilities with "minimal" emissions.

Treasury acknowledges that EACs may not be an adequate tool for verifying the "full range of direct and indirect emissions" of electrolytic hydrogen produced from so-called "minimal-emitting sources of electricity."[164] Treasury does not define the term "minimal-emitting," but appears to consider both fossil fuel- and biomass-powered generation with CCS as possibly falling in this category.[165] Unlike the "relatively straightforward" process for verifying emissions from zero-emitting facilities through EACs,[166] the emissions intensity of fossil fuel- and biomass- powered electricity is determined by a diverse and complex set of variables. Treasury correctly identifies this issue in its Proposed Rule, noting the importance of determining the "origin of the feedstock, rate of carbon capture, and other parameters that are relevant to accurate lifecycle analysis" of "minimal-emitting sources."[167] As discussed below, ignoring these factors would lead Treasury to grant 45V tax credits for hydrogen production that is too emissions-intensive to meet the statutory requirements.

Treasury requests comment on whether EACs can "represent accurately" the many factors that contribute to the real-world emissions from producing hydrogen with fossil fuel-

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[161] EPA 45V Letter at 5.
[162] *Id.* at 1.
[163] *Id.* at 2, note 3.
[164] 88 Fed. Reg. at 89,229 ("If a hydrogen producer purchases zero GHG-emitting electricity that is represented by such EACs it is relatively straightforward to verify both the direct and indirect emissions resulting from such purchase and use. However, for minimal-emitting sources of electricity, additional considerations may be necessary to verify the full range of direct and indirect emissions.").
[165] *Id.*
[166] *Id.*
[167] *Id.*

powered generation.[168] Neither EPA nor DOE indicate that EACs do—or even can—account for those many variables.[169] To the extent EACs might be useful in tracking energy from carbon-emitting generation facilities (with or without CCS), they must fully account for an individual generating facility's direct and indirect GHG emissions. Otherwise, Treasury is likely to improperly grant 45V tax credits for hydrogen production that does not the meet statutory emissions thresholds.

2. Fossil-fueled generators with demonstrated CCS technologies are not "minimal-emitting" because electrolytic hydrogen production relying on these facilities would be too emissions-intensive to qualify for 45V credits.

Fossil fuel electricity generation with CCS should not be considered "minimal-emitting" unless it is supported by rigorous carbon accounting. The terms "minimal-emitting electricity generation" and "low-GHG generators" are consistently used in Treasury's Proposed Rule and DOE's associated technical paper[170] without being defined. Data demonstrates why emissions from fossil fuel electricity generation plus CCS should not be assumed to be insignificant.

Fossil fuel electricity generation without CCS is so highly emitting that electrolytic hydrogen powered with less than 3% fossil fueled electricity will be ineligible for 45V tax credits. According to DOE's National Renewable Energy Laboratory,[171] DOE's National Energy Technology Laboratory, [172] and DOE's Argonne National Laboratory ("ANL"),[173] coal-powered electricity has an average lifecycle GHG emissions rate of approximately 1,000 kg CO_2e/MWh and natural gas combined cycle ("NGCC")-powered electricity has one of about 500 kg CO_2e/MWh.[174] If an electrolyzer with an efficiency of 50 kWh/kg H_2[175] is powered exclusively by electricity from one of these sources, the lifecycle emissions intensities of the resulting

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[168] *Id.* at 89,299.

[169] DOE, Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit, at 10 (https://www.energy.gov/sites/default/files/2023-12/Assessing_Lifecycle_Greenhouse_Gas_Emissions_Associated_with_Electricity_Use_for_the_Section_45V_Clean_Hydrogen_Production_Tax_Credit.pdf) (going only so far as to explain how EACs could reasonably be used to demonstrate different sources' compliance with the three pillars for purposes of determining induced grid emissions).

[170] DOE, Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit (Dec 21, 2023), https://www.energy.gov/sites/default/files/2023-12/Assessing_Lifecycle_Greenhouse_Gas_Emissions_Associated_with_Electricity_Use_for_the_Section_45V_Clean_Hydrogen_Production_Tax_Credit.pdf.

[171] Nat'l Renewable Energy Lab'y, Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update, at 2 (September 2021), https://www.nrel.gov/docs/fy21osti/80580.pdf (attached).

[172] A. Cutshaw, Life Cycle Analysis of Fossil Fuel Power Generation With Carbon Capture: NGCC, SC PC, and Sub PC, DOE & Nat'l Energy Tech. Lab'y ("NETL"), at PDF p. 10, 14 (Sept. 27, 2023), https://www.osti.gov/biblio/2059617 (attached).

[173] Z. Lu & J. C. Kelly, Life-Cycle Analysis (LCA) with the GREET® Model: Electricity & Battery Electric Vehicles, ANL, at PDF p. 12 (Nov. 7, 2022), https://greet.anl.gov/files/workshop_2022_ele_bev (attached).

[174] These estimates are based on a 100-year Global Warming Potential ("GWP"), which is also currently the GWP used in the GREET model.

[175] This represents an optimistic efficiency of a future electrolyzer, *see* DOE, Technical Targets for Proton Exchange Membrane Electrolysis, https://www.energy.gov/eere/fuelcells/technical-targets-proton-exchange-membrane-electrolysis. Using this estimate helps simplify the arithmetic presented in this section.

hydrogen would be 50 kg CO_2e/kg H_2 for coal and 25 kg CO_2e/kg H_2 for NGCC. Other analyses have demonstrated how meeting the 0.45 kg CO_2e/kg H_2 threshold via electrolysis requires using at least 97% completely carbon-free electricity (where even 1–3% of fossil generation is enough to surpass this stringent standard).[176]

Even with the most generous assumptions about capture rates and methane leakage, CCS does not reduce enough of the lifecycle carbon emissions of coal or NGCC power generation to meaningfully change this calculus. The same studies (cited above) that establish lifecycle emissions of coal and NGCC electricity without CCS also estimate those emissions with the addition of CCS. Assuming a 90% capture rate, DOE laboratories estimate that the addition of CCS reduces lifecycle emissions to just over 250 kg CO_2e/MWh for coal electricity (a 75% reduction) and to just over 150 kg CO_2e/MWh for NGCC electricity (a 70% reduction).[177] Assuming 97% (NGCC) and 99% (coal) carbon capture rates, the DOE laboratories estimated coal and NGCC facilities would still have lifecycle emissions over 130 kg CO_2e/MWh.[178] Even with these higher assumed capture rates, an electrolyzer with an efficiency of 50 kWh/kg H_2 powered exclusively by coal or NGCC plus CCS electricity would have lifecycle emissions over 6.5 kg CO_2e/kg H_2 (130 kg CO_2e/MWh * 0.050 MWh/kg H_2)[179]—substantially above the least stringent emissions threshold to qualify for the 45V tax credit. Treating these generation types as "minimal-emitting" would be unsupported.

Further, it would be inappropriate for Treasury to assume that a facility with CCS will have de minimis emissions because industry has not come close to sustaining high capture rates in practice.[180] One key reason that facilities with CCS rarely capture high percentages of on-site emissions is that they do not capture emissions from all sources in the system that generates fossil-fueled electricity with CCS. For example, at the Petra Nova facility, an auxiliary natural

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[176] D. Esposito et al., Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry, Energy Innovation, at 2 (April 2023), https://energyinnovation.org/wp-content/uploads/2023/04/Smart-Design-Of-45V-Hydrogen-Production-Tax-Credit-Will-Reduce-Emissions-And-Grow-The-Industry.pdf.

[177] A. Cutshaw, Life Cycle Analysis of Fossil Fuel Power Generation With Carbon Capture: NGCC, SC PC, and Sub PC, DOE & NETL, at PDF p. 10, 14 (Sept. 27, 2023), https://www.osti.gov/biblio/2059617 (attached); Z. Lu & J. C. Kelly, Life-Cycle Analysis (LCA) with the GREET® Model: Electricity & Battery Electric Vehicles, ANL, at PDF p. 12 (Nov. 7, 2022), https://greet.anl.gov/files/workshop_2022_ele_bev (attached). Note: All of the lifecycle intensities presented thus far are based on a 100-year GWP, but the NETL report also presents values based on a 20-year GWP, which causes coal with CCS emissions to increase to over 400 kg CO_2e/MWh and NGCC with CCS emissions to increase to 250 kg CO_2e/MWh.

[178] A. Cutshaw, Life Cycle Analysis of Fossil Fuel Power Generation With Carbon Capture: NGCC, SC PC, and Sub PC, DOE & NETL, at PDF p. 10, 14 (Sept. 27, 2023), https://www.osti.gov/biblio/2059617 (attached).

[179] In 45VH2-GREET, when a user models a 50 kWh/kg H_2 electrolyzer fueled only by NGCC with CCS at 97% capture, the calculated emissions intensity is 5.2 CO_2e/kg H_2, meaning some assumptions within the background data differ from the ANL and NETL studies in this section. 5.2 CO_2e/kg H_2 still exceeds the least stringent emissions threshold to qualify for the tax credit.

[180] D. Schlissel & A. Juhn, Blue Hydrogen: Not Clean, Not Low Carbon, Not a Solution, Institute for Energy Economics and Financial Analysis ("IEEFA"), at 18 (Sept. 2023), https://ieefa.org/sites/default/files/2024-01/Blue%20Hydrogen%20Not%20Clean%20Not%20Low%20Carbon_September%202023_0.pdf (attached).

gas-fired generator was built on site to power the carbon capture equipment and this generation unit was not equipped with carbon capture.[181]

Second, industry has been unable to achieve sustained high capture rates because mechanical failures and system bottlenecks can force carbon capture systems offline for many days while a facility continues to operate, leading to uncaptured emissions. If the plant does not cease generating electricity during the time when the CCS system is offline, the carbon capture rate during this period is 0%. Industry often does not account for these upset events in estimated or reported capture rates. At the Petra Nova facility, over a three-year period, problems with the additional generator powering the carbon capture equipment accounted for 88 days of incremental outage time; problems with the carbon capture equipment itself accounted for 104 days of outages; issues with the underlying coal unit accounted for 60 days of outages; and the offtaker's inability to receive captured carbon created another 42 days of outages.[182] This variability in carbon capture at a single facility over time exemplifies why site-specific monitoring is necessary to verify emissions from a facility using CCS.

It is also unclear whether the DOE laboratories underestimate the lifecycle emissions from fossil generation facilities with CCS because they do not identify or justify their assumptions regarding upstream methane leakage rates. Most of these facilities' lifecycle emissions result from upstream methane emissions (coal mine methane for coal and methane gas leakage for NGCC). Thus, these estimates are quite sensitive to assumed methane leakage rates. The DOE laboratories would significantly underestimate the carbon intensity of electricity from fossil generators with CCS if they assumed a leakage rate of about 1%, as discussed in section V.A.

Thus, Treasury should not assume that fossil fuel generating facilities with CCS are "minimal-emitting." Even with the most generous assumptions regarding capture rates, which have yet to be realized by industry in practice, such electricity carries lifecycle GHG emissions that are incongruous with Section 45V's least stringent threshold for clean hydrogen production.

3. Electrolytic hydrogen producers that use anything other than zero-emitting electricity should be required to verify emissions claims with site-specific data.

Because data indicate that electricity from fossil fuel power plants with CCS would propel electrolytic hydrogen production well past the least stringent emissions thresholds in 45V, Treasury should **at a minimum** adopt a rebuttable presumption that the carbon intensity of such hydrogen will be too high to qualify for tax credits. That presumption should only be rebuttable through rigorous carbon accounting and site-specific emissions data. It is imperative that electrolytic hydrogen producers who use carbon-emitting power sources back up their emissions

[181] G. Kennedy, W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project (Final Technical Report), DOE & NETL, at PDF p. 7 (Mar. 31, 2020), https://doi.org/10.2172/1608572.
[182] *Id.* at PDF p. 9.

claims with rigorous, verifiable data because subsidizing hydrogen that exceeds 45V's emissions thresholds would be illegal and would have disastrous climate consequences.

Treasury rightly observes that when hydrogen producers purchase electricity from carbon-emitting sources instead of zero-emitting sources, "additional considerations may be necessary to verify the full range of direct and indirect emissions." As explained above, the statutory definition of "lifecycle greenhouse gas emissions" requires Treasury to account for both direct emissions and significant indirect emissions of electrolytic hydrogen production, which includes induced emissions from carbon-emitting electricity generation from the hydrogen producers' power supply.[183]

Treasury seeks comment on "what information is needed to document and verify GHG emissions related to" carbon-emitting power plants, including the rate of carbon capture and other relevant parameters.[184] This necessary information includes emissions data collected at both the site of the power plant and the carbon sequestration site, which would require hydrogen producers to have access to site-specific information from their carbon-emitting power source. Hydrogen producers could reasonably obtain this information by entering power purchase agreements or other contractual arrangements with a specific power provider and provide this information to Treasury accordingly.

a. Emissions data at the power plant site.

The lifecycle GHG emissions of electrolytic hydrogen produced using carbon-emitting generators include direct emissions from the power plants' smokestacks. These emissions should be verified using data from Continuous Emissions Monitoring Systems ("CEMS" or "CEM systems"), as set forth in EPA regulations at 40 C.F.R. Part 75, with two improvements: (1) the CEMS data should be correlated with long-term fuel sampling and consumption data; and (2) the continuous monitors in CEM systems also should be calibrated according to flow measurement techniques developed by the National Institute of Standards and Technology ("NIST").

Under 40 C.F.R. Part 75, CEM systems for carbon emissions generally measure both the flow rate of gas exiting a power plant's smokestack and the concentration of carbon in that gas.[185] CEMS data collected pursuant to the protocols in EPA's regulations are necessary but not sufficient to determine the carbon emissions from a carbon-emitting power plant's smokestack because that data often undercount actual carbon emissions. This is because the methodology for measuring smokestack flow—one of two key inputs for estimating carbon emissions—has been shown to permit large errors in flow estimates. NIST has observed that "[p]resently used methods to measure CO2 and other emissions from smoke stacks have errors of 20% or more depending on the level of swirl in the flow."[186] In addition, a Sierra Club review found

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[183] 26 U.S.C. § 45V; EPA 45V Letter at 1–2.
[184] 88 Fed. Reg. at 89,229.
[185] 40 C.F.R. § 75.10(a)(3).
[186] NIST, Smoke Stack Flow Measurement, https://www.nist.gov/programs-projects/smoke-stack-flow-measurement (last updated Feb. 4, 2022).

widespread underreporting of carbon emissions from coal-fired power plants linked to insufficiently stringent protocols for measuring smokestack flow.[187]

To mitigate the risk of undercounting carbon emissions from carbon-emitting power plants due to these methodological errors, the power source's CEMS data should be correlated with long-term fuel sampling and consumption data.[188] The continuous monitors in CEM systems also should be calibrated according to flow measurement techniques developed by NIST, which significantly improve the accuracy of the reference method against which continuous monitors are calibrated.[189] With these improvements, CEMS data from carbon-emitting power plants could reasonably be used to account for carbon emissions from the plants' smokestacks.

Importantly, CEMS data will account for any instances where the plant continues generating electricity while the carbon capture equipment is shut down—emissions that industry often does not account for when self-reporting carbon capture rates, as noted above.[190] Continuous data helps ensure that an accurate overall capture rate is reported for a given period.

CEMS data at smokestacks can also account for carbon emissions from the parasitic load of CCS equipment that takes power directly from the electric generating units emitting to the smokestacks. This parasitic load can increase energy requirements from a power plant by roughly 10–45% more than a plant without CCS.[191] Accounting for these emissions would be consistent with California's Low Carbon Fuel Standard ("LCFS"), which includes emissions from parasitic load in calculating annual GHG emissions from carbon capture, dehydration, and compression.[192]

Additional CEMS data will be required where the CCS equipment takes power from sources other than the electric generating unit emitting to the smokestack. For example, when carbon-emitting power plants are retrofitted with CCS equipment, separate generators or boilers are often added specifically to power that equipment. Historically, these generators have not

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[187] For a more detailed discussion of this issue, *see* Excerpt of Comments of Sierra Club et al., Re: 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, Docket ID No. EPA–HQ–OAR–2023–0072 (Aug. 8, 2023) (attached).
[188] *Id.*
[189] *Id.*
[190] The very few examples of carbon capture on fossil power plants show that such maintenance and bottleneck issues can have substantial impacts on overall carbon capture rates. *See* G. Kennedy, W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project (Final Technical Report), DOE & NETL, at PDF p. 9-10 (Mar. 31, 2020), https://doi.org/10.2172/1608572.
[191] *See, e.g.*, IPCC, Climate Change 2022: Mitigation of Climate Change, at 642 (2022), https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_FullReport.pdf (explaining that the energy penalty associated with CCS "increases the fuel requirement for electricity generation by 13–44%"); Ind. Dep't of Env't Mgmt., Wabash Valley Resources, L.L.C. Air Permit, at PDF p. 573 (Jan. 11, 2024), https://permits.air.idem.in.gov/45208f.pdf ("The parasitic load from CCS can increase energy requirements from a power plant by 10 – 40% more than a plant without CCS.").
[192] CARB, Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard, at 25 (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/2020-03/CCS_Protocol_Under_LCFS_8-13-18_ada.pdf.

been equipped with carbon capture technology.[193] The lifecycle GHG emissions of electrolytic hydrogen production that uses electricity from carbon-emitting power plants with CCS must account for emissions from the generators that power the carbon capture equipment.[194]

b. Emissions data at the sequestration site.

Lifecycle GHG emissions would also include carbon that is captured from the power plant and sequestered but inadequately contained, causing carbon to leak from subsurface storage back into the atmosphere. Multiple types of monitoring strategies are necessary to ensure long-term underground sequestration:[195]

- **Surface Monitoring**: surface monitoring starting ten years after the first injection and continuing for 50 years. Measurements should be compared to baseline monitoring established before injection begins.
- **Subsurface Monitoring of the Injection Strata**: continuous subsurface monitoring of at least the following parameters: (1) carbon mass injection rate; (2) wellhead temperature; (3) wellhead pressure; (4) bottomhole temperature; (5) bottomhole pressure; (6) annulus pressure; (7) downhole temperature with profiles at multiple locations where the injection well intersects other strata of interest such as groundwater, etc. These seven parameters, among any other relevant parameters, should be compared to the theoretical model of the subsurface that was used to identify the location as suitable for carbon sequestration. This monitoring should begin when construction of the injection well is completed. Once injection commences, this monitoring should continue indefinitely. This subsurface monitoring is one of the most critical forms of monitoring because it operates as the best "canary in the coal mine" indicator. Any substantial deviation from the baseline theoretical model is a clear indication that there is a loss of integrity of containment or likelihood of such loss. Thus, any measurements revealing deviations from the theoretical model should be carefully reviewed to ensure that the initial hypothesis of suitability is still valid or if the site needs to be abandoned since it is not suitable for sequestration.

- **Groundwater Monitoring**: continuous subsurface groundwater monitoring of all groundwater strata in the area. Monitoring wells should be located in each groundwater strata and measurements of carbon levels, pH, dissolved oxygen, and other parameters should be taken continuously to ensure that there are no leaks of carbon through the cap

[193] This is the case at the Petra Nova facility, discussed above, where an auxiliary gas-fired generator was built on-site to power the carbon capture equipment but was not itself equipped with carbon capture. G. Kennedy, W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project (Final Technical Report), DOE & NETL, at PDF p. 8 (Mar. 31, 2020), https://doi.org/10.2172/1608572. The Prairie State Generating Station in Illinois is another example. *See* K. O'Brien et al., Full-scale FEED Study for Retrofitting the Prairie State Generating Station with an 816 MWe Capture Plant using Mitsubishi Heavy Industries Post-Combustion CO2 Capture Technology (Aug. 3, 2022), https://www.osti.gov/biblio/1879443.

[194] To the extent the CCS equipment is grid-connected, induced grid emissions should also be accounted for.

[195] Treasury's implementing regulations for 26 U.S.C. §45Q should require these same monitoring strategies. *See* Public Interest Environmental Organizations Response to the Department of the Treasury on § 45Q Tax Credits for Carbon Capture, Utilization, and Storage (Dec. 2, 2022) (attached).

rock to the upper groundwater layers. This monitoring should take place as part of the initial characterization of the subsurface and should continue indefinitely after injection commences.

- **Seismic Monitoring**: seismic monitoring should be required at least once every three years after injection commences and should continue indefinitely at those time intervals. The seismic data should be used to assess how the injected carbon plume is behaving in the subsurface and how its behavior compares with the expected modeled behavior of the plume that was used to determine the suitability of the site initially.

To the extent that any such monitoring indicates that carbon is escaping from the subsurface storage site back into the atmosphere, these emissions should be accounted for in the lifecycle GHG emissions rate.[196]

Treasury also must ensure that, at minimum, the same requirements for secure geological storage outlined in Treasury's implementing regulations for Section 45Q apply to projects seeking credits through 45V, including the requirement that a taxpayer verify secure storage by "either physically or contractually" disposing of captured carbon "in secure geological storage."[197] Verifying that captured carbon is securely stored is just as important for projects seeking credits under 45V as for projects seeking credits under 45Q because carbon that leaks from storage would likely render hydrogen production projects too carbon intensive to qualify for 45V credits. It would be arbitrary for Treasury to require one process for verifying secure storage of carbon to determine 45Q eligibility and a different, weaker process to determine 45V eligibility. Treasury's final rule should also include provisions similar to those in 26 C.F.R § 1.45Q-5 for clawing back credits. Such provisions are necessary for cases in which carbon leaks change a hydrogen producer's tax credit eligibility by increasing their hydrogen's lifecycle GHG emissions.

In addition, electrolytic hydrogen producers who rely on methane-fired electricity must account for emissions associated with methane extraction, processing, storage, and delivery.[198] These emissions are discussed in section V.A.

[196] Commenters do not suggest that Treasury must account for pollution other than air emissions in determining hydrogen production's lifecycle GHG emissions rate. Rather, the non-air monitoring discussed in this section is necessary because it indicates whether carbon is leaking from a power plant's sequestration site. If the monitoring data reveals that leaks are occurring, then it likewise reveals that the power plant's once-sequestered carbon is likely being emitted back into the atmosphere. Those carbon emissions must be accounted for in the carbon intensity of the electrolytic hydrogen production that uses electricity from that power plant.

[197] 26 C.F.R. § 1.45Q-3(a); *see also id.* § 1.45Q-1(h) (stating that if a taxpayer does not "physically carry out the capture and disposal" of the carbon itself, then to qualify for tax credits, it must "contractually ensure[]in a binding written contract that the party that physically carries out the capture, disposal, injection, or utilization of the qualified carbon oxide does so in the manner" that complies with the requirements for secure geological storage in 26 C.F.R. § 1.45Q-3 among other requirements).

[198] 88 Fed. Reg. at 89,229.

IV. TREASURY MUST NOT GRANT TAX CREDITS TO HYDROGEN PRODUCERS WHO FALSELY CLAIM THAT HYDROGEN PRODUCED FROM BIOMETHANE AND FUGITIVE METHANE MEETS SECTION 45V'S EMISSIONS THRESHOLDS.

Accurate emissions accounting for fugitive methane and biomethane-based hydrogen production is vital for avoiding perverse outcomes and protecting Section 45V's ability to advance Congress' and the Biden Administration's goals for a clean hydrogen economy. We thank Treasury for requesting information that will help it evaluate and avoid these risks, such as seeking input on conditions that can be "logically consistent" with the prudent protections applied to electricity-based pathways. As Treasury notes, these conditions must "address the differences between electricity and methane."[199]

There are fundamental differences between renewable energy—derived from unlimited, naturally replenishing sources that do not emit GHG emissions—and waste methane, which is a climate super-pollutant and a finite by-product of anthropogenic resource management. A tax credit that places a price premium on methane that is purportedly a waste product introduces unique risks. First, unlike renewable energy, increased production of waste methane can increase GHG emissions beyond the current levels. Second, a price premium that is only available for waste methane used in hydrogen production will divert methane supplies away from current uses and other potential uses that would yield greater decarbonization benefits.

Treasury should address these risks, first, by carefully limiting eligibility for any favored tax treatment. Specifically, Treasury should exclude methane that is already put to productive use and methane from avoidable waste streams. Second, to accurately evaluate the carbon intensity of any eligible waste methane feedstocks under U.S. climate policies, Treasury should assume that the methane would otherwise be flared.

Another significant risk is that hydrogen producers who purchase, contract for delivery of, and use fossil fuel feedstocks will claim that they are using waste methane by purchasing credits that do not represent actual reductions in their hydrogen's lifecycle GHG emissions. Treasury should address this risk by requiring any hydrogen producer who claims to use waste methane to: (1) contract for bundled purchases of waste methane and its environmental attributes; and (2) meet meaningful deliverability requirements. Treasury should also prohibit hydrogen producers from using so-called "carbon negative" methane supplies to offset and ignore their direct emissions. These commonsense protections are also necessary to ensure the integrity of Treasury's carbon accounting for electrolytic hydrogen, as hydrogen producers could exploit the same accounting gimmicks to claim that fossil gas-fired power plants operate on waste methane.

If Treasury fails to accurately account for the lifecycle GHG emissions of hydrogen produced from methane and provides inordinate tax credits to hydrogen producers who claim to use waste methane feedstocks, the 45V tax credits may not drive innovation and investment in

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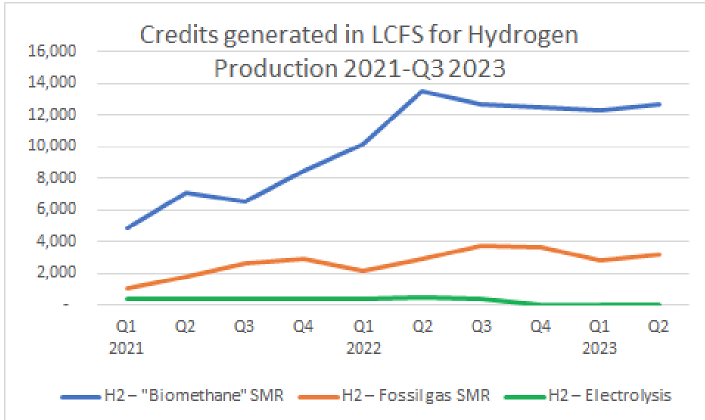
[199] *Id*. at 89,238.

truly low-carbon hydrogen production. For instance, a hydrogen producer will have no incentive to change their practices to reduce emissions if it can paper over those emissions by purchasing biogas credits. Hydrogen producers' participation in California's LCFS illustrates these risks. The California LCFS provides subsidies for hydrogen produced from fossil fuels when industry matches the fossil methane it procures with unbundled biomethane credits.[200] These subsidies are particularly lavish because the program erroneously treats biomethane from livestock manure as a carbon-negative resource. Consequently, hydrogen producers can maximize their LCFS revenue by procuring fossil feedstocks for uncontrolled SMR facilities and using paper credits to claim that their hydrogen is carbon negative. Industry takes full advantage of this arbitrage opportunity. Every single company with a certified pathway for producing hydrogen from livestock "biomethane" actually procures fossil feedstocks for California SMR facilities and buys unbundled credits from factory farms in Indiana, New York, Wisconsin, Minnesota, or Missouri.[201] The following chart shows that industry has responded to the LCFS's incentives by ramping up production of grey hydrogen and failing to produce hydrogen with the next-generation technologies that will be needed to meet the Biden Administration's climate goals.

[200] 17 CCR § 95488.8(i)(2).
[201] CARB, Current Fuel Pathways, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx (last updated Feb. 20, 2024) (showing relevant pathways by selecting "dairy manure" and "swine manure" under Feedstock and "hydrogen" under Fuel Category).

Figure 6: California LCFS credits for hydrogen, by production pathway



Data source: CARB LCFS Quarterly Data Summary for Q3, 2023.[202]

If Treasury replicates these failed policies, the 45V tax credits could become "the single greatest waste of climate money in U.S. policy history."[203] However, Treasury can avoid the blunders of the California LCFS and succeed in supporting low-carbon hydrogen production by following the requirements of Section 45V and properly accounting for hydrogen producers' direct and significant indirect GHG emissions.

A. Treasury's Rules for Biomethane and Fugitive Methane Should Be Logically Consistent with the Three Pillars.

1. Incrementality.

To ensure the 45V tax credit is only rewarding biomethane and fugitive methane capture that provides additional emissions benefits, only unavoidable, existing waste methane streams should be eligible for preferential carbon-intensity values. To avoid rewarding the use of feedstocks that provide no climate advantage over fossil methane, the following methane streams should be treated the same as fossil methane:

- <u>Methane sources in prior productive use.</u> Treasury's proposed requirement that biomethane and fugitive methane be put to its "first productive use" would properly avoid crediting hydrogen production for using methane feedstocks that provide no additional climate benefit. Treasury should implement this criterion by excluding all methane from sites with equipment for capture and productive use of methane that was already permitted on the date of the IRA's enactment. See response to Question 4, below.

[202] The source data is available for download at CARB, Low Carbon Fuel Standard Tool Quarterly Summaries, https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries.
[203] Jeff St. John, The biomethane boondoggle that could derail clean hydrogen, Canary Media (Sept. 11, 2023) (quoting carbon-offset market expert Danny Cullenward), https://www.canarymedia.com/articles/hydrogen/the-biomethane-boondoggle-that-could-derail-clean-hydrogen.

- Methane produced by current, discretionary industry practices. "Fugitive methane" from the oil and gas sector and methane from lagoon-based manure management are both examples of avoidable waste streams that exist solely because of discretionary industry decisions. Manmade methane streams are always GHG-positive. Treating this methane consistent with fossil gas is a generous approach because biomethane is more GHG intensive than fossil gas at leakage rates observed in the existing biogas industry. [204] Avoiding a price premium on methane that can be intentionally created will avoid opportunities for gamesmanship and perverse outcomes. See responses to Questions 7, 8, and 11, below.

These screens are crucial to avoid treating non-additional or counter-productive sources of biomethane and fugitive methane as an environmentally beneficial resource for hydrogen production. Treasury is correct that requirements are necessary to "reduce the risk that entities will deliberately generate additional biogas for purposes of the section 45V credit, above historic **and expected future levels**."[205] As Dr. Emily Grubert explains, "because biogas and biomethane can generate revenue, it is not only possible but expected to intervene in biological systems to increase methane production beyond what would have happened anyway when there is an incentive to do so."[206] There is a particularly acute risk that the 45V tax credit could encourage increased methane production because it is one of the most valuable energy subsidies in U.S. history.

Therefore, Treasury should ensure biomethane feedstocks provide additional emission reductions by limiting preferential carbon-intensity values to unavoidable waste methane already in existence. This approach will reward hydrogen producers for using biomethane from existing landfills that are no longer accepting organic waste or wastewater treatment plants. For unavoidable waste methane, the counterfactual baseline should be diversion from a flare, as explained in response to Question 11.

2. Geographic and Temporal Deliverability.

Robust procurement and deliverability requirements are essential for ensuring that hydrogen producers accurately account for the direct and indirect emissions from their methane use. It would be impermissible to calculate a facility's emissions under the false premise that it is using a biomethane feedstock when that facility procures fossil feedstocks because Section 45V requires Treasury to determine whether hydrogen is "produced through a process that results in a lifecycle greenhouse gas emissions rate" below statutory thresholds.[207] Purchasing unbundled biomethane environmental attributes does not affect the emissions from a facility's production process. To properly account for direct emissions from hydrogen producers that purport to use

[204] E. Grubert, At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates, 15 Env't Rsch. Letters 1 (2020) ("Grubert, At Scale") (attached), https://doi.org/10.1088/1748-9326/ab9335.
[205] 88 Fed. Reg. at 89,239 (emphasis added).
[206] Grubert, At Scale, at 5.
[207] 26 U.S.C. § 45V(b)(2).

biomethane, Treasury must require these producers to contract for bundled procurements and delivery of that biomethane.

In the electricity sector, Treasury determined that three-pillar EACs provide assurance that the emissions from the EAC-producing generator represent the emissions from the electricity used for hydrogen production.[208] Given the totally different systems for balancing supply and demand on the electric grid and the nation's methane pipelines, hydrogen producers would need to satisfy tailored criteria to demonstrate that a biomethane supplier's emissions accurately represent its methane feedstock emissions. See response to Question 9, below.

B. Treasury Should Not Allow Hydrogen Producers to Use Biomethane Purchases to Negate Emissions from Their Fossil Methane Purchases.

1. Allowing hydrogen producers to offset emissions with so-called carbon-negative biomethane would be inconsistent with the Biden Administration's goal of achieving a net-zero economy by 2050.

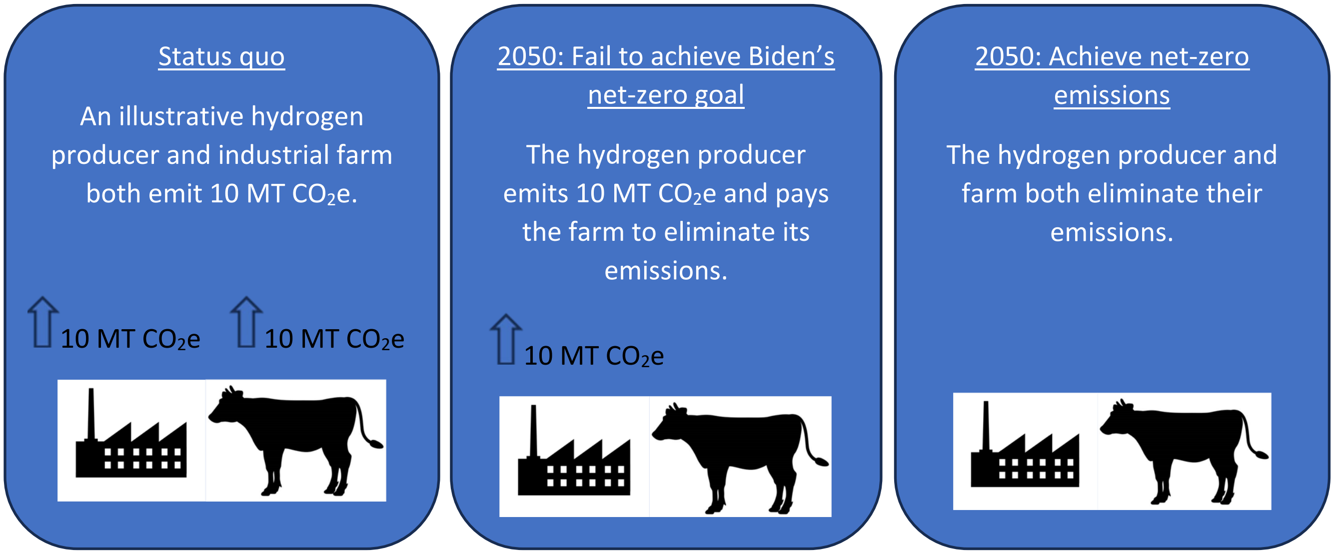
The historic investments in the Inflation Reduction Act are part of a suite of policies that prioritize "innovation, demonstration, and deployment to scale the technologies the United States needs to achieve its goals of a carbon pollution-free electricity sector by no later than 2035 and a net-zero emissions economy by no later than 2050."[209] Treasury would undermine the Biden Administration's pursuit of a net-zero emissions economy if it allowed hydrogen producers to use paper accounting practices to characterize their hydrogen as low- or zero-carbon while continuing real-world practices that emit carbon pollution.

To align with the Biden Administration's net-zero goal, Treasury should avoid the carbon accounting errors in the following example. Consider a grey hydrogen producer that uses fossil methane feedstocks and produces hydrogen with a carbon intensity of about 10 kg CO_2e/kg H_2. This hydrogen producer may claim it can bring the carbon intensity of its hydrogen down to zero by switching to a blend of carbon-emitting fossil feedstocks and carbon-negative biomethane feedstocks, without taking any other action to reduce its emissions. One recent analysis found that "a fossil hydrogen project without carbon capture could qualify for the top production tax credit by offsetting just 25% of its fuel use" if Treasury permitted such a scheme.[210] In this scenario, the purchase of some biomethane would paper over the impacts from the facility's continued use of fossil methane for 75% of its needs and its other lifecycle emissions—falsely implying that it would be acceptable for these emissions to continue indefinitely. However, as

[208] *See, e.g.*, *id.* at 89,229 ("incrementality, temporal matching, and deliverability requirements are important guardrails to ensure that hydrogen producers' electricity use can be reasonably deemed to reflect the emissions associated with the specific generators from which the EACs were purchased and retired").
[209] The White House, Fact Sheet: President Biden to Catalyze Global Climate Action through the Major Economies Forum on Energy and Climate (Apr. 20, 2023), https://www.whitehouse.gov/briefing-room/statements-releases/2023/04/20/fact-sheet-president-biden-to-catalyze-global-climate-action-through-the-major-economies-forum-on-energy-and-climate/.
[210] E. Grubert and D. Cullenward, The New Hydrogen Rules Risk Opening the Door to Methane Offsets, Heatmap (Feb. 9, 2024), https://heatmap.news/climate/hydrogen-tax-credit-final-methane-offsets (attached).

illustrated by the following figures, the United States will not reach President Biden's net-zero economy-wide emissions goal if these emissions continue (provided there is no additional action to address the hydrogen producer's emissions through carbon dioxide removal projects).

Figure 7: Emissions abatement needed for President Biden's 2050 climate goal



To achieve net-zero emissions across the economy, it is not sufficient for carbon-emitting hydrogen producers to pay for emissions reductions in other economic sectors, such as methane emissions from factory farms. Instead, the Intergovernmental Panel on Climate Change ("IPCC") has recognized that carbon dioxide removal would be necessary to address any residual emissions.[211] The IPCC makes clear that carbon dioxide removal must be in addition to—not instead of—rapid emissions cuts.[212] In this context, carbon dioxide removal means "anthropogenic activities that remove CO_2 from the atmosphere and store it durably in geological, terrestrial, or ocean reservoirs, or in products."[213] Thus, reducing agricultural methane emissions is not a form of carbon dioxide removal that could counterbalance emissions from hydrogen production in a net-zero economy. An accounting framework that suggests otherwise would threaten the Biden Administration's climate goals.

In addition, it would be inappropriate to treat any source of methane as "carbon negative," even when a hydrogen producer relies solely on that biomethane supply, as explained in response to questions 7 and 11.

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[211] IPCC, Climate Change 2022: Mitigation of Climate Change Summary for Policymakers, at 36 (2022), https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_SummaryForPolicymakers.pdf.
[212] *Id.* at 24 ("All global modelled pathways that limit warming to 1.5°C (>50%) with no or limited overshoot, and those that limit warming to 2°C (>67%), involve rapid and deep and in most cases immediate GHG emission reductions in all sectors.").
[213] *Id.* at 36.

2. **When hydrogen producers use methane feedstocks from multiple sources, each methane feedstock should be in a separate production line.**

The Proposed Rule defines a clean hydrogen production "facility" as being comprised of a single production line, which includes the property that functions interdependently to produce qualified clean hydrogen:

> A single production line includes all components of property that function interdependently to produce qualified clean hydrogen. Components of property function interdependently to produce qualified clean hydrogen if the placing in service of each component is dependent upon the placing in service of each of the other components to produce qualified clean hydrogen.[214]

Under this definition, if producing qualified clean hydrogen is not dependent on a certain component, that component is not part of the single line of production. Fossil methane should not be included in the single lines of production that produce qualified clean hydrogen from biomethane feedstocks because those production processes do not depend on fossil methane. That is, fossil methane and biomethane are not interdependent components of clean hydrogen production.

In general, there are two models for how a facility could produce hydrogen from biomethane, neither of which depends on procuring fossil methane. First, a hydrogen producer could take delivery of a biomethane supply through a dedicated conveyance, such as a pipeline that connects hydrogen production equipment to methane capture equipment at a co-located landfill or a truck that transports biomethane from a more distant wastewater treatment facility. In these scenarios, the biomethane feedstock would not physically mix with a fossil methane feedstock unless the hydrogen producer deliberately blended them. Second, a hydrogen producer could take delivery of biomethane via a common carrier pipeline. In U.S. gas markets, when industrial gas users contract for delivery of methane via commercial pipelines, the gas is scheduled for delivery during a 24-hour gas day and the gas users can take the gas from the pipeline at any point during that gas day. This system gives hydrogen producers that procure biomethane and contract for its delivery via a commercial pipeline the flexibility to take that gas from the pipeline at whatever rate suits their operational needs throughout the day. Unlike the variable renewable generation technologies that support electrolytic hydrogen, there is no risk that an unforeseen weather event will suddenly affect a hydrogen producer's ability to access biomethane. Thus, hydrogen production pathways that use biomethane are not dependent on also using fossil methane because the specific features of the biomethane supply chain obviate any need to dilute biomethane feedstocks with fossil feedstocks.

C. Responses to Treasury's Questions on Biomethane and Fugitive Methane.

(1) What data sources and peer reviewed studies provide information on RNG production systems (including biogas production and reforming

[214] 88 Fed. Reg. at 89,245.

systems), markets, monitoring, reporting, and verification processes, and GHG emissions associated with these production systems and markets?

1) **Full Biomethane Supply Chain Emissions –** S. Bakkaloglu et al., Methane Emissions Along Biomethane and Biogas Supply Chains are Underestimated, 5 One Earth 724 (2022), https://doi.org/10.1016/j.oneear.2022.05.012 (attached).

   Summary: This study is one of the largest and most recent peer-reviewed studies of biogas supply chains relying on anaerobic digestion. The review compiles published studies, on-site data taken from individual emission sources and off-site measurements reported for an entire site. It examines five stages of the biomethane supply chain: (1) Feedstock collection and storage; (2) Biogas production (e.g., the conversion of feedstock to gas via anaerobic digestion. The point sources at this stage include at minimum the digester, the buffer tank, and the hygienization tank); (3) Biogas reforming (e.g., upgrading of biomethane to remove impurities through e.g., pressure swing adsorption, water or chemical scrubbers, or membranes); (4) Transmission, storage, and distribution of product gas; and (5) Storage of digestate.

   Significant Findings:

   i) Emissions from the biogas supply chain are higher than previously understood. Results suggest they are "more than two times greater than the International Energy Agency's (IEA's) estimate of CH_4 emissions from bioenergy."

   ii) Biogas supply chains exhibit "much higher CH_4 rates than the oil and natural-gas supply chain." Median methane leakage ranged from 5.1 to 5.3%, and mean methane leakage rates were 5.90–6.04%.

2) **Emissions from Biogas Plants** – C. Scheutz et al., Total Methane Emission Rates and Losses from 23 Biogas Plants, 97 Waste Mgmt. 38 (2019), https://doi.org/10.1016/j.wasman.2019.07.029 (attached).

   Summary: This study uses a tracer gas method to measure plant-integrated methane emission rates from 23 commercially operated biogas plants in Denmark (where biogas is a relatively mature technology).

   Significant Findings:

   i) Average methane loss from the plants alone (e.g., excluding upstream or downstream emissions) was 4.6%.

   ii) Methane loss tended to decrease as gas production/plant size increased.

3) **Emissions from Biogas Upgrading** – T. Kvist et al., Methane Loss from Commercially Operating Biogas Upgrading Plants, 87 Waste Mgmt. 295 (2019), https://doi.org/10.1016/j.wasman.2019.02.023 (attached).

Summary: Researchers measure methane loss from nine commercially operating biogas plants using three different common upgrading techniques (water scrubbing, amine scrubbing, and membrane separation).

Significant Findings:

i) Average methane leakage rate across all upgrading technologies was 0.81%.

ii) Highest methane losses (1.97%) were detected in the water scrubber technology—the most widely applied technology. The lowest methane losses (0.04%) were detected from amine scrubbing systems, which are newer to North America and require steady, ample waste heat (e.g., from a combined heat and power engine) for ideal operation.

iii) Regenerative thermal oxidizers can be applied to help reduce methane loss from upgrading units.

4) **Emissions from Biomass Storage** – C. Geronimo et al., Overlooked Emissions: Influence of Environmental Variables on Greenhouse Gas Generation from Woody Biomass Storage, 319 Fuel 1 (2022), https://doi.org/10.1016/j.fuel.2022.123839 (attached).

Summary: This recent study examines the under-scrutinized GHG emissions resulting from the handling and storage of biomass intended for energy production under different environmental conditions (e.g., temperature, oxygen concentration, moisture content).

Significant Findings:

i) Storage of biomass can be a net source of GHGs if more of the carbon in the material is released as methane than as CO_2.

ii) Storage methods mimicking those commonly observed for woody biomass (large pile storage) have net GHG emissions that are not negligible, as commonly assumed.

iii) While emissions vary with temperature and moisture, all conditions yield methane concentrations above ambient levels. High temperatures (60°C) yielded significantly greater total emissions.

5) **Emissions from Counterfactuals and Leak Rates for Biogas** – E. Grubert, At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates, 15 Env't Rsch. Letters 1 (2020) https://doi.org/10.1088/1748-9326/ab9335 (attached).

Summary: This analysis scrutinizes old assumptions about counterfactuals for methane used for biogas in light of the current, GHG-conscious policy context and assesses emissions impacts under different baselines and leakage rates.

Significant Findings:

i) Methane diverted from venting is extremely rare and unlikely to constitute a reasonable baseline under GHG-conscious policy contexts. Instead, the more reasonable counterfactual is diversion from a flare.

ii) Intentionally produced methane or methane diverted from a flare can have significant GHG emissions. At leakage rates observed in the biogas supply chain, biomethane can have emissions equal to or greater than fossil gas.

iii) Unavoidable waste methane diverted from the atmosphere can be climatically beneficial, but is extremely rare—making up less than 1% of current U.S. gas demand.

6) **Emissions from animal agriculture facilities with digesters** – C. Waterman & M. Armus, Friends of the Earth, Biogas or Bull****? The Deceptive Promise of Manure Biogas as a Methane Solution (2024), https://foe.org/wp-content/uploads/2024/02/Factory-Farm-Gas-Brief_final-v2.pdf (attached).

Summary: Methane reductions from manure biogas systems are insufficient to curb agricultural methane emissions in line with President Biden's commitment to the Global Methane Pledge.

Significant Findings:

i) Herd sizes at facilities with digesters grow at 24 times the overall growth rate for dairy herds in the states covered by the study. If the cattle populations at dairies with digesters continue to grow at this accelerated rate, each farm will add an average of 177 cows in the next year, producing 10 million pounds of waste.

ii) Accounting for their increase in herd size, the installation of digesters at the studied dairies only reduced methane emissions by 11% of emissions from the baseline year. This is nearly six times less than the reductions estimated in scenarios that assume constant herd sizes and the continued use of manure lagoons.

iii) Widespread reliance on dairy digesters would not reduce methane emissions in line with President Biden's commitment to the Global Methane Pledge, but alternative strategies could yield needed reductions. Assuming 500 new dairy digesters were installed by 2030 and those digesters yielded emissions reductions comparable to those in the dataset, their associated emissions reductions would account for less than a quarter of the reductions needed to reduce agricultural methane emissions by 30%. Reducing herd sizes and implementing feasible alternative manure management strategies on 1,500 large dairies could yield 55% of the reductions needed to cut agricultural methane emissions by 30% in 2030. Paying dairy farmers to reduce their herd sizes would be nearly three times more cost-effective than subsidizing anaerobic digesters.

(2) What conditions for the use of biogas and RNG would ensure that emissions accounting for purposes of the section 45V credit reflects and reduces the risk of indirect emissions effects from hydrogen production

using biogas and RNG? How can taxpayers verify that they have met these requirements?

Monitoring requirements for the biomethane supply chain. Treasury should require continuous 24-hour methane monitoring as a condition for using biogas to produce hydrogen for the Section 45V credit at major stages of the supply chain, including biogas-to-biomethane refining, biomethane to hydrogen reforming, feedstock and digestate storage, and at injection points. A large share of biomethane's supply chain emissions occur in outlier events that are difficult to capture without continuous monitoring. As one study put it, "[s]ince super-emitters are unlikely to remain constant over time, continual monitoring will be required to detect intermittent emission patterns or unpredictable leaks from the biomethane supply chain."

Worryingly, although the digestate storage stage showed the highest total methane leakage rates, super-emitters were identified at various stages of the lifecycle, indicating that the problem is not isolated to a specific point. The authors explain that:

> super-emitters have been investigated at various stages across the supply chain, including feeding systems; substrate storage; runoff ponds; pressure relief valves on the anaerobic digesters and gas holders; exhausts and aeration lines of upgrading units; ventilation of units, such as compressors or closed digestate tanks; open digestate storage; and flaring.

To measure this, ground-based remote sensing methane monitoring systems are required. While on-site measurements of various single sources of emissions from a plant are helpful for identifying and mitigating leaks, it is easy to miss individual sources and therefore underestimate total methane leakage. Researchers therefore suggest that for the purposes of emissions reporting and environmental assessment, plant-wide ground-based measurements from a short distance away (e.g., one kilometer) are important.[215] Treasury should require ground-based remote sensing monitor systems for all methane-based pathways and require them to operate on a 24-hour basis.

Accounting for downstream emissions from biomethane production waste products. The lifecycle emissions from using livestock manure methane must include emissions associated with transport and storage of any waste biomass resulting from the biomethane production process. This includes emissions resulting from hauling digestate or biochar to wherever it is reused or disposed. Emissions from storing the by-products of the biomethane production process must be accounted for, regardless of whether they are transported elsewhere or stored on-site. Recent studies highlight that digestate-storage and handling constitutes the largest source of methane emissions from the biomethane supply chain.[216] It is vital that Treasury not

[215] *See, e.g.*, C. Scheutz et al., Total methane emission rates and losses from 23 biogas plants, 97 Waste Mgmt. 38 (2019), https://www.sciencedirect.com/science/article/abs/pii/S0956053X19304842.
[216] S. Bakkaloglu et al., Methane Emissions Along Biomethane and Biogas Supply Chains are Underestimated, 5 One Earth 724 (2022), https://doi.org/10.1016/j.oneear.2022.05.012.

inadvertently omit the largest fraction of biomethane's climate impact by ignoring the downstream emissions of the biomethane's creation.

(3) How broadly available and reliable are existing electronic tracking systems for RNG certificates in book and claim systems? What developments may be required, if any, before such systems are appropriate for use with RNG certificates used to claim the Section 45V credit?

While we do not comment on the availability and reliability of tracking systems for biomethane certificates, we do note that these systems appear to serve a very limited purpose: ensuring that entities do not use the environmental attributes of the same biomethane for compliance with multiple regulatory and voluntary programs. Tracking systems do not address the most pressing issues on which Treasury has prudently invited comment, such as ensuring that biomethane is not produced for the purpose of meeting demand in a lucrative biomethane market.

(4) How should RNG or fugitive methane resulting from the first productive use of methane be defined, documented, and verified? What industry best practices or alternative methods would enable such verification to be reflected in an RNG or methane certificate or other documentation? What additional information should be included in RNG certificates to help certify compliance?

This exclusion should cover all methane from sites with capture equipment that was already permitted on the date of the IRA's enactment for the purpose of productively using the methane. For systems that do not require construction or operation permits, Treasury should exclude methane from sites with equipment for which construction began prior to enactment of the IRA. It is important to exclude all methane from these sites, even if they collect more methane in the future than they did in August 2022, to avoid rewarding the intentional production of additional methane.

(5) What are the emissions associated with different methods of transporting RNG or fugitive methane to hydrogen producers (for example, vehicular transport, pipeline)?

We note that the emissions associated with delivery of methane must be included in the lifecycle GHG emissions analysis for all hydrogen production pathways that use methane feedstocks, even if they do not use biomethane or fugitive methane. For methane delivered via pipeline, transportation-stage emissions include impacts from both compression equipment operations and methane leakage.

(6) How can the section 45V regulations reflect and mitigate indirect emissions effects from the diversion of biogas or RNG or fugitive methane from potential future productive uses? What other new uses of biogas or RNG or fugitive methane could be affected in the future if more gas from

new capture and productive use of methane from these sources is used in the hydrogen production process?

Over-subsidization of biomethane as a hydrogen feedstock could have the unintended consequence of undermining economy-wide decarbonization by diverting scarce quantities of unavoidable biomethane waste streams away from more productive use. It is estimated that the total, finite supply of unavoidable waste methane—e.g., from uncontrolled landfills and wastewater treatment plants—is less than 1% of current U.S. gas demand. Any misallocation of this scarce resource jeopardizes our ability to achieve economy-wide decarbonization, and this is particularly true of carbonaceous feedstocks required for chemicals or products.

One of the best uses of limited, sustainable biomethane is as a feedstock for methanol production. Methanol is an important and widely used chemical feedstocks, and is gaining significant interest as a fuel for applications that cannot currently be electrified due to energy density requirements.[217] Methanol has gained particular popularity as a contender for decarbonizing shipping fuel for ocean-going vessels, with shipping giant Maersk recently placing major orders for dual-fuel methanol engine vessels.[218] Compared to the other primary contender for replacing bunker fuel—ammonia—methanol has lower toxicity, less pollution (especially NO_x) when burned, and is much safer to handle.[219] Methanol also has more immediate potential as a shipping fuel because it is cheaper to handle and liquid at room temperatures, whereas ammonia must be pressurized or chilled.[220]

The main roadblock to sustainable methanol is securing a source of biogenic carbon. Today, the carbon source for the vast majority of methanol comes from coal or natural gas reforming.[221] Biogas from landfills or sewage plants are an especially promising feedstock option for methanol production, as it is one of the few concentrated sources of biogenic carbon that does not require extensive supply chains to collect disparate, low-energy density sources of biomass, and is relatively low-cost compared to captured carbon.[222] According to analysts, after conversion losses, the total energy content of biogas produced today is estimated at 1.8 to 2 exajoules ("EJ"), while the shipping sector alone will require around 13 EJ.[223] Converting this

[217] K. Narine et al., Climate smart process design for current and future methanol production, 44 J. of CO_2 Utilization 101399 (2021), https://www.sciencedirect.com/science/article/abs/pii/S2212982020310295.
[218] P. Martin, Why Shipping is Opting for Green Hydrogen-Based Methanol Over Ammonia, Despite Much Higher Fuel Costs (Jan. 3, 2024), https://www.hydrogeninsight.com/transport/why-shipping-is-opting-for-green-hydrogen-based-methanol-over-ammonia-despite-much-higher-fuel-costs/2-1-1577939.
[219] *Id.*
[220] I. Gerretsen, The Decarbonization Tradeoffs for Ammonia, Methanol and H2 (July 22, 2022), https://maritime-executive.com/editorials/the-decarbonization-tradeoffs-for-ammonia-methanol-and-h2.
[221] Riccardo Rinaldi et al., Techno-economic analysis of a biogas-to-methanol process: Study of different process configurations and conditions, 393 J. of Cleaner Prod. 136259 (2023), https://www.sciencedirect.com/science/article/abs/pii/S0959652623004171.
[222] Int'l Renewable Energy Agency ("IRENA"), Innovation Outlook: Renewable Methanol, at 14 (2021), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jan/IRENA_Innovation_Renewable_Methanol_2021.pdf.
[223] Peter Jameson et al., Biogas Can Help Global Shipping Go Green (Jan. 19. 2024), https://www.bcg.com/publications/2024/biogas-can-help-global-shipping-go-green.

limited, valuable resource into hydrogen would only exacerbate the supply constraints for high-value bio-methanol.

Even if it is not used for methanol production, it is wasteful to convert biogas into hydrogen—forfeiting energy in the form of conversion losses, only to be left with a less readily usable fuel. For instance, steam methane reformation at central facilities entails energy losses of about 28%[224] and steam methane reformation at portable facilities that may be more suited for co-location with biomethane production have energy losses of about 40%.[225] Squandering a scarce, low-carbon resource would ultimately make it harder to decarbonize chemical or material feedstocks or fuel for ocean-going vessels. Even if it is not reserved for these optimal applications, biomethane is best used on-site to displace any remaining fossil-fueled thermal energy demand at the facility that generated the gas in the first place. Besides lowering the risks of indirect effects, co-locating biomethane production and use has the significant advantage of avoiding methane leakage caused by longer chains of transportation and distribution. Thus, diverting biomethane to hydrogen production threatens to indirectly increase greenhouse gas emissions.

Given that demand from more productive end uses can easily outstrip the finite and very limited available supply of waste methane, the only guaranteed way for Treasury to avoid indirect emissions from diversion to the inferior use of hydrogen production would be to exclude these feedstocks altogether. At a minimum, however, Treasury can reduce this risk by not assigning preferential emissions values to biomethane feedstocks that are preventable and/or already in another productive use. The use of appropriate counterfactuals for the remaining unavoidable waste methane streams will also help avoid an over-subsidization of methane as a hydrogen feedstock. See response to Question 11, below.

(7) How can the potential for the generation of additional emissions from the production of additional waste, waste diversion from lower-emitting disposal methods, and changes in waste management practices be limited through emissions accounting or rules for biogas and RNG use established for purposes of the section 45V credit?

Treasury should exercise extreme caution against this perverse outcome by establishing conservative baseline counterfactual scenarios. Controlling and avoiding methane from waste and agriculture is an important problem, but trying to use hydrogen production subsidies to solve

[224] CARB, CA-GREET3.0 Lookup Table Pathways Technical Support Documentation, at 38 (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut-doc.pdf (estimating a 72% production efficiency from central SMR hydrogen production).

[225] N.M. Pub. Regul. Comm'n, Testimony and Exhibits of Dylan Sullivan on Behalf of Coalition for Clean Affordable Energy Supporting Unopposed Stipulation, Case No. 21-00267-UT, at A-3 (May 31, 2022) (supporting a settlement that removed ratepayer funding for a proposed utility project to inject hydrogen produced via BayoTech's portable steam methane reformation technology in a gas pipeline, explaining: "carbon dioxide emissions from grey hydrogen would be around 40 percent higher than they would have been had we just used methane directly, for each unit of heat provided." Mr. Sullivan emphasized that these findings mean "blending of hydrogen derived from methane without carbon capture and sequestration on gas systems is wasteful *regardless of the source of the methane itself*. Had the blended hydrogen been derived from biomethane, the hydrogen would still have higher lifecycle emissions than direct use of that biomethane, because of the conversion step").

this problem is likely to be both less effective and riskier than simply adopting policies that limit methane emissions directly. As explained above, the extreme revenue generating potential from the 45V tax credit magnifies the risk that resource management will shift to take advantage of the incentive to produce more methane. Several well-documented factors risk driving increased methane emissions, including:

- **Subsidies incentivize a shift from less to more polluting management practices.** A recent study from New York State revealed examples of farmers there changing their practices from a more sustainable baseline where they were not producing methane purely to be able to capture California subsidies. One dairy farmer in New York interviewed for the study shared: "If I don't keep the digester between 90-100 degrees, we're not going to produce gas. So, we are being paid to create methane gas and destroy it. Now wrap your head around that one. If we just did what we normally did it would not produce methane . . . it makes no sense."[226]
- **Digesters themselves increase methane formation relative to standard manure storage systems**.[227] Depending on how much methane production has been intensified and how significant fugitive emission rates are, it is possible for the leaked methane to nullify or even exceed the methane emitted under the previous management regime.[228]
- **Actual methane capture may fall well short of stated capture rates.** Recent measurements of California concentrated animal feeding operations ("CAFOs") using remote sensing found CAFOs with covered lagoons for digesters emitted substantially similar levels of methane as those without lagoon covers.[229] A recent analysis overlaying methane plume data with CAFO digesters receiving LCFS credits found that 16 operations participating in the program released massive methane plumes after installation.[230] These digesters—designed to capture and theoretically eliminate methane venting—would qualify as "super-emitters" under Carbon Mapper's definition.
- **Digester revenues reinforce the economic advantages of larger, more polluting industrial CAFO operations.** This has been corroborated by research commissioned by the Union of Concerned Scientists, analyses by the University of California ("UC"), Davis researchers, trade publications for the dairy industry, and community reviews of

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[226] M. Hanna Pierce et al., An evaluation of New York state livestock carbon offset projects in California's cap and trade program, 14 Carbon Mgmt. 1 (2023), https://www.tandfonline.com/doi/full/10.1080/17583004.2023.2211946.
[227] Inst. for Governance & Sustainable Dev., A Primer on Cutting Methane: The Best Strategy for Slowing Warming in the Decade to 2030, at 119 (Feb. 5, 2023), https://www.igsd.org/wp-content/uploads/2022/09/IGSD-Methane-Primer_2022.pdf.
[228] *See, e.g.*, H. Balde et al., Fugitive methane emissions from two agricultural biogas plants, 151 Waste Mgmt. 123 (2022), https://doi.org/10.1016/j.wasman.2022.07.033; H. Balde et al., Methane Emissions from digestate at an agricultural biogas plant, 216 Bioresource Tech. 914 (2016), https://doi.org/10.1016/j.biortech.2016.06.031.
[229] N.T. Vechi et al., Ammonia and methane emissions from dairy concentrated animal feeding operations in California, using mobile optical remote sensing, 293 Atmospheric Env't 1 (2023), https://doi.org/10.1016/j.atmosenv.2022.119448.
[230] Food & Water Watch, The Proof is in the Pluming (Jan. 30, 2024), https://storymaps.arcgis.com/stories/4b708bdc0d2d419ba34cb352ca79b6e3.

permits for herd expansions where data was not redacted.[231] Small farms or those that avoid producing methane in the first place are excluded from the tax credit, while the largest, industrialized CAFOs that have chosen to rely on manure lagoons are able to unlock extravagant new revenue streams. In California, an Assembly Oversight analysis raised alarms that the State's policies could "provide the largest 225 dairies with a subsidized competitive advantage over smaller dairies" and warns that the State "may be going down a dangerous path for smaller dairies, where these projects don't seem viable."[232]

- **At a minimum, digesters maintain emissions when they might otherwise be reduced.** Contracts for biomethane obligate facilities to maintain polluting practices when it would otherwise be economical to reduce methane creation.

The best strategies for avoiding these perverse outcomes are to limit eligibility of biomethane and fugitive methane sources to unavoidable waste streams (see response to Question 8, below) and to avoid over-subsidizing methane feedstocks by using appropriate counterfactuals (see response to Question 11, below). Specifically, Treasury can guard against additional emissions caused by diverting waste from lower-emitting disposal methods by disallowing preferential treatment for methane produced through discretionary actions, like storing manure in lagoons and negligently maintaining oil and gas infrastructure. If Treasury's baseline assumption includes emissions from operators who choose the most polluting manure management practices, the 45V credits would counterproductively reward operators for their unsustainable choices.

(8) To limit the additional production of waste, should the final regulations limit eligibility to methane sources that existed as of a certain date or waste or waste streams that were produced before a certain date, such as the date that the IRA was enacted? If so, how can that be documented or verified? How should any changes in volumes of waste and waste capacity at existing methane sources be documented and treated for purposes of the section 45V credit? How should additional capture of existing waste or waste streams be documented and treated?

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[231] *See* A. Younes & K. Fingerman, Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard, at 19 (Sept. 2021), https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf; A. Smith, The Dairy Cow Manure Goldrush, UC Davis (Feb. 2, 2022), https://asmith.ucdavis.edu/news/revisiting-value-dairy-cow-manure; M. McCully, Energy revenue could be a game changer for dairy farms (Sept. 23, 2021), https://hoards.com/article-30925-energy-revenue-could-be-a-game-changer-for-dairy-farms.html; Leadership Couns. for Just. & Accountability, A Working Paper on the CDFA Dairy Digester Research and Development Program, at 12 (Apr. 3, 2019), https://leadershipcounsel.org/wp-content/uploads/2019/04/A-Working-Paper-on-GGRF-Dairy-Digester-Program.pdf ("In 2018, Fresno County approved Maddox Dairy's application for a dairy digester permit and a permit to increase its herd size by 700 cows from 3,309 to 4,000 -- a 24% increase. Open Sky also requested a permit to increase the size of their dairy by 700 milking cows following installation of a dairy digester. Bar 20 received approval for both a methane digester and an increase in herd size of up to 10,839 milking cows and 20,616 non-milking animals on 325 acres.").

[232] Cal. Assembly Budget Comm., Subcommittee Hearing No. 3 on Resources and Transportation, at 20 (Apr. 19, 2017), https://abgt.assembly.ca.gov/sites/abgt.assembly.ca.gov/files/April%2019%20-%20Toxics%20Recycling%20Ag.pdf.

Yes, limiting eligible waste streams to methane sources that existed as of the date of enactment of the IRA is one commonsense criterion for limiting the additional production of methane. If the volume of an existing waste stream has grown since the enactment of the IRA, the additional methane should not be an eligible biomethane resource for purposes of Section 45V. However, limiting feedstocks to waste streams that existed as of a certain date is not sufficient to avoid the perverse incentive to create more methane emissions. Therefore, we explain both why such limitations are necessary and recommend additional eligibility criteria to screen avoidable methane streams.

Treasury should limit eligibility to methane volumes that existed at the time of the enactment of the IRA. The incentive and opportunity to produce additional methane from cow manure illustrates the importance of excluding new (or newly increased) methane streams. Just 32% of dairies nationwide use the manure management techniques that cause methane to form as the manure decays (i.e., manure lagoons that contain manure in the anaerobic conditions that lead to methane formation).[233] Dairies have control over their manure management practices and can shift from current practices that do not produce methane (such as daily spread or solid storage) to using manure lagoons to maximize profits. Poorly designed public programs can provide a powerful incentive to make that shift. For instance, the value of biomethane produced from a dairy cow's manure in California's Low Carbon Fuel Standard can be just as high as the value of the cow's milk, when credit prices approach the program's price cap.[234] As one industry publication has explained, payments for biomethane transform the gas from a waste product to a co-product—or even the primary product from cattle:

> The profit generated by manure and energy is a new dynamic for dairy farms. A common arrangement is for a third party to invest in the digester and form an agreement with one or more dairy farms for a supply of manure. These contracts can be for 10 to 15 years or longer and pay $80 to $100 per cow per year or more. For a 3,500-cow dairy, that means $350,000 per year or 40 cents per hundredweight based on an 80 pound per day tank average. Some farms own the digesters, taking on the risk, but reaping potentially larger rewards. If the profits are $2 to $3 per hundredweight, they could likely exceed the profit from milk. **At that point, milk has become the by-product of manure production**.[235]

Limiting the eligibility of biomethane to existing waste streams—at their pre-IRA volumes—will help avoid rewarding dairies for producing more methane through unsustainable manure management practices. Taxpayers can document that a methane waste stream existed at a dairy

[233] R. Lazenby, Considering the Role of Anaerobic Digesters in Mitigating Emissions from California's Dairies, UCLA Sch. of Law Emmett Inst. on Climate Change & the Env't, at 7–8 (Jan. 2024), https://law.ucla.edu/sites/default/files/PDFs/Publications/Emmett%20Institute/UCLA_Emmett_CA_Dairies_1%2018%2024.pdf.
[234] A. Younes & K. Fingerman, Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard, at 19 (Sept. 2021), https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf
[235] M. McCully, Energy revenue could be a game changer for dairy farms (Sept. 23, 2021), https://hoards.com/article-30925-energy-revenue-could-be-a-game-changer-for-dairy-farms.html (emphasis added).

prior to IRA enactment with evidence that: (1) a manure lagoon already existed at the dairy; and (2) the number of cattle at the dairy has not increased since enactment of the IRA.

At the same time, it is important to note that these standards are not sufficient to avoid subsidizing activities that create additional biomethane. Installing a methane digester at an existing manure lagoon can cause it to produce even more methane than it produced before passage of the IRA, as discussed in response to Question 7. It is unlikely that a CAFO will have historical data on its pre-IRA methane emissions. Consequently, conservative carbon accounting practices, such as assuming flaring as the counterfactual means of controlling the lagoon's methane emissions, are also necessary to avoid an inordinate incentive for dairy biomethane.

Appropriate eligibility criteria for landfill gas. Treasury should also exclude eligibility for sources that can avoid the creation of methane in part or in full. While many existing landfills have organics in them that will generate methane for years to come, this practice should be avoided entirely going forward by diverting organic waste from landfills to compost facilities. To avoid counterproductively incentivizing increased landfilling of organics, Treasury should limit eligibility for landfill gas to facilities that are no longer accepting organic waste and adhere to best practices for legacy gas capture and monitoring. The California Public Utilities Commission incorporated these eligibility requirements in its own biomethane procurement policy, stating that "[l]andfill gas procurement will be limited to landfill facilities that stop accepting new organic waste and implement advanced landfill gas capture automation and monitoring technology to decrease fugitive methane emissions . . . ."[236] At a minimum, Treasury could consider setting a cap for eligible methane generation for these facilities based on methane production from the previous year's baseline (or average of the previous three years) that declines by a standard factor over time to promote reduced methane generation while still allowing capture-and-use of legacy methane. This limitation would help protect against gamesmanship, such as a landfill operator recirculating leachate to accelerate methane production.

Treasury should categorically exclude "fugitive methane" from the oil and gas sector. Treasury should not allow industry to claim a low carbon intensity for any methane from the oil and gas sector by labeling it "fugitive methane." Providing subsidies for using so-called fugitive methane from the oil and gas supply chain in hydrogen production would lead to perverse outcomes and pose profound administrative challenges. An incentive that makes fugitive methane more valuable than other methane would reward oil and gas operators for letting their equipment fall into disrepair and spewing climate pollution, as these operators could sell newly captured "fugitive methane" at a high premium after fixing the avoidable leaks. Opportunities for gamesmanship would be rife because some emissions are the result of

[236] Cal. Pub. Utils. Comm'n, Decision Implementing Senate Bill 1440 Biomethane Procurement Program, Decision No. 22-02-025, at 33 (Feb. 24, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF.

purposeful methane releases, such as releases that control tank and pipeline pressures.[237] It is doubtful Treasury could effectively prevent such gamesmanship.

Treating some methane from the oil and gas sector as low-carbon "fugitive methane" is a policy that would be uniquely difficult to administer. It is unclear how Treasury could reliably identify additional methane capture that would happen at oil and gas facilities that would not otherwise occur under multiple state and federal regulations that address methane waste in this sector. Similarly, it is unclear how Treasury could identify additional methane capture that would not occur due to the already-existing economic opportunity to capture methane for sale. Moreover, it is likely impossible to reasonably identify quantities of avoided fugitive methane from oil and gas facilities because such methane would often not be collected in separate supply streams. Rather, these facilities generally reduce methane emissions by fixing or avoiding leaks and, consequently, the purportedly captured "fugitive methane" is indistinguishable from the rest of the methane supply with which it remains comingled.

(9) Are geographic or temporal deliverability requirements needed to reflect and reduce the risk of indirect emissions effects from biogas and RNG or fugitive methane use in the hydrogen production process? If so, what should these requirements be and are electronic tracking systems able to capture these details?

To fulfill the legal requirement that hydrogen's lifecycle GHG emissions include emissions "related to" a hydrogen producer's use of methane feedstocks, Treasury must account for the emissions from the feedstocks that hydrogen producers procure and contract for delivery of. Under Section 45V, "lifecycle greenhouse gas emissions" means an aggregation of the direct and significant indirect emissions "related to" the fuel's lifecycle, "including all stages of fuel and feedstock production and distribution."[238] Consequently, the calculation of lifecycle GHG emissions for any hydrogen producer that uses methane feedstocks must include the direct and significant indirect emissions from that feedstock, starting with "feedstock generation or extraction."[239] This statutory definition does not allow industry to substitute the emissions related to its methane feedstocks with the emissions related to some other methane source (e.g., low-carbon biomethane) by engaging in a paper exercise that has no bearing on its direct emissions. Section 45V grants tax credits for hydrogen "produced through a process that results in a lifecycle greenhouse gas emissions rate" below statutory thresholds, further confirming that Treasury must evaluate lifecycle emissions rates based on a facility's actual production process—not the purchase of unbundled environmental attributes that function as offset credits.[240]

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[237] R. W. Howarth, Methane Emissions from the Production and Use of Natural Gas, The Mag. for Env't Managers at PDF p. 4–5 (Dec. 2022) ("Howarth, Methane Emissions from the Production and Use of Natural Gas"), https://www.research.howarthlab.org/documents/Howarth2022_EM_Magazine_methane.pdf (attached).
[238] 42 U.S.C. § 7545(o)(1) (incorporated by reference by § 45V(c)(1)(a)).
[239] *Id.*
[240] 26 U.S.C. § 45V(b)(2).

To determine a hydrogen producer's lifecycle GHG emissions consistent with the statute, the relevant feedstocks to account for are those that the hydrogen producer procures and legally takes delivery of. Thus, Treasury must require hydrogen producers who purport to use biomethane to contract for bundled procurements and delivery of that biomethane. Consistent with this statutory definition, EPA's longstanding Renewable Fuel Standard ("RFS") rules require any entity seeking to generate Renewable Identification Numbers ("RINs") for biomethane as a compressed natural gas ("CNG") fuel to purchase the biomethane and meet deliverability requirements that ensure the CNG user has the legal right to take delivery of it.

Consistent with the statutory definition of "lifecycle greenhouse gas emissions," EPA has adopted commonsense deliverability requirements for biomethane in its RFS regulations, which provide one source of model language Treasury should consider in this rulemaking. In its memo to Treasury, EPA explains that these rules provide a way for fuel producers to demonstrate deliverability when they rely on a commercial pipeline to transport biomethane:

> [The RFS rules] are designed to, *inter alia*, demonstrate deliverability of renewable natural gas transported via commercial pipeline. These regulations require a contractual pathway between renewable natural-gas providers and users. They also require that a volume of renewable natural gas claimed for use to produce renewable fuel must be placed into and withdrawn from a commercial pipeline in a manner consistent with that volume actually being used by the downstream renewable fuel producer.[241]

The memo alludes to several crucial rules. First, the deliverability requirements specifically mandate that CNG and liquified natural gas ("LNG") produced from biomethane can only generate RINs if they enter "a written contract for the sale or use of a specific quantity of" that fuel.[242] That is, RIN generators must buy the fuel itself and not just its environmental attributes.

In addition to requiring the actual purchase of biogenic fuels, the RFS rules include deliverability requirements that effectively ensure RIN generators have the legal right to take delivery of those fuels. EPA requires that RIN generators enter procurement contracts for the biomethane they take from a commercial pipeline and that the biomethane is "injected into and withdrawn from the same commercial distribution system" and "withdrawn from the commercial distribution system in a manner and at a time consistent with the transport of the [biomethane] between the injection and withdrawal points."[243] Gas pipeline operators balance supply and demand on their systems by matching gas suppliers' nominations to inject gas with gas purchasers' nominations to take gas over the course of a 24-hour gas day. In this framework, contracting for a biomethane supplier to inject a certain amount of biomethane into a commercial distribution system each gas day would give a hydrogen producer the right to take daily deliveries of that amount of methane from the system. Treasury should adopt rules that are consistent with EPA's biomethane deliverability rules. Specifically, Treasury should align its approach with EPA's by requiring entities that claim to take delivery of biomethane via a

[241] *Id.* at 5–6 (citing 40 C.F.R. § 80.1426(f)(11)(ii), 40 C.F.R. § 80.125(b)(3), and RFS2 Final Rule at 14712).
[242] 40 C.F.R. § 80.1426(f)(11)(ii)(B).
[243] *Id.* at §§ 80.1426(f)(11)(ii)(B), (D)–(E).

commercial pipeline system to purchase that biomethane and take legal custody of it from the same commercial pipeline system into which it is injected.

In addition to the protections EPA describes in its memo, the rules also include the crucial requirement that "CNG or LNG produced from biogas" can only generate RINs if it "was sold for use as transportation fuel and for no other purposes."[244] This language ensures that no company can generate RINs by entering a bundled contract to purchase biogenic CNG with its environmental attributes and selling off the CNG for use in another sector. Treasury should also adopt provisions that protect against such gamesmanship.

As a general matter, it is doubtful Treasury can justify adopting deliverability rules for purposes of 45V that are less stringent than the rules EPA has adopted to implement the same statutory definition. EPA is the expert agency responsible for implementing the statutory definition of "lifecycle greenhouse gas emissions" that Section 45V incorporates by reference. EPA's biogas deliverability rules have remained unchanged since their adoption in 2010 in response to recent amendments to the Clean Air Act.

Another source of reasonable model language for implementing a deliverability requirement for biomethane is California's RPS program. These requirements exist because of a scandal that emerged in 2012, when the Legislature learned certain utilities were complying with RPS requirements with biomethane procurement schemes that did not actually reduce emissions from California's electric sector, but rather involved biomethane that was injected into pipelines that flow to the East Coast.[245] Today, biomethane is only an eligible RPS resource if it is injected "into a common carrier pipeline that physically flows within California or toward the generating facility for which the biomethane was procured under the original contract."[246] To implement this type of physical flow requirement, Treasury can rely on data from the EIA, which publishes annual data on the volumes that flow in each interstate pipeline across state lines.[247] The EIA has also synthesized this data into a map that shows that flow of the nation's interstate gas pipelines.[248] A physical flow requirement would only be one element of prudent deliverability criteria. To ensure entities claiming to use biomethane can legally take delivery of that biomethane, the CEC also requires entities to "enter into contracts for the delivery (firm or interruptible) or storage of the gas with every pipeline or gas storage site operator transporting or storing the gas from the injection point to the final delivery point."[249] The California RPS also

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[244] *Id.* at § 80.1426(f)(11)(ii)(C).
[245] Assembly Committee on Utilities and Commerce Analysis of AB 2196 (Chesbro 2012) ("Many of the actual biomethane contracts executed involve sources that inject gas into pipelines flowing Eastward, i.e., there is no possibility that either the biomethane could actually be delivered into California or that such transactions will have any impact on the supply of natural gas to California.").
[246] Cal. Pub. Util. Code § 399.12.6(b)(3)(A).
[247] EIA, Natural Gas, https://www.eia.gov/naturalgas/data.php#pipelines (providing relevant data for download in the agency's releases on U.S. state-to-state capacity).
[248] EIA, Natural Gas Market Module of the National Energy Modeling System: Model Documentation 2022, at PDF p. 3 (Aug. 2022), https://www.eia.gov/outlooks/aeo/nems/documentation/ngmm/pdf/ngmm(2022).pdf.
[249] CEC, RPS Eligibility Commission Guidebook, Ninth Edition Revised, at 9 (2017), https://efiling.energy.ca.gov/getdocument.aspx?tn=217317.

requires procurement of biomethane itself—not just unbundled environmental attributes.[250] Taken together, the requirements that pipelines physically flow toward biomethane users, that users contract for delivery of biomethane they claim to use, and that users buy the biomethane they claim to use would allow Treasury to satisfy its duty to include emissions related to a facility's feedstocks in its calculation of lifecycle GHG emissions.

Failing to account for the emissions related to the feedstocks a hydrogen producer procures would not just violate the statutory requirement to consider the direct emissions related to a fuel's feedstock—it could also ignore indirect emissions impacts. The California LCFS's practice allowing CNG suppliers to characterize their fuel as biomethane through the purchase of unbundled biogas credits illustrates the potential harms of implementing Section 45V without meaningful delivery and bundled procurement requirements for biomethane. Wisconsin dairies sell environmental attributes into the LCFS program and sell the biomethane to their utilities, which inject the biomethane into their local gas distribution systems (i.e., the pipes that flow to their customers' homes and businesses—not interstate pipelines that could flow to California).[251] These dairies had previously captured their methane and used it to generate electricity.[252] However, the dairies receive such generous compensation for selling credits into the LCFS program that they are willing to sell their biomethane to the local utility for less than the price of fossil gas.[253] Driving down the price of methane in Wisconsin threatens to induce additional gas consumption, lock in dependence on gas, and, increase GHG emissions. Treasury should protect against these indirect climate impacts in its final rule by requiring any entity that claims to use biomethane to procure that biomethane (bundled with its environmental attributes) and contract for its delivery to their hydrogen production facility.

Treasury must adopt deliverability criteria for biomethane within an appropriate framework to accurately account for direct and indirect emissions from producing hydrogen with methane feedstocks. The Proposed Rule states that hydrogen producers using biomethane or fugitive methane "would be required to acquire and retire corresponding attribute certificates through a book-and-claim system," but do not define the term "book-and-claim."[254] The term "book-and-claim" can encompass a plethora of different accounting methodologies, which may give rise to confusion. For instance, one freight industry guide to book-and-claim accounting includes systems in which companies claiming climate benefits secure low-emission fuels through a legal chain of custody and systems in which companies claim the benefits of fuels that they neither use nor own.[255] For purposes of Section 45V, defensible deliverability criteria are incompatible with some versions of book-and-claim accounting. Treasury should clarify that

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[250] Cal. Pub. Util. Code § 399.12.6(b)(3)(A).
[251] C. Hubbuch, Biogas: Wisconsin utilities partner with farmers to replace fossil gas, Wis. State J. (July 19, 2022), https://madison.com/news/local/environment/biogas-wisconsin-utilities-partner-with-farmers-to-replace-fossil-gas/article_a88d7d1f-ec1f-56ed-b5c1-d12d2cd3d814.html.
[252] *Id.*
[253] *Id.*
[254] 88 Fed. Reg. at 89,239.
[255] D. Smith & A. Lewis, Voluntary Market Based Measures Framework for Logistics Emissions Accounting and Reporting, Smart Freight Ctr., at 24 (2023), https://smart-freight-centre-media.s3.amazonaws.com/documents/SFC_MBM_FRAMEWORK_2023__27_6_23.pdf.

book-and-claim accounting is only available within the deliverability constraints that are necessary to appropriately account for the direct and indirect emissions of producing hydrogen with methane feedstocks. Specifically, it would only be permissible to use book-and-claim accounting to track the environmental attributes of biomethane that the hydrogen producer has procured and contracted for delivery of.

Treasury must prohibit the use of unbundled environmental attributes to characterize methane feedstocks as biomethane, even if it allows electrolytic hydrogen producers to purchase unbundled EACs to characterize their electricity as zero-emitting, because the gas sector lacks the features of the electric sector that could lead Treasury to conclude that unbundled three-pillar EACs are a reasonable proxy for zero-emitting electricity. The vast majority of U.S. electricity sales are transactions for a local investor-owned utility, cooperative, or public agency's mix of grid electricity.[256] For customers relying on generic grid electricity, the direct emissions from a facility's use of the power grid are determined by the marginal unit in their region that is dispatched to serve new load during the facility's hours of operation—and three-pillar EACs indicate whether an additional supply of zero-emitting electricity avoids the need for a polluting generator to ramp up to meet that load. While the electric sector's economic dispatch system might allow Treasury to identify periods when zero-emission electricity is effectively serving hydrogen producers' energy needs, there is no comparable situation in the gas market. In the United States, gas utilities never meet marginal gas demand by providing biomethane. Industrial methane users primarily procure methane through bilateral contracts and contracts with gas traders. The only reasonable way to identify the direct emissions related to this methane is by considering the emissions from the methane these users procure and contract for delivery of.

Electronic tracking systems may be useful for implementing some reasonable requirements for hydrogen producers that use biomethane. For instance, Treasury may reasonably use such a system to verify purchase of low-carbon biomethane and track environmental attributes to avoid double counting. Treasury might also use an electronic system to track when biomethane meets certain criteria that indicate it can be used for hydrogen without inducing additional emissions, such as Treasury's proposed criteria that biomethane be put to its first productive use. However, tracking systems cannot substitute for requiring hydrogen producers to purchase and contract for delivery of any biomethane they claim to use. There is no point in using an electronic system to track unbundled biomethane attributes because such attributes are irrelevant to the lifecycle GHG emissions of hydrogen producers who procure and use fossil methane feedstocks.

(10) How should variation in methane leakage across the existing natural gas pipeline system be taken into account in estimating the emissions from the transportation of RNG or fugitive methane or establishing rules for RNG or fugitive methane use? How should methane leakage rates be estimated based on factors such as the location where RNG or fugitive

[256] EIA, Electricity explained: Electricity generation, capacity, and sales in the United States, https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php (explaining that only 15% of electricity sales in 2021 were by a category of "other providers" that includes direct electricity transactions between independent power producers and electricity customers),

methane is injected and withdrawn, the distance between the locations where RNG or fugitive methane is injected and withdrawn, season of year, age of pipelines, or other factors? Are data or analysis available to support this?

Treasury should include pipeline leakage in calculating lifecycle GHG emissions of any hydrogen production pathway that relies on methane pipelines, including all pathways that use fossil methane delivered via pipeline. The pipeline leakage data that Treasury has solicited in its efforts to develop appropriate carbon accounting for biomethane and fugitive methane will be equally relevant for any hydrogen producer that takes delivery of methane via a pipeline.

(11) What counterfactual assumptions and data should be used to assess the lifecycle GHG emissions of hydrogen production pathways that rely on RNG? Is venting an appropriate counterfactual assumption for some pathways? If not, what other factors should be considered?

Venting is never an appropriate baseline for waste or biomethane. It would be unjustified to assume that industries will continue venting their methane into the atmosphere simply because they do so today. That assumption is inconsistent with the United States' commitments under the Paris Agreement and the Biden Administration's goal of economy-wide carbon-neutrality by 2050.[257] As researchers have stressed, the assumption that methane will otherwise vent into the atmosphere "is flawed if one also assumes that GHG emissions reductions are a policy priority, as existing practice is not the appropriate baseline for determining the counterfactual management practice . . . ."[258] As the study points out, "if the methane can be captured for RNG production, it can be captured for diversion to a flare, and it is unrealistic to assume that capturable methane would be vented under a GHG conscious policy regime."[259] The Biden Administration's all-of-government approach to tackling the climate crisis makes it an unmistakably GHG-conscious policy regime.[260] There is no realistic scenario where the United States can allow controllable, fugitive methane to persist indefinitely and meet its Nationally Determined Commitments under the Paris Agreement or the Biden Administration's unequivocal

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[257] Nat'l Academies of Scis., Eng'g, and Med., Accelerating Decarbonization of the U.S. Energy System (2021), at 80 https://doi.org/10.17226/25932. ("In line with the IPCC Special Report on 1.5°C, this report assumes that methane emissions can be reduced by 65 percent below 2010 levels by 2050.").

[258] Grubert, At Scale at 5.

[259] *Id.*

[260] At the most recent United Nations Conference of the Parties in 2023, the United States convened several nations in joining the Global Methane Pledge with a goal of "cutting anthropogenic methane emissions at least 30% by 2030 from 2020 levels." U.S. Dep't of State, Highlights from 2023 Global Methane Pledge Ministerial (Dec. 4, 2023), https://www.state.gov/highlights-from-2023-global-methane-pledge-ministerial/#:~:text=The%20leaders%20of%20Canada%2C%20the,TEAP)%20released%20its%20first%20report. The White House paired the pledge with the release of the "U.S. Methane Emissions Reduction Action Plan," the product of an inter-agency Methane Task Force "working to advance a whole-of-government approach" to proactive methane detection and enforcement of methane regulations to reduce emissions. The White House, Accelerating Progress: Delivering on the U.S. Methane Emissions Reduction Action Plan, at 1–2 (Dec. 2023), https://www.whitehouse.gov/wp-content/uploads/2023/12/Methane-Action-Plan-2023-Topper.pdf.

commitments on methane reduction. Therefore, Treasury must assume capturable methane streams are controlled under the reference case.

Accordingly, we recommend Treasury screen waste or biomethane into two categories to determine appropriate baseline counterfactuals: **Discretionary waste methane** and **unavoidable waste methane.**

The first category of Discretionary Waste Methane includes any waste methane that results from management practices where alternative management strategies that avoid methane are reasonably available. There is broad consensus, including from EPA's waste hierarchy, that waste prevention is the most preferred management approach.[261] For many current sources of waste methane, prevention is both the optimal practice and viable to implement. For example, livestock management practices can keep manure out of lagoons by transitioning toward dry scrape or aeration practices that prevent significant waste methane generation in the first instance.[262] Similarly, landfills can avoid the creation of additional methane by no longer accepting new organic waste and avoiding additional methane creation through composting or recycling.[263] Because of methane's extreme radiative force, the high methane leakage rates observed in the biomethane supply chain, and the perverse incentives of rewarding poor resource management, it is always preferable to avoid the creation of methane in the first instance. Accordingly, Treasury should assign that waste or biomethane an emissions value consistent with conventional fossil gas. As research shows, at leakage rates between 5–6.6% (consistent with observed leakage rates in the biomethane supply chain[264]), biomethane from intentionally produced methane can be **more** GHG intensive than fossil gas.[265]

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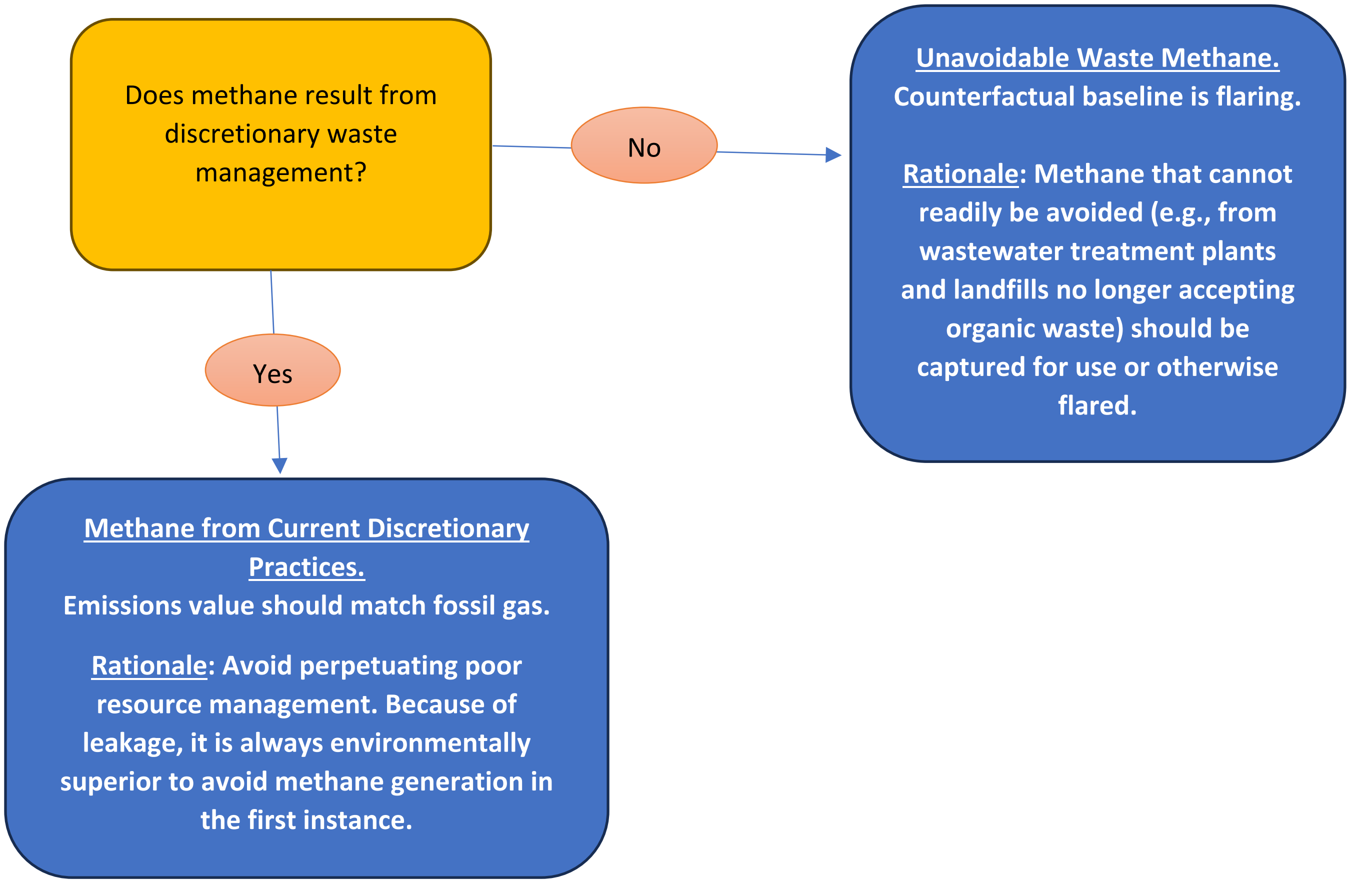
[261] EPA, Sustainable Materials Management: Non-Hazardous Materials and Waste Management Hierarchy, https://www.epa.gov/smm/sustainable-materials-management-non-hazardous-materials-and-waste-management-hierarchy (last updated Feb. 21, 2024).
[262] *See, e.g*., California Department of Food and Agriculture, Alternative Manure Management Program (AMMP) (Accessed Feb. 21, 2024), https://www.cdfa.ca.gov/oefi/AMMP/.
[263] EPA, Composting Food Waste: Keeping a Good Thing Going (Oct. 2020), https://www.epa.gov/snep/composting-food-waste-keeping-good-thing-going.
[264] S. Bakkaloglu et al., Methane emissions along biomethane and biogas supply chains are underestimated, 5 One Earth 724, at 726 (2022), https://www.sciencedirect.com/science/article/pii/S2590332222002676.
[265] Grubert, At Scale at 4.

Figure 8: Determining Appropriate Counterfactuals for Different Methane Feedstocks



If an applicant can convincingly demonstrate to Treasury that its biomethane supply comes from a source that cannot be reduced through available management options, their methane could be considered "unavoidable waste methane" which may be environmentally beneficial to capture and use. In this case, the appropriate counterfactual would be flaring—not venting. Flaring must be treated as the minimum baseline counterfactual because any methane that can be captured for hydrogen production can also be captured and diverted to a flare. As explained by Dr. Emily Grubert, "flaring destroys the methane with the same destructive benefit as combusting the methane productively . . . [and] flaring is most likely the less GHG intensive alternative for waste methane once it has been captured."[266] Flaring is a superior climate strategy to putting methane to productive use unless net leakage of the captured methane is lower than the flare leakage. Energy recovery—specifically for hydrogen production—may still be preferable to flaring even though it is not carbon negative. For instance, models estimate that the average emissions for compressed hydrogen produced from landfill gas is about 15% lower carbon

[266] The reason, Grubert explains, is that "In a decarbonized energy system where RNG would be less likely to be replacing GHG-intensive fuels (and thus offsetting their emissions), and when a policy regime requiring or incentivizing destruction of GHG-intensive wastes might reasonably be expected to be in place, expected levels of methane leakage suggest that RNG is unlikely to be a low GHG energy resource relative to alternatives." Grubert, At Scale at 7.

intensity than compressed hydrogen made from fossil gas, even when they assume the landfill gas would otherwise be flared.[267] Consequently, 45V will still reward hydrogen producers for using unavoidable streams of waste methane for hydrogen production even if Treasury aligns GREET or its successor model with the Biden Administration's climate policies and operates under the reasonable assumption that biomethane used for hydrogen production would otherwise be flared.

D. Improper Treatment of Biomethane Threatens the Integrity of Treasury's Carbon Accounting for Electrolytic Hydrogen, as Well as Hydrogen Derived from Methane Feedstocks.

Treasury's criteria for eligible biomethane and its policies for assessing the carbon intensity of biomethane have enormous stakes not just for hydrogen producers who use methane feedstocks, but also for electrolytic hydrogen. Gas-fired electricity generators are likely to exploit any offsetting loopholes or unjustifiably low carbon-intensity values for biomethane. For example, due to the flawed assumption in California's LCFS that livestock biomethane is a "carbon negative" resource, CARB routinely certifies pathways with carbon intensity scores less than -500 gCO_2e/MJ for electricity from reciprocating engines that burn dairy biomethane.[268] If Treasury fails to learn lessons from the California LCFS and treats biomethane as carbon negative, it would open the door to abuses like hydrogen producers claiming that the use of biomethane-fueled electricity negates the pollution from using emissions-intensive grid power. The numbers are staggering. A hydrogen producer might claim to produce zero-carbon hydrogen by using 80 MWh of California grid-average electricity (with a carbon intensity of 93.75 gCO_2e/MJ) and 10 MWh of biomethane-fueled electricity (with a carbon intensity of -756.17 gCO_2e/MJ).[269] This loophole could erase the incentive to invest in truly clean and innovative hydrogen production technologies.

One electrolytic hydrogen project in California exemplifies how these perverse incentives are driving companies to produce hydrogen from gas-fired power. H2B2 is developing an electrolytic hydrogen production facility where it can generate more LCFS credits by using biomethane-fired electricity than solar.[270] Relying on biomethane is a more lucrative source of subsidies, even though it is cheaper for H2B2 to produce hydrogen with biomethane-fired generators than solar.[271] The 45V credits could inadvertently devastate the market for renewable

[267] CARB, CA-GREET 3.0 Lookup Table Pathways: Technical Support Documentation (Aug.13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut-doc.pdf.
[268] CARB, Current Fuel Pathways, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx (last updated Feb. 20, 2024) (showing relevant pathways by selecting "Electricity" under Fuel Type and "Dairy Manure" under Feedstock).
[269] A recent typical pathway for electricity as a transportation fuel produced from dairy manure biogas using a reciprocating engine in Madera, CA (application B038201) has a certified carbon intensity of -756.17 gCO_2e/MJ. *Id.* According to CARB's look-up table, California grid-average electricity has a carbon intensity of 93.75 gCO_2e/MJ. Cal. Code Regs. tit. 17 § 95488.5(e), Table 7-1.
[270] E. Penrod, Biogas more cost-effective than solar to power new green hydrogen facility: H2B2, UtilityDive (Nov. 16, 2023), https://www.utilitydive.com/news/h2b2-green-hydrogen-california-solar-biogas/699963/.
[271] *Id.*

electrolytic hydrogen if facilities could claim to run on zero- or negative-carbon biomethane when they rely on fossil methane-fired generators paired with biomethane credits.

E. The Final Rule Should Refer to Biomethane as "Biomethane" and Refrain from Using the Misleading Term "Renewable Natural Gas."

The Proposed Rule misleadingly uses the term "renewable natural gas" or "RNG" to refer to "biogas that has been upgraded to be equivalent in nature to fossil natural gas."[272] The term "renewable natural gas" was invented by a public relations firm hired by the fossil fuel industry.[273] This term does not appear in the IRA, nor in any other federal statute.[274] Referring to biomethane as a "renewable" resource tends to mislead the public by falsely implying that it is "easily replaced."[275] In reality, biomethane is scarce and its supplies are often depleted upon use, such as biomethane from landfill biogas.[276] Moreover, calling biomethane "renewable" may create the false impression that it is environmentally benign, when any intentionally produced methane will increase GHG pollution (unless total system leakage is zero)[277] and the practices that create biomethane can harm local communities.[278] Therefore, the final rule should use the neutral and accurate term "biomethane" to refer to this resource.

V. TREASURY MUST ACCURATELY ACCOUNT FOR THE EMISSIONS INTENSITY OF FOSSIL HYDROGEN.

A. The Methane Leakage Rate in 45VH2-GREET Must Be Updated to Align with Peer-Reviewed Research.

The statutory definition of lifecycle GHG emissions includes direct and significant indirect emissions related to a fuel's full lifecycle, including "all stages of fuel and feedstock production and distribution," starting with the "feedstock generation or extraction."[279] For hydrogen produced from fossil methane feedstocks, the most significant source of emissions related to feedstock production and distribution is the fugitive methane pollution that occurs at each stage of the gas supply chain, from extraction, to processing, storage, and delivery.[280] In determining fossil hydrogen's lifecycle greenhouse gas emissions, Treasury must include values

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[272] 88 Fed. Reg. at 89,238.
[273] S. Meredith, PR firms are facing a backlash for 'greenwashing' Big Oil—and the pressure on them is growing, CNBC (Feb. 16, 2022), https://www.cnbc.com/2022/02/16/big-oil-and-the-climate-crisis-the-fight-to-hold-pr-firms-accountable.html.
[274] *Cf.* 42 U.S.C. § 16292(a)(2)(E) (providing that the constituents of natural gas can include "biomethane").
[275] Renewable, Cambridge Dictionary, https://dictionary.cambridge.org/us/dictionary/english/renewable.
[276] Sasan Saadat et al, Rhetoric vs. Reality: The Myth of "Renewable Natural Gas" for Building Decarbonization, at 11–12 (July 2020) ("Saadat, Rhetoric vs. Reality"), https://earthjustice.org/wp-content/uploads/report_building-decarbonization-2020.pdf.
[277] Grubert, At Scale at 6.
[278] Saadat, Rhetoric vs. Reality at 8.
[279] 42 U.S.C. § 7545(o)(1) (incorporated by reference by § 45V(c)(1)(a)).
[280] *See, e.g.*, Howarth & Jacobson at 1679.

for these upstream methane leaks that reflect sound science and not injudicious reliance on industry-provided data.

Updating 45VH2-GREET's assumptions regarding methane leakage from the gas sector is critical to the integrity of determining the lifecycle GHG emissions from hydrogen production. Currently, 45VH2-GREET assumes that only 0.9% of methane is lost to fugitive emissions upstream of a hydrogen production facility. GREET relies on self-reported industry data in EPA's GHG inventory to estimate fugitive emissions from gas production.[281] These production-stage emissions contribute about 60% of the fugitive emissions from the supply chain upstream of a hydrogen production facility according to field measurements in a 2018 study by Alvarez et al.[282] Thus, by relying on lower, industry-reported production-stage emissions, GREET dramatically underestimates overall leakage rates, even though it relies upon the Alvarez 2018 measurements for other stages of the supply chain (Gathering & Boosting, Processing, Transmission, and Distribution). Overall, Alvarez 2018 estimates that 2.3% of gross U.S. gas production is lost to fugitive emissions.[283] At a minimum, the integrity of 45VH2-GREET requires using assumptions on fugitive methane emissions that are based on measurement data provided without the cooperation of industry.[284] Incorporating peer-reviewed literature that is more recent than Alvarez's 2018 study will likely lead to an estimate of upstream methane leakage that exceeds 2.3%.[285] A 2022 review of studies synthesized the available aircraft and satellite data on gas production, storage, and transportation emissions at the regional level. It found a mean weighted upstream leakage rate of 2.6%, when weighting each study's estimates by the volume of production in the observed gas field and omitting the two highest estimates as possible outliers.[286] Treasury must update the upstream leakage assumption in the 45VH2-GREET background data to accurately account for emissions produced from methane.

Treasury has also failed to justify deviating from the assumptions in the standard GREET R&D model and assuming a leakage rate of 0.9% in 45VH2-GREET. Treasury may have

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[281] *See* A. Burnham, Updated Natural Gas Pathways in GREET 2023, at 5, Table 3, ANL (Oct. 2023), https://greet.es.anl.gov/publication-update_ng_2023.
[282] R. A. Alvarez et al., Assessment of methane emissions from the U.S. oil and gas supply chain, 361 Science 186, at 187, Table 1 (June 21, 2018) ("Alvarez 2018"), http://science.sciencemag.org/content/361/6398/186 (attached).
[283] *Id.* at 186.
[284] *Id.* at 187 (explaining that one potential bias in the EPA inventory data is that "[o]perator cooperation is required to obtain site access for emission measurements. Operators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive. The potential bias due to this 'opt-in' study design is very challenging to determine. We therefore rely primarily on site-level, downwind measurement methods with limited or no operator forewarning to construct our [bottom-up] estimate.") (footnote omitted).
[285] *See* Y. Zhang et al., Quantifying methane emissions from the largest oil-producing basin in the United States from space, 6 Science Advances 1, at 1 (2020), https://www.science.org/doi/epdf/10.1126/sciadv.aaz5120; G. Plant et al., Inefficient and unlit natural gas flares both emit large quantities of methane, 377 Science 1566, at 3 of 5, Table 1 (2022), https://www.science.org/doi/10.1126/science.abq0385; E. Murphy & J. Yu, Research shows gathering pipelines in the Permian Basin leaking 14 times more methane than officials estimate, Env't Def. Fund (Oct. 4, 2022), https://blogs.edf.org/energyexchange/2022/10/04/research-shows-gathering-pipelines-in-the-permian-basin-leaking-14-times-more-methane-than-officials-estimate/; J. Yu et al., Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin, 9 Env't Sci. & Tech. Letters 969, at 969 (Oct. 4, 2022), https://pubs.acs.org/doi/pdf/10.1021/acs.estlett.2c00380.
[286] Howarth, Methane Emissions from the Production and Use of Natural Gas at PDF p. 2.

developed a new leakage rate assumption by excluding data related to facilities whose primary purpose is oil production, as opposed to gas production. However, methane is often produced and captured as a co-product at sites primarily developed for oil production. It would be inappropriate to ignore data from facilities whose primary purpose is oil production because some methane used as a hydrogen feedstock is likely to come from facilities that co-produce oil and methane. Indeed, excluding an emissions-intensive source of methane in the hydrogen producers' supply chain would violate the statutory requirement to aggregate all emissions from feedstock production and distribution.

B. Failing to Account for the 20-Year Global Warming Potential of GHG Emissions Improperly Underestimates Impacts.

Treasury should consider hydrogen producers' lifecycle GHG emissions over both 20-year and 100-year periods. As the most recent report of the IPCC has observed, "widespread adverse impacts" from climate change have already begun to occur.[287] As we face the urgency of climate change, considering the warming impacts not only over a 100-year timeline but also over a 20-year timeline is necessary to minimize climate-related harm. Methane breaks down more quickly in the atmosphere than CO_2 and, therefore, methane's warming impacts are more concentrated in the first 20 years after it is released. Methane has about 30 times the warming impact of CO_2 over a 100-year period and more than 80 times the warming impact of CO_2 over a 20-year period.[288] Consequently, the choice of a GWP period has a substantial impact on lifecycle emissions estimates. Given the urgency of the climate crisis and the relevance of methane emissions in 45VH2-GREET, Treasury should update the model to display lifecycle emissions intensity based on both 20-year and 100-year GWPs and only award 45V tax credits to hydrogen producers who meet statutory carbon-intensity thresholds on both timescales. At a minimum, Treasury should require hydrogen producers to report their lifecycle GHG emissions on both 20-year and 100-year timescales.

C. Co-Product Accounting in 45VH2-GREET Should Not Allow for Emissions Reductions from Carbon Capture and Utilization Products.

Treasury's approach to accounting for carbon capture and utilization ("CCU") co-products should be consistent with the current best practices for avoiding double-counting of emission reductions. Carbon that is captured in the fossil hydrogen production process can be utilized as a feedstock for various products, which have been grouped by ANL in their applicable GREET guidance document into fuel and non-fuel products.[289] Fuel products are ultimately burned, and the captured carbon is thus released into the atmosphere. For non-fuel products, such

[287] IPCC, Climate Change 2023 Synthesis Report, Summary for Policymakers, at 5 (2023), https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_SPM.pdf (original emphasis omitted).
[288] IPCC, Climate Change 2021, The Physical Science Basis, at 1017 (2021), https://report.ipcc.ch/ar6/wg1/IPCC_AR6_WGI_FullReport.pdf.
[289] K. Lee et al., Accounting for CO2 Sources in Analyzing the Life Cycle CO2 Emissions of Carbon Capture and Utilization for Fuels and Products in the GREET Model, ANL (November 1, 2022), https://greet.anl.gov/publication-ccu2022 (attached).

as green cement, the carbon is "stored" long term in the product. ANL's guidance explicitly states that "emission reductions from CCU technologies should be solely assigned to CCU fuels or products. To avoid double counting, the original facilities (with their original products) should not be allowed to claim CCU-resulted emission reductions."[290] Such emissions reductions result from the fact that carbon is used as a feedstock rather than emitted into the atmosphere by the original facility. There is a net reduction for non-fuel products so long as the emissions associated with capturing, compressing, transporting, and processing the captured carbon do not outweigh the emissions that were captured in the first place.

ANL's approach is appropriate. Both the emissions reductions and the positive emissions associated with the capture, compression, and transport of carbon should be solely attributed to the CCU product. It is reasonable for the entity that productively uses the carbon to take credit for those reductions because only the end user can guarantee how much carbon was ultimately "stored" in their CCU product. It would be far more difficult to administer a regime in which the entity that captures the carbon takes credit for these reductions because they lack visibility over how much carbon the end user vents. It is essential that only one entity take credit for the emissions reductions associated with the use of captured carbon. If Treasury fails to adhere to ANL's standardized practices for attributing emissions reductions to CCU products, it will create an unnecessary and significant risk of double-counting. Therefore, any fossil hydrogen facility that captures carbon for use in CCU products should enter information into GREET as if it does not capture carbon.

D. Properly Accounting for the Capture, Compression, Transport, and Sequestration Emissions Associated with Sequestered Carbon Requires Project-Specific Inputs and Additional Monitoring and Verification Procedures for Sequestration Sites.

Treasury properly included the emissions associated with carbon capture, compression, transport, and sequestration within the system boundary of hydrogen production when carbon is sequestered. These emissions can be substantial and must be accounted for to accurately assess the emissions intensity of fossil hydrogen production. The magnitude of emissions associated with carbon capture varies considerably depending on the design of the fossil hydrogen production facility. Many facilities that have been retrofitted to date to include carbon capture build auxiliary generators on site (from which emissions are **not** captured) to power the capture system.[291] This could be considered a worst-case scenario for the emissions intensity of carbon capture. Researchers have estimated that for fossil hydrogen facilities designed in this way, even with capture rates above 80%, lifecycle emissions will only be reduced by about 10% compared to a fossil hydrogen facility without carbon capture because of the large energy requirement of

[290] *Id.* at 3.
[291] Gloria Power et al., Demonstration of Carbon Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large-Scale Hydrogen Production, at 4 (May 5, 2018), http://www.osti.gov/servlets/purl/1437618/ (see reference to COGEN system).

carbon capture systems.[292] Treasury must continue to include these emissions within the system boundary of hydrogen production in future versions of 45VH2-GREET.

However, properly accounting for emissions from the capture, compression, transportation, and sequestration of carbon will require Treasury to adopt additional provisions. As discussed in section II.B.3.b., Treasury must ensure that the final rule includes requirements for secure geological storage that align with the requirements for claiming Section 45Q tax credits. Unless hydrogen producers verify the use of secure geological storage in the same way that taxpayers do under Section 45Q, Treasury will not have a reasonable basis for determining the hydrogen's lifecycle GHG emissions. Further, 45VH2-GREET currently contains static assumptions related to: (1) engineering of carbon capture systems (does not account for the possibility of auxiliary generators); (2) carbon transport distance; and (3) necessary boosting stations along the carbon pipeline. Just as site-specific data is necessary to determine potential leakage from sequestration sites, project-specific capture and transport information would more accurately account for emissions than the current static assumptions.

E. Incorrectly Accounting for Emissions from Fossil Hydrogen Production Will Not Only Subvert the Goal of the 45V Tax Credit but Also Spur Local Harm to Human Health and the Environment.

Treasury must take the steps outlined above to ensure scientifically accurate emissions intensities are calculated for fossil hydrogen. Failing to do so will not only subvert the Biden administration's decarbonization goals, but also cause localized harm on the environment and human health. As noted in an October 2021 letter signed by 19 members of Congress, "[t]he expansion of fossil-fuel based hydrogen would inevitably harm disproportionately low-income communities and communities of color because these are the same communities which have carried the weight of fossil fuel pollution for generations."[293] This remains true even if carbon capture equipment is used to lower the carbon intensity of the hydrogen. Underestimating the GHG emissions of fossil hydrogen will lead to subsidies for production pathways that further entrench environmental harm and human health impacts from the gas industry.

VI. TREASURY MUST PROPERLY ACCOUNT FOR HYDROGEN VENTING AND LEAKAGE AT PRODUCTION FACILITIES.

The final rule should account for a production facility's fugitive hydrogen emissions because these emissions can be significant, even at facilities that are not perpetuating the type of abuse Treasury has reasonably addressed through proposed rule § 1.45V-2(b)(1). According to one recent paper, the leakage rates at hydrogen production facilities are estimated to be up to

[292] Howarth & Jacobson at 1676.
[293] Senator J. Merkley et al., U.S. Congress, Letter to Speaker N. Pelosi and Leader C. Schumer, U.S. Congress, at 1 (Oct. 27, 2021), https://www.merkley.senate.gov/wp-content/uploads/imo/media/doc/Blue%20Hydrogen-Letter%20to%20Leadership-10-27-21.pdf.

1.5% for blue hydrogen and 0.03–9.2% for electrolytic hydrogen.[294] It would be unreasonable to ignore these emissions, when a leakage rate of 10% across the entire supply chain (including emissions at the production, transportation, storage and use stages) could negate all benefits of using renewable electrolytic hydrogen instead of fossil fuels.[295]

To properly account for these fugitive emissions in its final rule, Treasury should include two additional provisions. First, the rule should clearly state that a taxpayer's eligibility for tax credits under Section 45V is based on the number of kilograms of clean hydrogen that it sells or uses—not the amount of hydrogen that it produces. The statute's plain language only authorizes tax credits for hydrogen produced "for sale or use."[296] Treasury has recognized that it would be improper to provide tax credits for hydrogen that is purposefully wasted by proposing rule § 1.45V-2(b)(1). The same straightforward application of the statute demands that Treasury not provide tax credits for hydrogen that is incidentally wasted. Unless Treasury explicitly addresses this issue in the final rule, there is a risk that industry will seek to exploit the proposed regulatory definition of hydrogen "for sale or use"—which includes hydrogen made "for the primary purpose of" being available for sale or use.[297] That is, hydrogen producers may claim tax credits for producing hydrogen with the intent to sell it, even when the producer accidentally vented the hydrogen into the atmosphere instead of selling or using it. The plain text of Section 45V does not allow this outcome. Treasury should explicitly recognize that a hydrogen producer that produces ten tons of hydrogen, vents one ton of hydrogen, and sells nine tons of hydrogen can only claim tax credits for the nine tons of hydrogen sold.

Second, Treasury should account for the climate-forcing impacts of a facility's fugitive hydrogen emissions when it calculates the lifecycle GHG emissions of the hydrogen that the taxpayer sells. Hydrogen is an indirect GHG with a GWP that is about 11.6 times greater than CO_2 over a 100-year period.[298] Over the first 20 years, hydrogen has about 40 times the warming power of carbon dioxide.[299] A production facility's emissions of this potent climate pollutant are part of the lifecycle GHG emissions of the hydrogen it produces. The statutory definition of lifecycle GHG emissions includes direct emissions related to all stages of fuel production.[300] Accordingly, it would be unreasonable for any carbon accounting for hydrogen's lifecycle GHG emissions to ignore the climate impacts of a production facility's fugitive hydrogen emissions.

By adopting clear and reasonable policies on accounting for vented hydrogen now, Treasury will also set appropriate expectations for companies that are developing novel hydrogen production techniques with substantial leakage risks. Sound accounting practices are even more

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[294] Sofia Esquivel-Elizondo et al., Wide range in estimates of hydrogen emissions from infrastructure, 11 Frontiers in Energy Rsch. 1, at 4 (2023), https://www.frontiersin.org/articles/10.3389/fenrg.2023.1207208/full.
[295] S. McFarlane & R. Bousso, Focus: Has green hydrogen sprung a leak?, Reuters (Dec. 22, 2022), https://www.reuters.com/business/sustainable-business/has-green-hydrogen-sprung-leak-2022-12-22/.
[296] 26 U.S.C. § 45V(c)(2)(B)(i)(III).
[297] 88 Fed. Reg. at 89,246.
[298] M. Sand et al., A multi-model assessment of the Global Warming Potential of hydrogen, 4 Commc'ns Earth & Env't 1, at 1 (2023), https://www.nature.com/articles/s43247-023-00857-8.
[299] D. Hauglustaine et al., Climate benefit of a future hydrogen economy, 3 Commc'ns Earth & Env't 1, at 1 (2022), https://www.nature.com/articles/s43247-022-00626-z.
[300] 42 U.S.C. § 7545(o)(1) (incorporated by reference by § 45V(c)(1)(a)).

urgent given recent analysis surrounding so-called "gold" hydrogen, which is produced by drilling for hydrogen in subsurface geological accumulations. One attempt at a first assessment of the carbon intensity of hydrogen produced in this way claimed a very low GHG intensity, but completely ignored the warming potential of hydrogen itself, even though the study noted that about 10% of gross production is lost as waste gas.[301] Properly accounting for production-stage leakage will both ensure accurate accounting for lifecycle GHG emissions using today's technologies and send helpful market signals to develop future technologies that minimize these harmful leaks.

VII. CONCLUSION

Earthjustice and Sierra Club urge Treasury to finalize the Proposed Rule with the recommendations above to ensure hydrogen producers do not illegally receive tax credits for hydrogen production that is too polluting to meet Section 45V's emissions thresholds. Weak rules would drive dramatic increases in GHG emissions, health-harming pollution, and electricity rates and give dirty hydrogen producers an improper competitive advantage against companies with low-carbon production processes.

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[301] A. R. Brandt, Greenhouse gas intensity of natural hydrogen produced from subsurface geologic accumulations, 7 Joule 1818, at 1820 (2023), https://www.cell.com/joule/abstract/S2542-4351(23)00274-X.