December 2, 2022

U.S. Department of the Treasury, Internal Revenue Service
Office of Tax Policy
Ben Franklin Station
P.O. Box 7604, Room 5203
Washington, DC 20044
Submitted via www.regulations.gov, IRS-2022-0058

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

I. Introduction

The Inflation Reduction Act's clean hydrogen production tax credit ("PTC") is poised to have a seismic impact on the economics of hydrogen production. Earthjustice, Sierra Club, and League of Conservation Voters appreciate the opportunity to provide input on the Internal Revenue Service's ("IRS") implementation of this new tax credit under Internal Revenue Code Section 45V because careful carbon accounting is essential to ensure that taxpayers see meaningful benefits from the hydrogen production they subsidize. As the market deploys capital to take advantage of this PTC, it is essential for the IRS to adopt a robust regulatory framework so that investments in hydrogen production technologies align with the Biden Administration's goal of achieving net-zero carbon emissions by 2050.

The IRS should reject any requests from industry for carbon accounting practices that will allow hydrogen producers to greenwash highly polluting production processes, such as book-and-claim accounting of biogas credits or the use of unbundled renewable energy credits to treat electricity consumption as zero-emissions. These dubious carbon accounting practices would allow hydrogen producers to claim tax subsidies for activities that burden communities with health-harming pollution and destabilize the climate.

II. .01 Credit for Production of Clean Hydrogen

A. Which specific steps and emissions should be included within the well-to-gate system boundary for clean hydrogen production from various resources? (Notice question (1)(a))

The Treasury Department and IRS's well-to-gate system boundary for clean hydrogen production should include, at a minimum, each of the same steps that the U.S. Department of Energy ("DOE") included in its draft guidance on the Clean

Hydrogen Production Standard ("CHPS").[1] DOE's draft guidance specified that the system boundary includes "all key emissions sources associated with feedstock extraction or production, generation of electricity, feedstock delivery, hydrogen production, potential releases during CO_2 transport, and carbon capture and sequestration of GHGs generated by the production process,"[2] as depicted in the following "Figure 1" from the draft guidance:

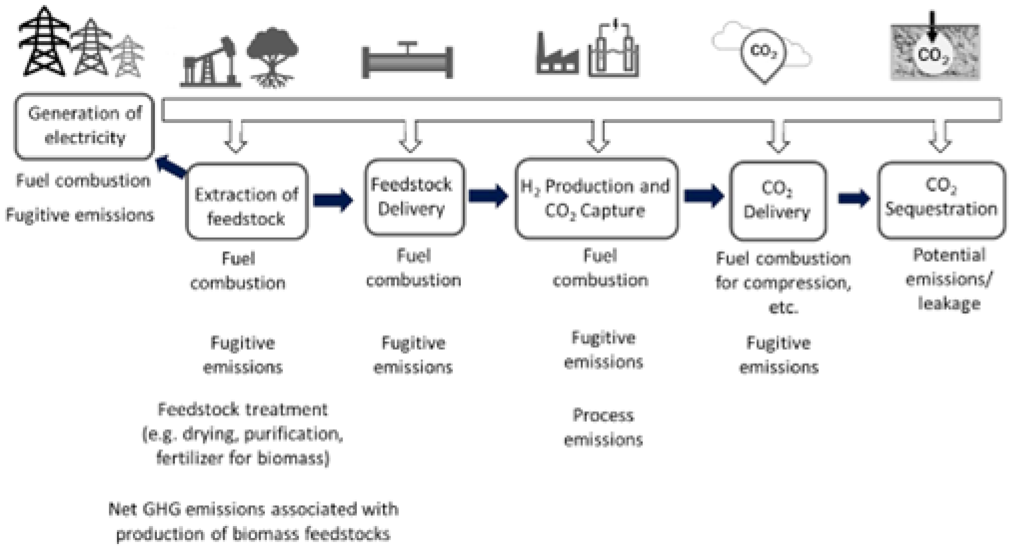

Figure 1: A lifecycle system boundary enables consistent and comprehensive evaluation of diverse hydrogen production systems. Examples of key emission sources within each step typically considered in the boundary are shown above.[11]

In addition to the steps and emissions sources clearly depicted in Figure 1, the well-to-gate system boundary should include emissions associated with delivering methane to gas-fired power plants for hydrogen production that relies on electricity to power a water- or methane-splitting process.[3] It appears that the Treasury Department and IRS have appropriately included those emissions in their well-to-gate system boundary: footnote 3 in Notice 2022-58 states that the system boundary includes "generation of electricity consumed by a hydrogen production

[1] *See* Attachment A, Earthjustice *et al.*, Stakeholder Feedback on Clean Hydrogen Production Standard (CHPS) Draft Guidance (Nov. 14, 2022).
[2] U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance, 4 (Sept. 22, 2022), https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf.
[3] As Earthjustice *et al.* explained in comments on DOE's CHPS draft guidance, DOE should clarify Figure 1 to ensure that those emissions are also included in DOE's well-to-gate system boundary for hydrogen production. Attachment A, Earthjustice *et al.*, Stakeholder Feedback on Clean Hydrogen Production Standard (CHPS) Draft Guidance, 8 (Nov. 14, 2022).

facility (including feedstock extraction for electricity generation, feedstock delivery, and the electricity generation process itself)."[4]

Further, the Treasury Department and IRS should ensure that the lifecycle analysis for all hydrogen production methods that rely on methane from fossil fuels will account for all fugitive emissions from production (including drilling the production wells), gathering, processing, transmission, and storage. Each of these stages of the gas supply chain contributes significant emissions.[5] The GREET model currently underestimates fugitive methane emissions from the fossil gas supply chain, which is an issue we discuss in greater detail in response to question (7), below.

Finally, in addition to the emissions sources explicitly listed in DOE's Figure 1, a rigorous carbon accounting for blue hydrogen must include the emissions impacts of using captured carbon for enhanced oil recovery ("EOR"). Thus, for hydrogen production pathways involving EOR, the well-to-gate system boundary should include the emissions from burning petroleum produced through EOR at the CO_2 sequestration stage.

B. How should lifecycle greenhouse gas emissions be allocated to clean hydrogen that is a by-product of industrial processes, such as in chlor-alkali production or petrochemical cracking? (Notice question (1)(c)(i))

There is no need for the IRS to allocate the lifecycle greenhouse gas emissions for hydrogen that is a by-product of industrial processes because this hydrogen does not meet the IRA's requirements for qualified clean hydrogen. Section 45V(c)(2)(B) explicitly requires that qualified clean hydrogen only includes hydrogen that "is produced . . . for sale or use." By-product hydrogen is not produced for sale or use, but is instead produced as an incidental consequence of making chlorine or other chemicals for sale or use. Argonne National Laboratory has succinctly explained this distinction in its study of the lifecycle emissions of chlor-alkali by-product hydrogen, noting that "most hydrogen produced in the U.S. is on-purpose (not by-product)."[6] The study also explained that this hydrogen would be considered a co-product instead of a by-product if the market price of hydrogen increases so dramatically that it provides "a similar overall value proposition as the other

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[4] Internal Revenue Service, Notice 2022-58, at 5.

[5] Ramón A. Alvarez *et al.*, *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 187, tbl. 1, Science (June 21, 2018) (accounting for a total of 12.72 Tg/year of methane emissions from production, gathering, processing, and transmission and storage), http://science.sciencemag.org/content/361/6398/186.

[6] Argonne National Laboratory, Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants (Dec. 2017) at 1.

products."[7] Under current and foreseeable market conditions (including the foreseeable success of DOE's Hydrogen Shot initiative reducing the cost of clean hydrogen to $1 per kilogram),[8] it would be unreasonable to treat hydrogen from the chlor-alkali process as if it were produced for sale or use. By-product hydrogen is ineligible for clean hydrogen production tax credits under the plain meaning of Section 45V.

C. How should qualified clean hydrogen production processes be required to verify the delivery of energy inputs that would be required to meet the estimated lifecycle greenhouse gas emissions rate as determined using the GREET model or other tools if used to supplement GREET? (Notice question (1)(e))

Electrolytic hydrogen producers seeking tax credits under § 45V should be subject to different processes for verifying the delivery of energy inputs required to meet GREET's lifecycle greenhouse gas emissions rate, depending upon the source of the producers' energy inputs. While the mechanism for verifying delivery of electricity inputs varies across different electricity procurement strategies, accurate carbon accounting for electricity generation emissions must adhere to certain basic principles.[9] First, producers can only properly claim to use zero-emission or renewable electricity if they are relying on new or otherwise curtailed (i.e., additional) renewable resources. Second, producers should only be allowed to claim they are using zero-emission or renewable electricity if they are using the electricity in the same hour and same area that the electricity was generated, absent on-site storage infrastructure. Third, claims regarding the use of zero-emission or renewable electricity are only meaningful if no other entity can claim the renewable attributes of that energy. Fourth, the IRS should treat hydrogen producers that use grid electricity as taking delivery of electricity from their balancing authority's marginal generation resource in the hours they use grid electricity, unless the producer has entered a power purchase agreement for delivery of energy in that time and place.

The following discussion applies these principles to hydrogen producers who use (i) co-located renewable resources, (ii) power purchase agreements to receive renewable electricity via the grid, and (iii) unspecified grid electricity.

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[7] *Id.* at 34 ("What makes hydrogen a by-product is a combined effect of hydrogen price and mass ratio. If hydrogen was $10,000/tonne H2 (or $10/kg H2), for example, it would not be considered a by-product, but a co-product (like chlorine or caustic soda), providing a similar overall value proposition as the other products (chlorine and caustic soda.").

[8] U.S. DOE, Hydrogen Shot, https://www.energy.gov/eere/fuelcells/hydrogen-shot.

[9] *See also* Earthjustice, Response to Notice 2022-49, Request for Comments on Certain Energy Generation Incentives – Comments on Implementing Section 45(e)(13) (Nov. 4, 2022), https://www.regulations.gov/comment/IRS-2022-0023-1842.

(i) Electrolytic hydrogen producers with co-located renewable resources.

One verification process should apply to hydrogen producers that power their electrolyzers with behind-the-meter electricity from co-located renewable resources like wind and solar. These producers should be required to verify the delivery of zero-emission energy inputs by demonstrating the following:

1. The co-located renewable resources are either
    a. (a) newly constructed resources ("additional"); or
    b. (b) existing resources that supply energy to the electrolyzer only when that energy would otherwise be curtailed;
2. The producer timely retired any Renewable Energy Credits or Environmental Attribute Credits ("RECs") associated with the renewable energy that was generated on-site and used for hydrogen production; **and**
3. The co-located renewable resources supplied the hourly electric demand of the hydrogen production facility.

The first requirement (additionality) is important because if hydrogen producers use power from existing renewable resources, the customers who historically purchased the renewable generator's power can shift to relying on fossil-fueled generators. This resource shuffling can defeat the purported benefits of using the renewable resource to power electrolysis, as discussed more in subsection (ii).

The second requirement (REC retirement) ensures that other entities do not also claim the renewable attributes of the same energy.

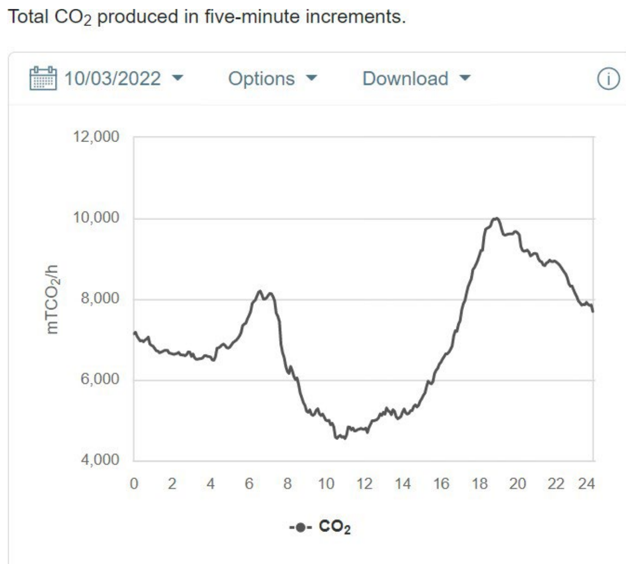
The third requirement (hourly matching) ensures that electrolytic hydrogen producers with co-located renewables cannot take credit for using on-site renewable electricity generation when they actually use electricity from the grid or on-site fossil generators. Protecting against this outcome is important because hydrogen producers have an incentivize to operate their electrolyzers during hours when on-site renewable resources are not generating, which is also when grid electricity has the highest emissions.

Consider the predictable business model of an electrolytic hydrogen producer in California. Electrolytic hydrogen producers in California are likely to co-locate their electrolyzers with solar generation resources.[10] These hydrogen producers may

[10] *See, e.g.*, Green Hydrogen Coalition, *HyBuild Los Angeles: Architecting the Green Hydrogen Ecosystem for a Deeply Carbonized LA*, 3 (Sept. 20, 2022) (predicting the buildout of 26 GW of

seek to increase the capacity factor of their electrolyzers by operating on grid power during the hours when their solar resources are producing little or no energy. Troublingly, the hours when these hydrogen producers have an economic incentive to rely on grid power are the hours when the California grid is the most emissions intensive. For instance, California Independent System Operator ("CAISO") data on the emissions-intensity of its grid on one recent day illustrates a typical daily pattern. Figure 1 shows the trend in CO_2 emissions on October 3, 2022, with dramatic swings over the course of the 24-hour day:[11]

Figure 1: CAISO CO2 Trend on October 3, 2022



An electrolytic hydrogen producer would likely have an incentive to rely on on-site solar resources for energy during the time of day when those zero-emission resources produce the most energy (between 8 a.m. and 4 p.m.), and rely on grid resources to boost electrolyzer capacity factors during the other hours—when the CAISO grid energy is most polluting. Especially because of these incentives, the § 45V verification process must ensure that electrolytic hydrogen producers with co-located renewables cannot claim zero-emission energy inputs when they are in fact relying on grid electricity.

Producers can demonstrate that they meet the third (hourly matching) requirement by installing demand meters that take hourly readings on their

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solar capacity to power California's green hydrogen economy), https://static1.squarespace.com/static/5e8961cdcbb9c05d73b3f9c4/t/6329cedaad25a149bd9e10e4/1663684316020/GHC_HyBuild_Phase_I_20220920.pdf.

[11] CAISO ISO, CO_2 emissions (serving ISO load) (graphic produced by selecting 10/03/2022 in the Total CO2 trend tool), http://www.caiso.com/todaysoutlook/pages/emissions.html.

hydrogen production facilities and by using standard production meters on the renewable generation resources. The hourly electric demand of the hydrogen production facility can be deemed to come from the co-located renewables, up to the amount of on-site production in that hour, minus any energy exported to the grid in that hour.

These producers can also demonstrate that the hourly electric demand of their hydrogen production facilities came from co-located renewables when their facilities run on energy storage resources (such as batteries) that are used to store excess renewable energy. Electricity from a storage resource can be deemed zero-emission if the producer demonstrates that (a) the storage resource never charges during hours when the facility imports electricity from the grid; or (b) the storage resource only charges in hours when the renewable generating resources produce more electricity than the hydrogen production facility demands and excess renewables are not exported to the grid.

(ii) Electrolytic hydrogen producers using grid electricity to deliver renewable energy.

A different verification process should apply to electrolytic hydrogen producers that power their electrolyzers with electricity from the grid. These hydrogen producers should not be allowed to claim a tax credit under § 45V unless they can provide verification that they meet each of the following criteria:

1. The hydrogen producer entered an agreement with a newly-constructed (“additional”) wind or solar facility to purchase energy bundled with RECs;
2. The hydrogen producer timely retired the RECs and no other entity can claim the emissions benefits of the renewable energy;
3. The electric generator associated with the REC is either connected to the same balancing authority as the hydrogen producer or has an agreement to dynamically transfer electricity to the producer’s balancing authority; **and**
4. The hydrogen producer uses the energy in the same hour that the electric generator associated with the REC delivers energy to the grid.

Each of these requirements is essential for ensuring the integrity of any claim of using zero-emission electricity. The first requirement—to contract with new resources—is the most straightforward way for entities claiming emissions benefits to demonstrate additionality. If hydrogen producers buy power from existing renewable resources, the customers who historically purchased the generator’s power can shift to relying on fossil-fueled generators, defeating the purported benefits of using the renewable resource to power electrolysis.

A recent Princeton University study underscores the importance of this additionality requirement. The study modeled emissions from grid-based electrolytic hydrogen production in southern California using varied modeling parameters, including one parameter that required electrolytic hydrogen producers to procure all carbon-free energy from new resources and one parameter that required producers to procure all carbon-free energy from only those resources that could not be counted towards California's capacity installation mandates. When those parameters were removed, the carbon intensity of electrolytic hydrogen production equaled 20 $kgCO_2e/kgH2$ regardless of other parameters that required producers to match their electrolyzer load with renewable generation on an hourly basis.[12]

The second requirement—to retire the RECs associated with hydrogen production—is also essential to ensure additionality. Without retirement of the RECs, it would be easy for multiple entities to take credit for the same environmental benefits of the renewable energy. For instance, if a utility used the RECs to comply with a state renewable portfolio standard, the utility could avoid building new renewable resources that it would have otherwise deployed. In this scenario, the renewable resources that powered the electrolysis would provide little or no climate benefit because they would merely displace other renewables. REC tracking platforms, like the M-RETS platform that is in development, could help ensure that electrolytic hydrogen producers timely retire their purchased RECs and do not claim environmental benefits from RECs that should have already been retired.[13]

The third and fourth requirements—to deliver the renewable energy to the hydrogen producer's balancing authority in the same hour that the producer's electrolyzer is relying on grid power—reflect the reality that the emissions impact of adding the producer's load to the electric grid depends on locational and temporal factors. That is, the emissions impact depends on the marginal unit that is dispatching in the producer's specific balancing authority at the specific time of the load. It would be inappropriate to credit a hydrogen producer for using renewable energy if the producer brings renewable generation online in a different region, displacing generation resources that are less emissions-intensive than the marginal resources the hydrogen producer uses in its balancing area.

The Princeton study reinforces the importance of matching RECs to electrolyzers' energy consumption along temporal factors. When the study's model

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[12] Wilson Ricks *et al.*, *Minimizing Emissions from Grid-Based Hydrogen Production in the United States* (working paper), 15 & Supp. Fig. 19 (Nov. 2022), https://zenodo.org/record/7349406#.Y4OjznbMI2w ("Princeton Study").

[13] *See* M-RETS, Tracking, https://www.mrets.org/about/tracking/; Ben Gerber, M-RETS, *A Path to Supporting Data-Driven Renewable Energy Markets* (Mar. 2021), https://www.mrets.org/wp-content/uploads/2021/02/A-Path-to-Supporting-Data-Driven-Renewable-Energy-Markets-March-2021.pdf.

required electrolytic hydrogen producers to match their consumption of grid power with procured carbon-free generation at every hour of the year (combined with additionality and deliverability[14] requirements), the hydrogen's emissions intensity was consistently low.[15] By contrast, when the model placed no temporal matching requirements on electrolytic hydrogen producers, the emissions intensity of electrolytic hydrogen exceeded even the minimum PTC threshold—often reaching double the intensity of grey hydrogen, and in one instance, reaching nearly four times the intensity of grey hydrogen.[16] Notably, requiring producers to match 100% of their consumption of grid power with procured carbon-free generation on either a weekly or annual basis (rather than hourly) was "universally ineffective at reducing consequential emissions from grid-based hydrogen production," resulting in emissions intensities that rarely met even the minimum PTC threshold and often far exceeded it.[17]

The Princeton study also demonstrates the importance of requiring electrolytic hydrogen producers to procure their carbon-free energy from local sources. When transmission lines are congested, different marginal units will be called upon on either side of the constraint. This can lead to divergent emissions impacts—for example, the marginal unit could be a carbon-free resource on one side of the constraint and a fossil generator on the other. As a result, "clean resources subject to transmission constraints that prevent delivery of the procured energy cannot be relied on to eliminate emissions from hydrogen production."[18] Due to the impact of both temporal and locational factors on electrolytic hydrogen's emissions intensity, the Princeton study concludes that a "100% Hourly Matching requirement" (including locational/deliverability and additionality requirements) "is [] likely to be the best practical means of minimizing the real emissions impact of grid-based hydrogen production in the US."[19]

Matching RECs according to the time and place of an electrolyzer's load is feasible, and reasonable to require of hydrogen producers. Companies like M-RETS and EnergyTag are in the process of developing REC tracking platforms to enable hourly matching between REC generation and energy use.[20] Google became the first REC purchaser to make an hourly retirement claim through the M-RETS tracking platform in 2021.[21] California's Renewable Portfolio Standard incorporates a geographical requirement by requiring delivery of electricity from renewable resources into the balancing areas where the benefits of those resources are

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[14] The study uses the term "deliverability" for requirements related to the location of carbon-free energy sources.
[15] Princeton Study at 9-12, *supra* n. 12.
[16] *Id.* at 8-10.
[17] *Id.* at 10, 12-13.
[18] *Id.* at 14.
[19] *Id.* at 12.
[20] *Supra* n. 13; *see also* EnergyTag, https://energytag.org/.
[21] Gerber at 1, *supra* n. 13.

claimed.[22]

Currently, all grid operators do not have electricity wheeling frameworks that would allow hydrogen producers to enter power purchase agreements with renewable resources and have their renewable electricity delivered in the hours when the hydrogen producer demands electricity. The inability of hydrogen producers in some regions to meaningfully claim the use of renewable energy from the grid is not a rationale for the Treasury Department or IRS to adopt a carbon-intensity verification process that is inconsistent with the plain meaning of the statute or that caters to the lowest common denominator. Instead, in regions where power purchase agreements are infeasible, hydrogen production facilities should be required to use electricity from co-located renewable generation resources. A rigorous carbon-intensity verification process will encourage hydrogen producers in regions that now lack wheeling options to work with grid operators and other stakeholders to develop new wheeling frameworks that meet whatever bar the Treasury Department and IRS set.

(iii) Determining the proper emissions accounting for electricity delivered via the electric grid will generally require an update to the GREET model to include data relevant to the marginal emissions of the hydrogen producer's electric load, with appropriate temporal and spatial granularity.

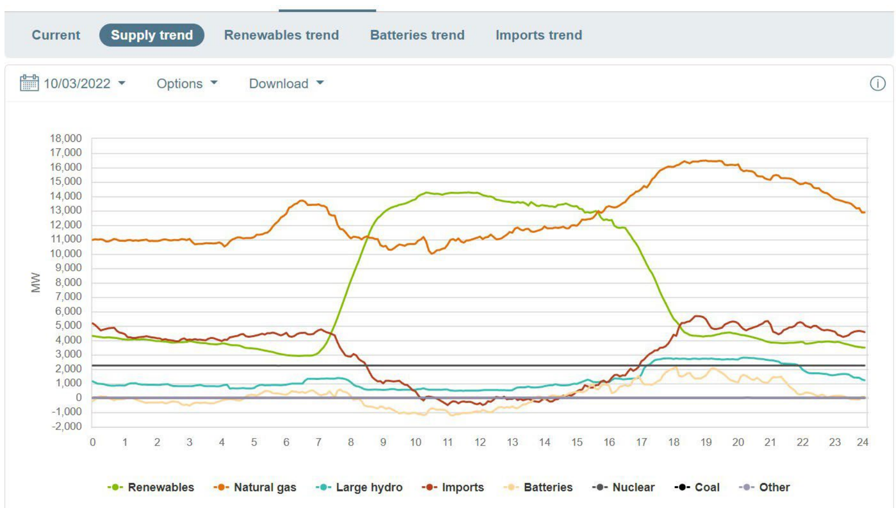
For the reasons discussed in subsections (i) and (ii), estimating the true carbon intensity of grid-based electrolytic hydrogen production requires granular data on the time and place of renewable energy generation and electrolyzer load. The GREET model currently uses annual average emissions data to estimate the carbon intensity of grid electricity, which is insufficiently granular.[23] Electrolytic hydrogen producers should not be allowed to verify the carbon intensity of their energy inputs by relying on GREET's annual average emissions data because that would significantly underestimate the pollution impacts of hydrogen production. The emissions intensity of a grid varies drastically over time, with relatively predictable daily and seasonal swings. Reliance on grid-average emissions data to estimate emissions from electrolytic hydrogen production is likely to systemically underestimate emissions because producers will have an incentive to use grid electricity during the times of day when fossil generators are the marginal unit and the grid emissions are higher than average. This is true even of electrolytic hydrogen producers with co-located renewables, as the above example of an electrolytic hydrogen producer in California illustrates.

[22] Cal. Pub. Utils. Code § 399.16(b)-(c).
[23] GREET's annual average approach is described in J. Kelly *et al.*, Argonne Nat'l Lab'y, Updating Electric Grid Emissions Factors, 1 (2016) ("An annual average approach is employed, while acknowledging that time-of-use considerations are important to identifying exactly which electrical generating units are being utilized at any specific moment in time.").

Instead of relying on annual average emissions, electrolytic hydrogen producers should be required to verify the carbon intensity of their energy inputs by using the emissions from the marginal unit in their balancing authority during the hour the producer is demanding grid electricity. This approach makes sense because the emissions from running an electrolyzer on grid power are a function of the emissions from the marginal unit on the grid of the hydrogen producers' balancing authority during the time the electrolyzer demands grid power. Average emissions data obscures this fact and skews the emissions impact of the electrolyzer's additional load by including data for zero-emission resources that would have generated the same amount of electricity regardless of whether the electrolyzer load were on the grid.

CAISO data can illustrate the danger in relying on average emissions data, even for a particular hour. Figure 2 shows how much different types of generation resources contributed to CAISO's electricity supply in each hour of October 3, 2022:[24]

Figure 2: CAISO Supply Trend on October 3, 2022



In each hour of the day, the California grid supply includes over 2 GW of zero-emission nuclear energy. Using an average emissions figure that includes inflexible nuclear resources improperly suggests that these resources could ramp up to meet a proportionate share of the new load from hydrogen producers. In fact, new load during hours of minimal solar production is likely to be served by ramping up in-state gas-fired generators or increasing imports (largely from out-of- state gas-fired generators).

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[24] CAISO, Supply trend (graphic produced by selecting 10/03/2022 in the Supply trend tool), http://www.caiso.com/todaysoutlook/pages/supply.html#section-supply-trend.

A similar pattern exists in other regions. As the Institute for Policy Integrity ("IPI") and WattTime explained in recent comments on DOE's CHPS draft guidance, using annual average emissions data would significantly underestimate the emissions intensity of electrolytic hydrogen production in the Pacific Northwest due to that region's abundant zero-emission hydroelectric generation: "[b]ecause there is not enough hydropower to meet the full regional demand for electricity, adding load in the Pacific Northwest from an electrolyzer would require more electricity generation from some other resource to meet total demand, likely a coal or natural gas plant."[25] IPI and WattTime's comments also explain that during one sample period in April 2022, the marginal emissions often oscillated between zero and approximately 800 lbs CO_2/MWh in CAISO and between zero and 1,400 lbs CO_2/MWh in Southwest Power Pool ("SPP"), demonstrating "how dramatic the misestimation could be if an annual-average approach were used instead of an hourly or sub-hourly marginal emissions approach."[26]

By incorporating improved assumptions to the GREET model based on hourly marginal emissions data (instead of annual average emissions data), GREET could better estimate the true carbon intensity of grid-based electrolytic hydrogen production. Improving GREET is feasible: California's GREET model already enables more granular and accurate estimates of the carbon intensity of grid-based electrolytic hydrogen production by using average hourly emissions data from a model developed for proceedings at the California Public Utilities Commission.[27]

Several data sources could supply the GREET model with improved assumptions. Data sources on both average and marginal hourly emissions are growing, and this trend is likely to continue given the mandate in the Infrastructure Investment and Jobs Act that the Energy Information Administration expand its data collection to include marginal emissions rates for each balancing authority and pricing node.[28] PJM Interconnection and ISO New

[25] IPI & Wattime, Comments on U.S. DOE's Clean Hydrogen Production Standard Draft Guidance, 3 (Nov. 4, 2022), https://policyintegrity.org/documents/Institute_for_Policy_Integrity___WattTime_Comments.pdf.
[26] *Id.*
[27] CARB, CA-GREET3.0 Lookup Table Pathways: Technical Support Documentation, 27-28 (Aug. 13, 2018), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut-doc.pdf (showing the average, marginal carbon intensity values associated with grid-based electrolytic hydrogen production for each hour of the day, for the four quarters of the year). These carbon intensity values were determined using the "Avoided Cost Calculator," which "produces an hourly set of values over a 30-year time horizon that represent costs that the utility would avoid if demand-side resources produce energy in those hours." *See* Energy + Environmental Economics, Avoided Cost Calculator User Manual, 1 (Aug. 2016), https://ww2.arb.ca.gov/sites/default/files/2020-06/acc_user_manual.pdf.
[28] Now codified at 42 U.S.C. § 18772(a)(2)(B)(ix) ("[T]he Administrator shall expand the Dashboard to include, to the maximum extent practicable, hourly operating data," including "where available, the estimated marginal greenhouse gas emissions per megawatt hour of electricity generated [] (I) within the metered boundaries of each balancing authority; and (II) for each pricing node.").

England already report marginal emissions in five-minute increments,[29] and SPP and MISO already collect and report data on the marginal fuel source.[30] The REC tracking platform M-RETS has also started collecting average hourly generation data, mostly from MISO, and plans to start collecting more granular data on marginal fuel and avoided carbon emissions.[31] Several other sources of marginal hourly emissions are available or in development.[32]

While these data sources are in development, balancing authorities could directly supply more granular emissions data for incorporation in GREET. As Earthjustice et al. explained in recent comments on DOE's CHPS draft guidance, DOE could request data from each balancing authority on the marginal unit during each hour of the year for the most recent year that this data is available.[33] Using this dataset, DOE could calculate the average emissions from adding a MWh of new load to that grid during each of the twenty-four hours in a day in a recent year (i.e., average marginal emissions at the hours starting at midnight, 1 a.m., 2 a.m., etc.). This approach would fail to recognize seasonal and day-to-day variation, but it provides ease of administrability. Improved granularity is possible through seasonal analysis.[34]

Given the multiple viable pathways to improving GREET's accuracy through use of more granular emissions data, the Treasury Department and IRS should make clear in the § 45V guidance that electrolytic hydrogen producers will not be allowed to rely on GREET's annual average emissions data, and instead, will need to verify the carbon intensity of their energy inputs by using the emissions from the marginal unit in their balancing authority during the hour the producer is demanding grid electricity.

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[29] PJM Interconnection, Five Minute Marginal Emission Rates, https://dataminer2.pjm.com/feed/fivemin_marginal_emissions/definition; ISO-New England, https://www.iso-ne.com/search/?file-type=XLS&file-type=XLSX&file-type=CSV&file-type=xls&file-type=xlsx&file-type=csv&query=emission%20rates.

[30] SPP, Fuel on the Margin, https://marketplace.spp.org/pages/fuel-on-margin; MISO, Market Reports, Real-Time Fuel on the Margin, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Fuel%20on%20the%20Margin%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc.

[31] Gerber at 1, 16, 19, 22, *supra* n. 13.

[32] *See* Karen Palmer *et al.*, Resources for the Future, *Options for EIA to Publish CO_2 Emissions Rates for Electricity*, 21–25 (Aug. 2022), https://media.rff.org/documents/Report_22-08.pdf (describing data sources on hourly emissions and accounting methodologies).

[33] *See* Attachment A, Earthjustice *et al.*, Stakeholder Feedback on Clean Hydrogen Production Standard (CHPS) Draft Guidance (Nov. 14, 2022).

[34] *See, e.g.*, CARB, CA-GREET3.0 Lookup Table Pathways: Technical Support Documentation, 27-28, *supra* n. 27.

(iv) Allowing hydrogen producers to use unbundled RECs to characterize electricity inputs would improperly allow taxpayers to claim credits for producing hydrogen that is far more carbon-intensive than qualified clean hydrogen, as defined in Section 45V.

Given the importance of temporal and locational factors, electrolytic hydrogen producers that use grid electricity should **not** be allowed to use unbundled RECs to verify the carbon intensity of their energy inputs. Allowing these producers to claim that their energy inputs are zero-emission based on the purchase of unbundled RECs could have devastating impacts on the climate, and could dramatically increase climate and criteria pollution. Even on a relatively clean grid like California's, the California Air Resources Board has determined that electrolytic hydrogen produced with grid-average electricity is a far more carbon-intensive fuel than diesel or compressed fossil gas.[35] The Princeton study similarly found that "[u]sing the current average US generation mix, embodied emissions from grid-connected electrolysis would be far too high to meet statutory requirements for even the minimum PTC."[36] Thus, if hydrogen producers were allowed to characterize their hydrogen as zero-emission when it is produced from fossil-fueled grid electricity, they could seek lucrative tax credit to produce a fuel that is even more damaging to the climate than the fossil fuels currently in use.

Hydrogen producers would see a powerful incentive to take advantage of this opportunity, even though unbundled RECs do not eliminate emissions from a production facility's grid power. Unbundled RECs are so cheap that electricity users can pair them with dirty grid energy at a cost that represents a 1-2% premium on the price of electricity.[37] The climate benefits of these REC purchases are unsubstantiated. As a recent article in Nature Climate Change explained, a reported emissions reduction is "not real" when an electricity user purchases RECs that "do not lead to the generation of additional renewable energy."[38] Moreover, "there is a risk of double counting the emission benefits of renewable energy

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[35] California Air Resources Board, Table 7-1: Lookup Table for Gasoline and Diesel and Fuels that Substitute for Gasoline and Diesel (listing 164.46 gCO2e/MJ as the carbon intensity of compressed hydrogen produced through electrolysis with California average grid electricity, 100.45 gCO2e/MJ as the carbon intensity of diesel fuel in California, and 79.21 gCO2e/MJ as the carbon intensity of compressed gas from average North American fossil gas), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut.pdf.

[36] Princeton Study at 2, *supra* n. 12 (finding that "electrolysis with an efficiency of 50 kWh/kgH_2 using 100% gas-fired electricity (~0.4 $kgCO_2/kWh$) would produce hydrogen at an embodied emissions rate of roughly 20 $kgCO_2e/kgH_2$, or double that of SMR") (citations omitted).

[37] Gautam Naik, *Problematic Corporate Purchases of Clean Energy Credits Threaten Net Zero Goals*, S&P Global (May 5, 2021), https://www.spglobal.com/esg/insights/problematic-corporate-purchases-of-clean-energy-credits-threaten-net-zero-goals.

[38] Anders Bjorn *et al.*, *Renewable Energy Certificates Threaten the Integrity of Corporate Science-Based Targets*, 540, Nature Climate Change (June 9, 2022), https://www.nature.com/articles/s41558-022-01379-5.

generation" if one entity claims the benefits of specific zero-emission generation based on a REC purchase, while "other companies count that same renewable energy [based on] the grid average emission factor in their [region]."[39] Therefore, hydrogen producers must not be allowed to use unbundled RECs to claim that their electricity is zero-emission, as producers would have a strong incentive to characterize their electricity as renewable using questionable carbon accounting techniques instead of developing the resources necessary for truly zero-carbon hydrogen production.

D. What technologies or accounting systems should be required for taxpayers to demonstrate sources of electricity supply? (Notice question (4)(c))

By default, hydrogen producers that use electricity from the electric grid should be deemed to be using electricity supplied by the marginal generation resource in the balancing area where their facility is located during the hour that the facility takes the energy from the grid. The IRS, DOE, and Argonne National Laboratory should coordinate to develop an updated version of GREET that includes data for these time- and place-dependent emissions.

The IRS can reasonably allow hydrogen producers who take electricity from the grid to claim lower emissions for that electricity if they enter an agreement with a newly-constructed wind or solar facility to purchase energy bundled with RECs; timely retire the RECs and no other entity can claim the emissions benefits of the renewable energy; the electric generator associated with the REC is either connected to the same balancing authority as the hydrogen producer or has an agreement to dynamically transfer electricity to the producer's balancing authority; **and** the hydrogen producer uses the energy in the same hour that the electric generator associated with the REC delivers energy to the grid.

These issues are discussed in greater detail in Earthjustice, Sierra Club, and League of Conservation Voters's response to question (1)(e).

E. Should indirect book accounting factors that reduce a taxpayer's effective greenhouse gas emissions (also known as a book and claim system), including, but not limited to, renewable energy credits, power purchase agreements, renewable thermal credits, or biogas credits be considered when calculating the § 45V credit? (Notice question (4)(f))

The IRS should not allow hydrogen producers to claim tax credits based on indirect claims to renewable energy credits or biogas credits. The plain language of Section 45V defines "qualified clean hydrogen" based on the lifecycle emissions from the hydrogen's production process. The statute only provides tax credits to entities

[39] *Id.* at 543.

that produce hydrogen "through a process that results in a lifecycle greenhouse gas emissions rate of no greater than 4 kilograms of CO2e per kilogram of hydrogen."[40] Section 45V incorporates the definition of lifecycle greenhouse gas emissions in Section 211(o)(1)(H) of the Clean Air Act. Under this definition, the lifecycle greenhouse gas emissions for a fuel are the "aggregate quantity of greenhouse gas emissions" from "all stages of fuel and feedstock production and distribution." This definition plainly requires the IRS to tabulate lifecycle greenhouse gas emissions by aggregating emissions from these production stages, but does not provide for subtracting any portion of these emissions based on offset credits. Accordingly, in administering the Renewable Fuels program under Clean Air Act Section 211, the Environmental Protection Agency ("EPA") has not permitted fuel producers to use book-and-claim accounting or offsets to characterize the emissions from different stages of the fuel production process. It would be improper for the IRS to allow taxpayers to use such offset schemes to characterize the lifecycle emissions from hydrogen production. Hydrogen produced through a process that emits more than 4 kilograms of CO2e per kilogram of hydrogen does not fit the plain meaning of the statutory definition of qualified clean hydrogen, regardless of whether the taxpayer purchases some sort of offset credit for their emissions.

Book-and-claim accounting would also undermine the apparent purpose of the clean hydrogen production tax credits by providing hydrogen producers an incentive to continue business-as-usual to produce highly polluting hydrogen instead of investing in real clean hydrogen. California's Low Carbon Fuel Standard illustrates this danger. The program allows hydrogen producers to characterize hydrogen as renewable by coupling the use of fossil gas with the purchase of the "environmental attributes" of biogas.[41] The legal fiction that these facilities produce renewable hydrogen allows them to generate valuable credits.[42] The hydrogen production industry has responded to this incentive structure by producing almost all its purportedly "renewable hydrogen" from fossil fuels.[43] The program has not spurred any meaningful investment in clean hydrogen production technologies. If the IRS allowed hydrogen producers to claim tax credits based on book-and-claim accounting, it would risk a repeat of this cautionary tale—contrary to both the text

[40] IRC § 45V(c)(2).
[41] Title 17, Code of Cal. Regs. § 95488.8(i)(2).
[42] *Id.* § 95486.1(f).
[43] *See, e.g.*, John Eichman & Francisco Flores-Espino, *California Power-to-Gas and Power-to-Hydrogen Near-Term Business Case Evaluation*, at 59, National Renewable Energy Laboratory (Dec. 2016) ("Senate Bill 1505 in California requires that 33.3% of hydrogen produced for or dispensed by state-funded fueling stations must be made from eligible renewable resources. At present, the majority of the required renewable hydrogen is produced from SMR and coupled with the purchase of biogas credits."), https://www.nrel.gov/docs/fy17osti/67384.pdf.

of Section 45V and the policy goal of incentivizing investments in clean hydrogen production.[44]

Similarly, it would be improper for the IRS to allow a taxpayer who uses electricity to produce hydrogen to use purchases of unbundled renewable energy credits to claim a lower lifecycle emissions rate than its actual production emissions. The economics and illusory benefits of unbundled renewable energy credits are discussed more fully in response to question (1)(e). Electrolytic hydrogen that relies on electricity produced from fossil fuels is not "produced through a process that results in a lifecycle greenhouse gas emissions rate of not greater than 4 kilograms of CO2e per kilogram of hydrogen,"[45] regardless of whether the taxpayer purchases renewable energy credits from an unrelated project.

The question also asks about power purchase agreements, which can provide a meaningful option for producing clean hydrogen if the contracts are structured properly. It would be appropriate to give hydrogen producers credit for renewable energy procured in a power purchase agreement under the conditions discussed in response to question (1)(e). The IRS must ensure the taxpayer is using additional renewable resources that are delivered in real-time to the grid that serves their facility and that no other entity can take credit for the renewable attributes of that energy.

F. What factors should the Treasury Department and the IRS consider when providing guidance on whether a facility is "designed and reasonably expected to produce qualified clean hydrogen"? (Notice question (6)(b)(ii))

Currently, there is no commercially available technology that can provide a reasonable basis for expecting a facility will produce qualified clean hydrogen using a fossil fuel feedstock. DOE estimates that a facility producing hydrogen through steam reformation of fossil gas could achieve lifecycle greenhouse gas emissions of 4

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[44] Moreover, widespread reliance on offset and crediting schemes to treat fossil gas as if it were biomethane would be inconsistent with DOE's draft National Clean Hydrogen Strategy and Roadmap, which does not identify biomethane as a priority feedstock for clean hydrogen production. DOE, *National Clean Hydrogen Strategy and Roadmap*, at 68 (Draft Sept. 2022) (assessing the potential availability of five renewable resources that could be used for clean hydrogen production, not including biomethane), https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf.

[45] According to carbon accounting that the California Air Resources Board has performed to assess emissions from producing compressed electrolytic hydrogen with electricity from California's relatively clean grid, such hydrogen as a carbon intensity of 164.46 gCO_2e/MJ, which equates to 19.7 $kgCO_2e/kg\text{-}H_2$. California Air Resources Board, Table 7-1: Lookup Table for Gasoline and Diesel and Fuels that Substitute for Gasoline and Diesel, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut.pdf.

$kgCO_2e/kg\text{-}H_2$.[46] However, the limited public data on capture rates at steam methane reformation facilities show that capture rates range from 54% to 90%.[47] Measurements at a Shell facility in Alberta found a mean capture efficiency of 78.8%, with daily rates varying from 54% to 90%, except for one outlier of 15%.[48]

Taxpayers will need to show significant improvement in the state of carbon capture technology before there can be a reasonable expectation that a facility will produce qualified clean hydrogen from fossil fuels. Reasonable expectations that the technology can achieve the claimed carbon capture rates should be based on a demonstration of the complete system under expected operating conditions over a 12-month period. Previous efforts to demonstrate carbon capture technologies have faced significant challenges, in part, because of the carbon capture equipment's high outage rates.[49] Consequently, reasonable expectations regarding carbon capture equipment's performance must be based its operation over a prolonged period.

Independent review and contractual assurances of the performance of the carbon capture equipment are also essential for a reasonable expectation that a facility could produce qualified clean hydrogen from fossil fuels. Taxpayers should be required to submit with an affidavit from an independent qualified engineer that the carbon capture system is designed and reasonably expected to achieve the claimed capture rates. Demonstration of contractual assurances should include the name of the vendor of any carbon capture equipment, design specifications, and the vendor's warranty.

A reasonable expectation of clean hydrogen production at a facility relying on carbon capture would also require a demonstration of how the captured carbon will be stored in perpetuity. There are significant challenges to permanently sequestering carbon dioxide, including its corrosive chemical properties and the potential for carbon dioxide injection to create fissures that allow leakage. The IRS should require taxpayers to demonstrate a scientifically appropriate and thorough characterization of the subsurface before injection begins which includes: (1) multiple years of baseline subsurface studies including seismic surveys; (2) assessments of the storage strata in terms of capacity; (3) assessments of the extent and characteristics of the cap rock; (4) assessments of any groundwater layers

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[46] U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance, at 3, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf.
[47] Robert W. Howarth & Mark Z. Jacobson, *How green is blue hydrogen?*, at 1680, Energy Sci. & Eng'g (July 26, 2021), https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956.
[48] *Id.*
[49] For instance, over the course of three years, problems with carbon capture equipment at the Petra Nova coal-fired power plant caused 104 days of outages, with numerous additional outages resulting from issues with the cogeneration facility that powered the carbon capture facility and the offtaker's inability to receive the captured carbon dioxide. Greg Kennedy, *W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)*, at 8, 41-42, U.S. Department of Energy (Mar. 2020), https://doi.org/10.2172/1608572.

between the surface and the injection point; and (5) multiple years of baseline measurements of carbon dioxide in the ambient air to establish these levels.

G. Please provide comments on any other topics related to § 45V credit that may require guidance. (Notice question (7))

The IRS should collaborate with the DOE and Argonne National Laboratory to update flawed assumptions in the GREET model, provide public notice of those activities, and establish a transparent process for stakeholder engagement. Updating GREET's assumptions regarding methane leakage from the gas sector is critical to the integrity of determining the lifecycle greenhouse gas emissions from hydrogen production. Currently, GREET assumes that only ~1% of methane is lost to fugitive emissions upstream of a hydrogen production facility. This estimate relies on self-reported industry data in EPA's greenhouse gas inventory to estimate fugitive emissions from gas production. The peer-reviewed literature contradicts the assumption that ~1.1% of methane from the gas supply chain is lost to leakage. One reputable source for data on the industry's methane leakage is a 2018 study by Alvarez *et al.*, which relies on in-field measurements.[50] GREET relies on to estimate emissions from certain stages of the gas supply chain (i.e., gathering, processing, and transmission).[51] However, GREET dramatically underestimates overall leakage because of it relies on unreliable data sources for its assumption regarding production-stage emissions,[52] which contribute about 60% of the fugitive emissions from the supply chain upstream of a hydrogen production facility according to Alvarez's measurements.[53] Overall, Alvarez estimates that 2.3% of gross U.S. gas production is lost to fugitive emissions.[54] At a minimum, the integrity of GREET requires updating assumptions on fugitive methane emissions so that they rely on measurement data provided without the cooperation of industry.[55] Incorporation of 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%.[56]

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[50] Ramón A. Alvarez *et al.*, *Assessment of methane emissions from the U.S. oil and gas supply chain*, Science (June 21, 2018) ("Alvarez 2018"), http://science.sciencemag.org/content/361/6398/186.
[51] Andrew Burnham, *Updated Natural Gas Pathways in GREET 2021*, at 5, Table 3, Argonne National Laboratory ("GREET 2021 NG Update") (Oct. 2021), https://greet.es.anl.gov/publication-update_ng_2021.
[52] *See id.*
[53] Alvarez 2018 at 187, Table 1.
[54] *Id.* at 186.
[55] *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).
[56] Attachment A, Earthjustice *et al.*, Stakeholder Feedback on Clean Hydrogen Production Standard (CHPS) Draft Guidance, 3-4 (Nov. 14, 2022).

In response to question (1)(e), Earthjustice, Sierra Club, and League of Conservation Voters also discuss the need to improve the GREET model to estimate emissions from electricity generation with reasonable accuracy. Specifically, to estimate lifecycle greenhouse gas emissions from electrolytic hydrogen that relies on unspecified grid power, GREET will need to account for the emissions from the marginal unit for the time and area of the hydrogen producers' electric load.

Flaws in the current GREET model systemically underestimate the emissions from hydrogen production, creating the risk that investors may assume these flaws will remain in perpetuity and that capital will flow to hydrogen production technologies that are too polluting to qualify as clean hydrogen. The IRS and its inter-agency partners should promptly clarify their intention to update GREET to reflect the best information available.

Respectfully submitted,

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Attachment A

Earthjustice *et al.*, Stakeholder Feedback on Clean Hydrogen Production Standard (CHPS) Draft Guidance (Nov. 14, 2022)

November 14, 2022

U.S. Department of Energy
Hydrogen and Fuel Cell Technologies Office
Submitted electronically to Cleanh2standard@ee.doe.gov by: Sara Gersen, Earthjustice

Re: Stakeholder Feedback on Clean Hydrogen Production Standard (CHPS) Draft Guidance

350 New Mexico, California Environmental Justice Alliance, Center for Biological Diversity, Communities for a Better Environment, Earthjustice, Greenlining Institute, New York City Environmental Justice Alliance, San Juan Citizens Alliance, Sierra Club, and Western Environmental Law Center appreciate the opportunity to provide feedback on the Department of Energy's ("DOE" or "Department") draft guidance on the Clean Hydrogen Production Standard ("CHPS"). The Bipartisan Infrastructure Law creates a unique opportunity for DOE to invest in the improvement and deployment of zero-emission hydrogen production technologies that could help achieve the Paris Climate Agreement's goal of limiting warming to 1.5°C. As DOE observes in its draft National Clean Hydrogen Strategy and Roadmap, we are in "a decisive decade for the world to confront climate change and avoid the worst and irreversible impacts of the crisis by keeping the goal of a 1.5-degree Celsius limit on global average temperature rise within reach."[1] Zero-emission hydrogen production technology is commercially available and ready to scale. This technology relies entirely on new, dedicated renewable resources to power electrolysis. DOE should not squander scarce public resources on technologies with no role in a feasible long-term strategy for limiting warming to 1.5°C. A stringent CHPS and rigorous carbon accounting in CHPS implementation are necessary to direct funding to projects that will most likely contribute to this deep decarbonization target.

The discretion to fund projects that "demonstrably aid achievement" of the CHPS should motivate DOE to adopt an ambitious standard that will push industry to improve the environmental performance of the cleanest hydrogen production technologies. To that end, DOE should adopt a CHPS of lifecycle emissions no greater than 1 $kgCO_2e/kgH_2$. Even when lifecycle emissions are factored in that account for constructing renewable generation facilities, most green hydrogen can meet this threshold. The trade association, Hydrogen Council, for instance, estimates that in 2030, emissions intensity will be approximately 1.0 $kgCO_2e/kgH_2$ for large solar, 0.5 $kgCO_2e/kgH_2$ for onshore wind, and 0.3 $kgCO_2e/kgH_2$ for run-of-river hydropower.[2] If DOE intends to use the CHPS as an aspirational standard, it would not be reasonable to set a weak standard that scalable commercial technologies can already exceed.

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[1] DOE, *National Clean Hydrogen Strategy and Roadmap*, at 11 (Draft Sept. 2022) ("National Hydrogen Roadmap"), https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf.

[2] Hydrogen Council, *Hydrogen decarbonization pathways: A life-cycle assessment*, at 6 (Jan. 2021), https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf. In contrast to the Hydrogen Council's carbon accounting, the GREET model excludes emissions associated with constructing renewable power generation facilities. Consequently, GREET estimates that hydrogen produced by electrolyzers powered by renewable has a carbon intensity of 0 $kgCO_2e/kgH_2$. Argonne National Laboratory, Hydrogen Life-Cycle Analysis in

Although DOE proposed a standard of 4 $kgCO_2e/kgH_2$ because the Inflation Reduction Act ("IRA") provides tax credits for such hydrogen, these tax credits do not dictate the appropriate stringency of the CHPS. Indeed, the legislative decision to subsidize hydrogen with a carbon intensity of 4 $kgCO_2e/kgH_2$ means that this emissions-intensive hydrogen will continue to receive federal support even if DOE adopts an ambitious CHPS. Further, DOE will use the CHPS to direct hydrogen hub funding that serves a different purpose than the IRA's tax subsidies. While tax subsidies are a blunt tool for encouraging certain activities, the hydrogen hubs are part of a technology demonstration program that depends on expertise to select the technologies that are the most appropriate beneficiaries of public funds. In this role, it would be responsible for DOE to support demonstration of technologies that can feasibly scale in pathways that are consistent with achieving the Biden Administration's goal of achieving net-zero carbon emissions no later than 2050.[3]

In addition, carbon standards alone are insufficient to ensure that hydrogen production is truly "clean." The final CHPS should include strict emissions limits on criteria pollution and hazardous air pollution. These limits are essential to prevent hydrogen production facilities from harming public health in neighboring communities.

The CHPS will only direct public investment to technologies that are compatible with the Biden Administration's long-term decarbonization goals if DOE uses rigorous carbon accounting practices to ensure producers cannot make unsubstantiated claims regarding the carbon intensity of their hydrogen. In response to several questions in the CHPS Draft Guidance, the following comments discuss measures DOE should take to ensure its carbon accounting practices are reliable.

1.a. Many parameters that can influence the lifecycle emissions of hydrogen production may vary in real-world deployments. Assumptions that were made regarding key parameters with high variability have been described in footnotes in this document and are also itemized in the attached spreadsheet "Hydrogen Production Pathway Assumptions." Given your experience, please use the attached spreadsheet to provide your estimates for values these parameters could achieve in the next 5-10 years, along with justification.

No comment.

1.b. Lifecycle analysis to develop the targets in this draft CHPS were developed using GREET. GREET contains default estimates of carbon intensity for parameters that are not likely to vary widely by deployments in the same region of the country (e.g., carbon intensity of regional grids, net emissions for biomass growth and production, avoided emissions from the use of waste-stream materials). In your experience, how accurate are these estimates, what are other reasonable values for these estimates and what is your justification, and/or what are the uncertainty ranges associated with these estimates?

Support of Clean Hydrogen Production, at 12, Figure 2 (Oct. 2022), https://greet.es.anl.gov/publication-hydrogenreport2022.

[3] National Hydrogen Roadmap at 11.

i. Fugitive methane.

GREET's assumption that only ~1% of methane is lost to fugitive emissions upstream of a hydrogen production facility is contradicted by the peer-reviewed literature. In a 2021 update to GREET, Argonne National Laboratory adjusted its assumptions for some stages of the oil and gas supply chain (i.e., gathering, processing, and transmission) to account for data from a 2018 peer-reviewed study by Alvarez, et al.[4] However, GREET does not incorporate Alvarez's measurement data for most production-stage emissions.[5] This skews the overall estimate for fugitive methane emissions, as production-stage emissions are both an enormous source of emissions and a source that the U.S. Environmental Protection Agency ("EPA") greenhouse gas ("GHG") inventory has drastically underestimated. Alvarez's data indicates that production activities contribute about 60% of the fugitive emissions from the production, gathering, processing, transmission, and storage stages of the gas supply chain.[6] The measurement data examined in Alvarez's paper indicate that production activities contribute 7.6 Tg/year of methane emissions—more than twice the 3.5 Tg/year estimated in the EPA inventory.[7] Alvarez's approach is more likely to yield accurate results than the methodology EPA used to create its inventory (which GREET relies on for production-stage emissions) because Alvarez's measurements did not depend on the fossil fuel industry's cooperation.[8] Overall, Alvarez estimates that 2.3% of gross U.S. gas production is lost to fugitive emissions.[9]

Even if GREET were to fully incorporate Alvarez's findings, there is a risk that Alvarez's "bottom-up" approach may underestimate fugitive emissions. The Intergovernmental Panel on Climate Change ("IPCC") has cautioned that "national inventories based on 'bottom-up' studies can grossly underestimate emissions and 'top-down' measurement-based assessments of reported emissions will be required for verification."[10] DOE should verify the findings of any bottom-up analysis against top-down studies that measure emissions with satellites or airplane flyovers. For instance, relying on data from aircraft, a 2018 study estimated the leakage rate in several shale

[4] Andrew Burnham, *Updated Natural Gas Pathways in GREET 2021*, at 5, Table 3, Argonne National Laboratory ("GREET 2021 NG Update") (Oct. 2021), https://greet.es.anl.gov/publication-update_ng_2021.

[5] *Id.*

[6] Ramón A. Alvarez et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, at 187, Table 1, Science (June 21, 2018) (accounting for a total of 12.72 Tg/year of methane emissions from production, gathering, processing, and transmission and storage) ("Alvarez 2018"), http://science.sciencemag.org/content/361/6398/186.

[7] *Id.*

[8] *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).

[9] *Id.* at 1.

[10] Susan Solomon et al., *Climate Change 2007: The Physical Science Basis,* at 142, IPCC (2007), https://www.ipcc.ch/site/assets/uploads/2018/05/ar4_wg1_full_report-1.pdf.

regions.[11] It found most had leakage rates well over the ~1% assumed in GREET: the estimated leakage rates were 5.4% in the Bakken, 3.2% in Eagle Ford East, 2.1% in the Denver Basin, 2.0% in Eagle Ford West, 1.5% in the Barnett, and 1.0% in the Haynesville shale region.[12] Similarly, a 2020 paper used satellite measurements to estimate that methane emissions were equivalent to 3.7% of gross gas extracted in the Permian Basin.[13]

In the short time since DOE issued the CHPS draft guidance, new studies have provided more evidence that the assumptions in GREET underestimate methane leakage in the gas supply chain. First, a recent study revealed that flaring is not as effective as previously assumed at controlling methane emissions in major U.S. shale regions. Previous estimates of emissions from oil and gas production assumed that flaring destroys methane with 98% efficiency, but measurements from the Permian, Bakken, and Eagle Ford regions indicate that flares effectively destroy only 91.1% of methane.[14] This is a significant source of methane emissions—constituting 4 to 10% of total U.S. oil and gas methane emissions—that has historically been underestimated.[15] Second, a study examined overflight data from the Permian Basin and found that methane emissions from natural gas gathering pipelines in that region are at least 14 times greater than EPA's national inventory estimates.[16] Since the update, GREET has assumed a gathering-line leakage rate that is about 13% greater than EPA's national inventory.[17] Consequently, the latest measurements from the Permian indicate that emissions from gathering lines in that basin are about 12 times greater than GREET currently assumes.

In addition to including accurate inputs for upstream methane leakage rates, GREET should incorporate the latest climate science on the global warming potential of methane. Specifically, DOE should use the global warming potential ("GWP") data from the latest IPCC report, which finds that methane of fossil origin has a 20-year GWP 82.5 times that of carbon dioxide and a 100-year GWP 29.8 times that of carbon dioxide.[18]

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[11] Jeff Peischl et al., *Quantifying Methane and Ethane Emissions to the Atmosphere From Central and Western U.S. Oil and Natural Gas Production Regions*, Journal of Geophysical Rsch.: Atmospheres (July 24, 2018), https://agupubs.onlinelibrary.wiley.com/doi/epdf/10.1029/2018JD028622.

[12] *Id.* at 7731, Table 1.

[13] Yuzhong Zhang et al., *Quantifying methane emissions from the largest oil-producing basin in the United States from space*, at 1, Science Advances (Apr. 22, 2020), https://www.science.org/doi/epdf/10.1126/sciadv.aaz5120.

[14] Genevieve Plant et al., *Inefficient and unlit natural gas flares both emit large quantities of methane*, at Table 1, Science 377, 1566-1571 (Sept. 2022), https://www.science.org/doi/10.1126/science.abq0385.

[15] *Id.*

[16] Erin Murphy & Jevan Yu, *Research shows gathering pipelines in the Permian Basin leaking 14 times more methane than officials estimate*, Environmental Defense 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/; Jevan Yu et al., *Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin*, at A, Env't Sci. & Technology Letters (Oct. 4, 2022), https://pubs.acs.org/doi/pdf/10.1021/acs.estlett.2c00380.

[17] GREET 2021 NG Update at 5, Table 3 (adjusting the assumptions for emissions from NG Production: Gathering and Boosting upward from 2,300 gigagrams to 2,600 gigagrams).

[18] Piers Forster et al., *The Earth's Energy Budget, Climate Feedbacks and Climate Sensitivity* in Climate Change 2021: The Physical Basis, at 1017, Table 7.15, IPCC (2021), https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter07.pdf.

Accurate accounting for upstream methane leakage is critical for the integrity of the CHPS, yet the current assumption that the leakage rate is ~1% is not supported by the peer-reviewed literature, which has found much higher rates of leakage when studies have not depended on industry opt-in. DOE should update GREET's assumptions regarding methane leakage to ensure that the hydrogen hub program does not inadvertently direct funding to producers that cannot truly meet whatever CHPS DOE adopts.

ii. Emissions from grid electricity.

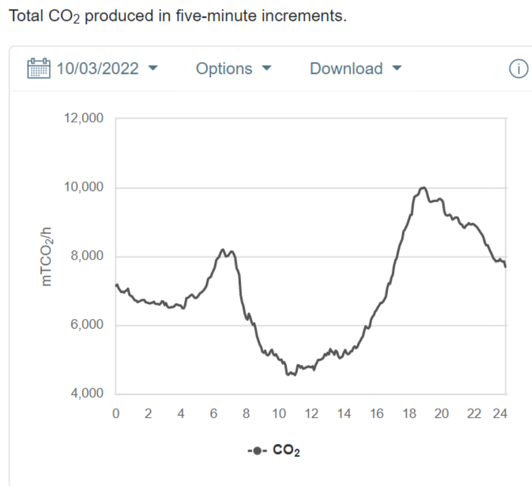
GREET's use of average efficiencies and emission factors leads to significant underestimations of the pollution impacts of adding new loads to the grid to power hydrogen production. The emissions intensity of a grid varies drastically over time, with relatively predictable daily and seasonal swings. Reliance on grid-average emissions data to estimate emissions from green hydrogen production is likely to systemically underestimate emissions because producers will have an incentive to use grid electricity during the times of day when fossil generators are the marginal unit and the grid emissions are higher than average. To correct this issue, DOE should update GREET so that the electric-sector emissions inputs are based on emissions from the marginal unit at the time the hydrogen producer is demanding grid electricity.

To illustrate the stark mismatch between grid-average emissions and the emissions impact of a hydrogen producer's load, consider the predictable business model of an electrolytic hydrogen producer in California. Electrolytic hydrogen producers in California are likely to co-locate their electrolyzers with solar generation resources.[19] These hydrogen producers may seek to increase the capacity factor of their electrolyzers by operating on grid power during the hours when their solar resources are producing little or no energy. Troublingly, the hours when these hydrogen producers have an economic incentive to rely on grid power are the hours when the California grid is the most emissions intensive. For instance, California Independent System Operator ("CAISO") data on the emissions-intensity of its grid on one recent day illustrates a typical daily pattern. Figure 1 shows the trend in CO_2 emissions on October 3, 2022, with dramatic swings over the course of the 24-hour day:[20]

[19] *See, e.g.*, Green Hydrogen Coalition, *HyBuild Los Angeles: Architecting the Green Hydrogen Ecosystem for a Deeply Carbonized LA*, at 3 (Sept. 20, 2022) (predicting the buildout of 26 GW of solar capacity to power California's green hydrogen economy), https://static1.squarespace.com/static/5e8961cdcbb9c05d73b3f9c4/t/6329cedaad25a149bd9e10e4/1663684316020/GHC_HyBuild_Phase_I_20220920.pdf.

[20] CAISO ISO, CO_2 emissions (serving ISO load) (graphic produced by selecting 10/03/2022 in the Total CO_2 trend tool), http://www.caiso.com/todaysoutlook/pages/emissions.html.

Figure 1: CAISO CO_2 Trend on October 3, 2022

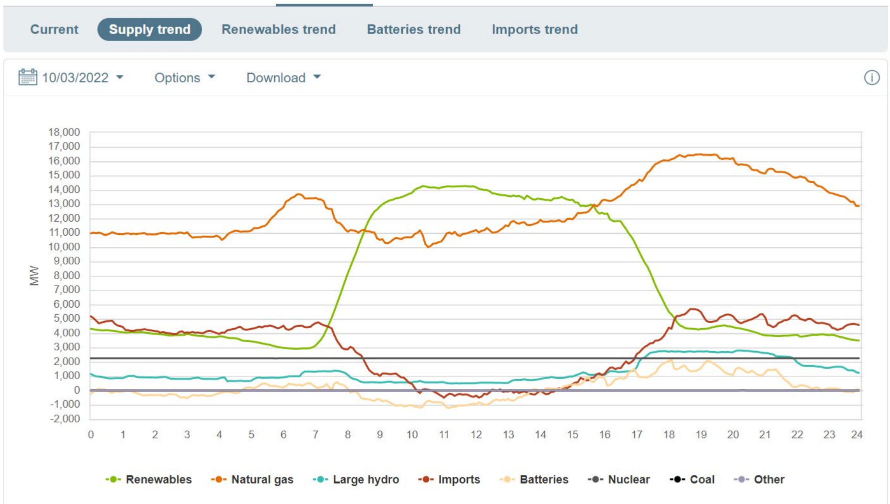


An electrolytic hydrogen producer would likely have an incentive to rely on on-site solar resources for energy during the time of day when those zero-emission resources produce the most energy (between 8 a.m. and 4 p.m.), and rely on grid resources to boost electrolyzer capacity factors during the other hours—when the CAISO grid energy is most polluting.

To make GREET more accurate, DOE should shift from relying on the average emissions of all grid resources to the emissions of the particular resources on the margin of a balancing authorities' economic dispatch. The emissions from running an electrolyzer on grid power are a function of the emissions from the marginal unit on the grid of the hydrogen producers' balancing authority during the time the electrolyzer demands electricity from the grid. The average emissions data will include data for zero-emissions resources that would have generated the same amount of electricity regardless of whether the electrolyzer load were on the grid, skewing the estimate for the emissions impact of the additional load. Again, CAISO data can illustrate the danger in relying on average emissions data, even if DOE were to improve GREET by including average emissions data for a particular hour. Figure 2 shows how much different types of generation resources contributed to CAISO's electricity supply in each hour of October 3, 2022:[21]

[21] CAISO, Supply trend (graphic produced by selecting 10/03/2022 in the Supply trend tool), http://www.caiso.com/todaysoutlook/pages/supply.html#section-supply-trend.

Figure 2: CAISO Supply Trend on October 3, 2022



In each hour of the day, the California grid supply includes over 2 GW of zero-emission nuclear energy. Using an average emissions figure that includes inflexible nuclear resources improperly suggests that these resources could ramp up to meet a proportionate share of the new load from hydrogen producers. In fact, new load during hours of minimal solar production is likely to be served by ramping up in-state gas-fired generators or increasing imports (largely from out-of-state gas-fired generators).

It is important that DOE improve the accuracy of GREET by incorporating data on the marginal resources in a hydrogen producer's balancing authority when the producer uses grid energy, and DOE can implement these improvements in a manner that is not overly burdensome. DOE could request data from each balancing authority on the marginal unit during each hour of the year for the most recent year that this data is available. Using this dataset, DOE could calculate the average emissions from adding a MWh of new load to that grid during each of the twenty-four hours in a day in a recent year (i.e., average marginal emissions at the hours starting at midnight, 1 a.m., 2 a.m., etc.). While this approach would fail to recognize seasonal and day-to-day variation, it represents a reasonable balance of precision and administrability.

iii. Short-lived climate forcers.

DOE should assess the emissions intensity of hydrogen production over both 20-year and 100-year time horizons to ensure that hydrogen hub funding does not cause dangerous spikes in emissions of short-lived climate forcers like methane. For instance, if DOE were to adopt 4.0 $kgCO_2e/kgH_2$ as the CHPS, it should only deem hydrogen as CHPS-compliant if its lifecycle emissions are no greater than 4.0 $kgCO_2e/kgH_2$ over both a 20- and 100-year period. Production pathways with high methane emissions will appear less carbon-intensive if DOE only considers 100-year GWPs because methane's 20-year GWP is about 2.5 times its 100-year GWP. If DOE ignores methane's short-term impacts on the climate, it risks funding hydrogen production activities that are inconsistent with the IPCC's recommendation to set "ambitious targets to reduce methane and other short-lived climate forcers."[22] Indeed, catalyzing a new methane-intensive hydrogen production industry could make it more difficult to reach the Biden Administration's climate goals, as the IPCC has found methane emissions must decline by about 33% by 2030 in pathways that limit warming to 1.5°C.[23]

Currently, the GREET model only estimates the carbon intensity of fuels over a 100-year timeframe. It would not be technically or administratively difficult to address this limitation in GREET, as the 20- and 100-year GWPs of climate pollutants are available from the IPCC.[24]

1.c. Are any key emission sources missing from Figure 1? If so, what are those sources? What are the carbon intensities for those sources? Please provide any available data, uncertainty estimates, and how data/measurements were taken or calculated.

DOE should clarify Figure 1 to ensure a full accounting of the carbon intensity of all hydrogen production methods. For instance, it is unclear whether Figure 1 excludes emissions associated with delivering methane to gas-fired power plants from its analysis of the lifecycle emissions of hydrogen production that relies on electricity to power a water- or methane-splitting process. Figure 1 properly includes emissions associated with methane delivery in the carbon accounting for hydrogen with fossil fuel feedstocks. It would be inaccurate to ignore these methane delivery emissions when producers rely on gas-fired power plants for electricity to power the hydrogen production process.

Further, DOE should clarify that the lifecycle analysis for all hydrogen production methods that rely on methane from fossil fuels will account for all fugitive emissions from production, gathering, processing, transmission, and storage. Each of these stages of the gas supply chain contributes significant emissions.[25] Clarifying the scope of the analysis will avoid industry arguments that sources not explicitly listed in Figure 1 (e.g., storage) should be excluded.

Finally, a rigorous carbon accounting for blue hydrogen must include the emissions impacts of using captured carbon for enhanced oil recovery ("EOR"). Thus, for hydrogen production pathways involving EOR, DOE should clarify that the "Potential emissions" that Figure 1 includes for the CO_2 sequestration stage include the emissions from burning petroleum produced through EOR.

1.d. Mitigating emissions downstream of the site of hydrogen production will require close monitoring of potential CO_2 leakage. What are best practices and technological gaps associated with long-term monitoring of CO_2 emissions from

[22] Franck Lecocq et al., *Mitigation and development pathways in the near-to mid-term* in Climate Change 2022: Mitigation of Climate Change, at PDF p. 41, IPCC (last visited Oct. 27, 2022), https://report.ipcc.ch/ar6wg3/pdf/IPCC_AR6_WGIII_FinalDraft_Chapter04.pdf.
[23] Keywan Riahi et al., *Mitigation Pathways Compatible with Long-Term Goals* in Climate Change 2022: Mitigation of Climate Change, at PDF p. 13, IPCC (last visited Oct. 27, 2022), https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_Chapter_03.pdf.
[24] Forster et al., *supra* note 18, at 1017, Table 7.15.
[25] Alvarez 2018 at 187, Table 1.

pipelines and storage facilities? What are the economic impacts of closer monitoring?

The costs of rigorously monitoring leakage of CO_2 at and downstream of the point of capture must be treated as core to the cost of any hydrogen production strategy that relies on CO_2 capture and sequestration. Importantly, leakage concerns are not limited to the GHG intensity of hydrogen production. Leaked CO_2 can contaminate groundwater or destroy aquatic or subsurface ecosystems by creating lethal concentrations for certain plants and animals.[26]

From a public health standpoint, CO_2 is not a benign gas. It is colorless, odorless, and denser than air. It is also an asphyxiant, and directly toxic at high concentrations.[27] Liquid CO_2 is a powerful cerebral dilator. At concentrations between 2 to 10%, it can cause nausea, dizziness, headache, mental confusion, and increased blood pressure and respiratory rate. Above 8%, nausea and vomiting appear. Above 10%, suffocation and death can occur within minutes.[28] CO_2 accidents kill 100 workers a year.[29]

In contrast to pipeline leaks of hydrocarbons, the lack of odor and invisibility of CO_2 means that it may not be possible for exposed parties to determine if they are in a hazard area before they are harmed, unless they have access to a CO_2 detection meter. A pipeline expert explained that "[o]nce a CO_2 pipeline release has been warmed by the surrounding environment, it travels unseen influenced by gravity, terrain, and the wind, preferentially settling in low spots, displacing air and providing no warning to persons and animals caught in the invisible release plume."[30] Conventional hydrocarbon releases can usually be detected by smell or sight.

Existing pipeline safety regulations do not address the risks of leaks from CO_2 pipelines, which are reported to have "terrifyingly large gaps on carbon dioxide pipelines."[31] The Pipeline Safety Trust found:[32]

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[26] IPCC, *IPCC Special Report on Carbon Dioxide Capture and Storage*, at 13 (2005) ("IPCC Special Report"), https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf.
[27] Permentier K, et al., *Carbon Dioxide Poisoning: A Literature Review of an Often Forgotten Cause of Intoxication in the Emergency Department*, at 1, Int'l J. Emergency Med. (2017) ("Carbon dioxide does not only cause asphyxiation by hypoxia but also acts as a toxicant. At high concentrations, it has been showed to cause unconsciousness almost instantaneously and respiratory arrest within 1 min"), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5380556/.
[28] Universal Industrial Gases, Inc., Material Safety Data Sheet: Liquid CO2, https://looksolutionsusa.com/wp-content/uploads/2015/08/co2_msds.pdf.
[29] Justine Calma, *Watch Out for a New Generation of Pipelines* (Aug. 26, 2021), https://www.theverge.com/2021/8/26/22642806/co2-pipeline-explosion-satartia-mississippi-carbon-capture.
[30] Richard Kuprewicz, *Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.*, at 1, 4, 8 (Mar. 23, 2022) ("Kuprewicz 2022"), https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf.
[31] Kuprewicz 2022. *See also* Richard Kuprewicz, Pipeline Lessons #1; https://www.youtube.com/watch?v=L5ikPFK0vvo.
[32] Pipeline Safety Trust, *CO_2 Pipelines – Dangerous and Under-Regulated* (Mar. 30, 2022), at 2, https://pstrust.org/wp-content/uploads/2022/03/CO2-Pipeline-Backgrounder-Final.pdf.

> The Pipeline and Hazardous Materials Safety Administration (PHMSA) currently exercises no jurisdiction over pipelines transporting CO_2 as a gas or liquid, and only regulates CO_2 pipelines with a concentration of more than 90% carbon dioxide compressed to a supercritical state, rendering any pipeline moving CO2 in any other state or with less than 90% purity entirely unregulated by the federal pipeline safety agency. **There are other large regulatory gaps around siting, fracture mitigation, determining potential impact areas, use of odorant, emergency response, and contaminants.** (emphasis added)

Impurities in the captured CO_2, including water and hydrogen sulfide (H_2S), can cause damage to pipelines, leading to dangerous leaks and explosions as the compressed fluid rapidly expands to a gas.[33] Further, water in the CO_2 stream can form carbonic acid in the pipeline, which is incredibly corrosive to carbon steel.[34] The U.S. DOT's PHMSA regulations do not limit water in CO_2 pipelines, an omission that could lead to accidents.[35]

CO_2 is currently usually shipped in pipelines in a supercritical state, which makes pipelines more susceptible to ductile fractures that "unzip" the steel and open great lengths of the pipeline.[36] A rupture in a high pressure CO_2 pipeline will eject CO_2 ". . . in a dense, powdery white cloud that sinks to the ground and is cold enough to make steel so brittle it can be smashed with a sledgehammer."[37] These extreme rupture forces throw tons of pipe, pipe shrapnel, and ground coverings, generating large craters along the failed pipeline. It is well known that CO_2 pipelines operating in dense phase, either supercritical or as a liquid, are particularly susceptible to such running ductile fractures.[38]

Leaked CO_2 remains in greater concentrations close to the ground. A terrifying CO_2 pipeline rupture and dense CO_2 plume release occurred in 2020, enveloping a Mississippi town. It traveled invisibly for miles, confounding the community and emergency personnel for hours about what was occurring and why people were becoming confused, having difficulty breathing, and collapsing. A full-scale evacuation of the town had to be carried out, which also impacted first responders and even caused automobiles to cease to function (further complicating evacuation). Community members reported breathing and cognitive impacts at least a year afterward.[39]

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[33] *Id.* at 4 ("Hydrogen sulfide, or H_2S, is mentioned here because of a supercritical state CO_2 pipeline rupture failure in Satartia, Mississippi in early 2020. First responders reported seeing a 'green cloud' from the pipeline release, which is a possible indication of high levels of H_2S. The Center for Disease Control has stated that H_2S levels of 300 ppm or higher are 'immediately dangerous to life or health'"); Resources for the Future, Carbon Capture and Storage 101 (May 2020), at 3, https://media.rff.org/documents/CCS_101.pdf.

[34] *Id.*

[35] *Id.*

[36] *Id.* at 3.

[37] Dan Zegart, *The Gassing of Satartia*, Huffington Post (Aug. 26, 2021), https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f.

[38] Kuprewicz 2022 at 6.

[39] Dan Zegart, *supra* note 37; Sarah Fowler, *'Foaming at the mouth': First responders describe scene after pipeline rupture, gas leak*, Clarion Ledger (Feb. 27, 2020), https://www.clarionledger.com/story/news/local/2020/02/27/yazoo-county-pipe-rupture-co-2-gas-leak-first-responders-rescues/4871726002/.

As a result of the severity of this accident, earlier this year PHMSA announced fining millions of dollars in penalties and determined that a new rulemaking will be needed for CO_2 pipeline safety[40] (though no date to begin is yet set).

According to the IPCC, "the effectiveness of the available risk management methods still needs to be demonstrated for use with CO_2 storage."[41] Furthermore, in the Mississippi pipeline rupture, the CO_2 plume traveled well outside the predicted impact area of the risk assessment, demonstrating the ineffectiveness of modeling in that case. The Pipeline Safety Trust found:[42]

> Traditional methods of determining Potential Impact Areas around hydrocarbon pipelines are inappropriate and insufficient for CO_2 lines, but that is exactly what the regulations call for. Denbury, the pipeline operator in Satartia, Mississippi, identified the area around its pipeline that could be impacted by a failure and many of the people hospitalized were outside of that identified area.

Moreover, model simulations of gradual CO_2 leakages from offshore storage in the ocean were found to trigger ocean acidification to a degree "significantly greater than pre-industrial variations in average ocean acidity."[43] Leakage can occur abruptly (through ruptures in pipelines or injection well failures) or gradually, often through undetected faults or fractures, and therefore requires long-term monitoring to enable constant and prompt response.

In light of the far-reaching uncertainties and enormous known risks associated with CO_2 leakage, we urge a moratorium on any new carbon capture infrastructure until PHMSA has been able to conduct a full review allowing for safety regulations. Even then, we urge the DOE to ensure that any hydrogen projects involving CO_2 capture and storage ("CCS") incorporate stringent setbacks between sensitive receptors (e.g., schools, hospitals, residential communities) and associated CO_2 transport and storage infrastructure. Finally, to protect communities and taxpayers, it is critical that the economic impacts of projects relying on CCS not only incorporate long-term monitoring, but also full liability for any resulting incidents, closure, clean-up, and remediation.

1.e. Atmospheric modeling simulations have estimated hydrogen's indirect climate warming impact (for example, see Paulot 2021). The estimating methods used are still in development, and efforts to improve data collection and better characterize leaks, releases, and mitigation options are ongoing. What types of data, modeling or verification methods could be employed to improve effective management of this indirect impact?

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[40] US DOT, PHMSA, PHMSA Announces New Safety Measure to Protect Americans from Carbon Dioxide Pipeline Failures after Satartia, MS Leak (May 26, 2022) ("To strengthen CO_2 pipeline safety, PHMSA is undertaking the following •initiating a new rulemaking to update standards for CO_2 pipelines, including requirements related to emergency preparedness, and response"), https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.
[41] IPCC Special Report at 13–14.
[42] Testimony of The Pipeline Safety Trust Presented by: Bill Caram, Executive Director before the California Air Resources Board (June 23, 2022), https://www.arb.ca.gov/lists/com-attach/2455-scopingplan2022-UyMHclciWFRQIgZj.pdf.
[43] *Id.* at 14.

DOE is right to consider hydrogen's indirect climate warming impact in developing the CHPS. Recent research shows that hydrogen's climate-warming potential is over 30 times larger than that of CO_2 in a 20-year time period and roughly 10 times larger over 100 years.[44] Hydrogen's propensity for leakage makes matters worse: research "suggests that hydrogen can leak 1.3 to 3 times faster than methane."[45] Despite hydrogen's substantial climate-warming potential, there is a shortage of empirical data on hydrogen emissions during the production and post-production process. The CHPS could help fill this important data gap by advancing development of better methods for measuring, monitoring, and controlling hydrogen emissions. Filling this data gap is essential because the failure to properly account for or control hydrogen emissions could offset any climate benefits of transitioning to hydrogen fuel.

We support Environmental Defense Fund's ("EDF") comments on this topic as reflected in its response to stakeholder feedback prompts 1(c), 1(e), and 2(a), and reiterate some of EDF's recommendations here.

First, DOE's lifecycle emissions analysis should include hydrogen emissions associated with both production and post-production processing, storage, and delivery as soon as emissions rates can be empirically assessed or reasonably estimated. This includes hydrogen emissions from leaking, venting, and/or purging.

Toward this end, DOE should encourage efforts to improve empirical data collection on hydrogen emissions during production and post-production. In particular, DOE should support the development of better methods for collecting site-level data on hydrogen emissions at commercial facilities. As EDF explains in its comments, component level emission factors can severely underestimate real-world emissions and therefore are not an adequate substitute for facility-level data collection.

DOE should also make clear to hydrogen hub applicants that they must budget for and employ systems to measure, report, and verify hydrogen emissions as well as systems to prevent, detect, and control hydrogen leaks as soon as those systems are commercially available. For larger hydrogen leaks that present safety risks, leak detection and control technologies are already commercially available and in operation at hydrogen production facilities, and thus should be required of all hydrogen hubs. For smaller hydrogen leaks that might not pose safety risks but *do* pose climate risks,[46] more precise sensors and faster leak detection technologies are

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[44] Ilissa B. Ocko & Steven P. Hamburg, *Climate consequences of hydrogen emissions*, at 9358–9359 Atmospheric Chemistry & Physics (July 20, 2022), https://acp.copernicus.org/articles/22/9349/2022/acp-22-9349-2022.pdf.

[45] *Id.* at 9355.

[46] *Id.* (explaining that there are "no commercially available [hydrogen gas] sensors that can detect hydrogen emissions at levels well below the threshold for hydrogen gas flammability") (citing Hiroaki Kobayashi et al., *Experiment of cryo-compressed (90-MPa) hydrogen leakage diffusion*, at 17928-17937, Int'l J. of Hydrogen Energy (Sept. 13, 2018), https://www.sciencedirect.com/science/article/abs/pii/S0360319918323693?via%3Dihub, and Alejandra H. Mejia et al., *Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure*,

already in development.[47] Hydrogen hubs should be required to employ these improved technologies as soon as they are commercially available. DOE should then incorporate empirical emissions data from these technologies into its lifecycle emissions analysis as soon as the data is collected and verified.

Finally, as discussed in our response to 1.b.iii., DOE's lifecycle emissions analysis should evaluate the emissions intensity of hydrogen over both 20-year and 100-year time horizons given hydrogen's short atmospheric lifetime.

1.f. How should the lifecycle standard within the CHPS be adapted to accommodate systems that utilize CO_2, such as synthetic fuels or other uses?

No comment.

2.a. The IPHE HPTF Working Paper (https://www.iphe.net/iphe-working-paper-methodology-doc-oct-2021) identifies various generally accepted ISO frameworks for LCA (14067, 14040, 14044, 14064, and 14064) and recommends inclusion of Scope 1, Scope 2 and partial Scope 3 emissions for GHG accounting of lifecycle emissions. What are the benefits and drawbacks to using these recommended frameworks in support of the CHPS? What other frameworks or accounting methods may prove useful?

No comment.

2.b. Use of some biogenic resources in hydrogen production, including waste products that would otherwise have been disposed of (e.g., municipal solid waste, animal waste), may under certain circumstances be calculated as having net zero or negative CO2 emissions, especially given scenarios wherein biogenic waste stream-derived materials and/or processes would have likely resulted in large GHG emissions if not used for hydrogen production. What frameworks, analytic tools, or data sources can be used to quantify emissions and sequestration associated with these resources in a way that is consistent with the lifecycle definition in the IRA?

i. DOE should not accept that capturable waste methane would be vented into the atmosphere as a baseline assumption.

The determination that certain kinds of biogenic energy are GHG neutral or negative rests on the flawed and distortionary assumption that the captured waste GHGs would otherwise be vented into the atmosphere *but for* the fuel (or in this case, hydrogen) production opportunity.

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at 8810-8826, Int'l Journal of Hydrogen Energy (Mar. 18, 2020), https://www.sciencedirect.com/science/article/abs/pii/S0360319919347275?via%3Dihub.

[47] *See, e.g.*, Zhiyuan Fan et al., *Hydrogen Leakage: A Potential Risk for the Hydrogen Economy*, at 8–11, Columbia University Ctr. on Glob. Energy Pol'y (July 5, 2022) (describing current research on various hydrogen leak detection technologies), https://www.energypolicy.columbia.edu/sites/default/files/pictures/Hydrogen%20Leakage%20Regulations,%20designed,%207.21.22.pdf.

Even for the *de minimus* amount of genuine waste methane that exists (equal to less than 1% of current fossil gas demand[48]), **this assumption 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. As a study by Dr. Emily Grubert notes, ". . . if the methane can be captured for [gas] 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 . . . Flaring destroys the methane with the same destructive benefit as combusting the methane productively."[49] Given that GHG emission reductions—methane in particular—are a clear policy priority for the Biden Administration, it follows that existing practice is not an appropriate baseline for determining emissions associated with these resources.

Therefore, DOE should assume as a baseline counterfactual that methane emissions are controlled—either through diversion to a flare[50] or improved waste management—rather than vented freely into the atmosphere. Furthermore, ensuring these resources are not improperly credited as carbon negative will prevent the confusion that mitigating the release of methane—however worthy a task—is the same as carbon removal and sequestration. The former merely mitigates the release of GHGs from an existing, anthropogenic source, while the latter removes GHGs already in the atmosphere, unlinked to any existing waste stream.

Worryingly, the distortion caused by crediting methane generation and capture as carbon removal can have grave consequences for communities, ecosystems, the climate, and in the case of livestock manure—small farmers. As Dr. Grubert describes, "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."[51] In California, large dairy Confined Animal Feeding Operations ("CAFOs") in the San Joaquin Valley are not only one of the largest sources of methane, but also the region's largest source of ozone air pollution and a significant source of nitrate groundwater pollution. Small or pasture-based farms do not produce manure methane—only the largest farms that utilize profit-maximizing practices of consolidation, confinement, and liquid manure handling create the enormous capturable methane that allows them to link to fuel production pathways.[52] As a result, rewarding the generation of methane from dairy farms has been found to disproportionately benefit the largest, most heavily-polluting CAFOs, perpetuating or even

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[48] Emily Grubert, *At scale, renewable natural gas systems could be climate intensive: the influence of methane feedstock and leakage rates*, at 6, Env't Rsch. Letters (Aug. 11, 2020) ("Grubert Article"), https://iopscience.iop.org/article/10.1088/1748-9326/ab9335/pdf.
[49] *Id.* at 5–6.
[50] *Id.* at 3 (when "the counterfactual is that waste methane would have been nonproductively burned in a flare," the resulting resource "is GHG negative…only if [the system's] total leakage is lower than leakage from the flare (1%), which is unlikely given that a best-guess estimate of downstream emissions alone is 0.8%.").
[51] *Id.* at 5.
[52] *See, e.g.*, Hyunok Lee & Daniel A. Sumner, *Dependence on policy revenue poses risks for investments in dairy digesters*, at 232 (Dec. 2018), https://calag.ucanr.edu/archive/?type=pdf&article=ca.2018a0037; Aaron Smith, *What's Worth More: A Cow's Milk or its Poop?*, UC Davis (Feb. 3, 2021), https://asmith.ucdavis.edu/news/cow-power-rising.

exacerbating their consolidation and corresponding local impacts.[53] To avoid perversely incentivizing pollution production, DOE should avoid GHG accounting frameworks that credit the capture of unregulated sources of methane pollution as carbon negative.

ii. DOE should avoid intentionally producing methane from biomass where none would otherwise occur.

Hydrogen production pathways that involve intentionally producing methane where none would have otherwise occurred (e.g., through gasification of biomass) are never carbon negative and are unlikely to ever be carbon neutral. Intentionally producing methane means that any methane leakage is GHG positive. Methane leakage levels observed in the existing, mature biogas industry (recently estimated to be double the International Energy Agency's official estimate[54]), would have significant adverse climate impacts, even if the biomass itself were assumed to be carbon neutral. Most logistically manageable and economically feasible sources of biomass to procure are not carbon neutral because genuine streams of municipal or agricultural waste are very small and widely dispersed.[55] The high capital and operating costs of biomass conversion facilities means that the only economically realistic way for these plants to operate is to run on purpose grown crops and large growth logging, which take between decades to more than a century, if ever, to recapture the carbon they emit when burned.[56]

iii. DOE should strictly limit funding for projects that rely on biogenic inputs due to the great uncertainty regarding their carbon intensity.

DOE should cap funding for projects that rely on biomass and biomethane to ensure that inaccurate carbon accounting for these projects does not undermine the overall success of the hydrogen hub program. Properly accounting for the climate impacts of biomass and biomethane is far more challenging than determining the carbon intensity of renewable electrolytic hydrogen. This is because carbon accounting for biogenic feedstocks involves complex counterfactuals about what would have happened to waste methane if it were not captured (for biomethane feedstocks), whether and when forest biomass will regrow (for woody biomass feedstocks), and what indirect land-use changes will result from using cropland to produce energy crops (for crop-based feedstocks). Consequently, experts that study the climate impacts of these feedstocks identify estimates with wide ranges of uncertainty.[57] The U.S. EPA for example, found in its

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[53] Amin Younes & Kevin Fingerman, *Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard*, at 18 (Sept. 2021), https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf.

[54] Semra Bakkaloglu et al., *Methane emissions along biomethane and biogas supply chains are underestimated*, at 726, Cell Press (June 17, 2022), https://spiral.imperial.ac.uk/bitstream/10044/1/97815/2/Bakkaloglu%20et%20al.2022.pdf.

[55] Iain Staffell et al., *The role of hydrogen and fuel cells in the global energy system*, at 477, Energy & Env't Sci. (2019) https://pubs.rsc.org/en/content/articlepdf/2019/ee/c8ee01157e.

[56] Center for Biological Diversity, *Forest Biomass Energy is a False Solution*, at 4 (last updated Mar. 2021), https://www.biologicaldiversity.org/programs/climate_law_institute/pdfs/Forest-Bioenergy-Briefing-Book.pdf.

[57] *See, e.g.*, Richard Plevin, *Uncertainty in estimating the climate effects of biofuels: EPA Workshop on Biofuel Greenhouse Gas Modeling* (Mar. 1, 2022), https://www.epa.gov/system/files/documents/2022-

review of the Renewable Fuel Standard that the program had led to the conversion of up to 8 million acres of land—nullifying and overwhelming any climate benefit the program might have had.[58] An updated 2022 study in the Proceedings of the National Academy of Sciences determined that corn ethanol had higher carbon intensity than gasoline.[59] It would be improper for DOE to rely on feedstocks with highly uncertain climate benefits for the hydrogen hubs to deliver transformational climate benefits.

iv. DOE should reject any calls to allow industry to rely on credit trading schemes to characterize fossil gas as biomethane.

DOE should also reject any schemes by project proponents seeking to produce hydrogen from fossil fuels but claim their hydrogen is renewable when purchasing "environmental attributes" from biogas producers. Such schemes reward and greenwash projects that use the same grey hydrogen technologies that are currently burdening communities with pollution without contributing innovation or scale to truly zero-emission hydrogen production technologies. DOE should heed the cautionary example of California's Low Carbon Fuel Standard program, which allows hydrogen producers to claim the environmental attributes of distant biogas supplies. Hydrogen producers have taken advantage of this opportunity to meet carbon goals by purchasing biogas credits rather than deploying renewable resources.[60] Perversely, hydrogen producers can maximize their incentive payments by coupling steam methane reformation ("SMR") of fossil gas with the purchase of out-of-state biogas attributes instead of deploying renewable generation resources and producing zero-emission electrolytic hydrogen.[61] Moreover, widespread reliance on offset and crediting schemes to treat fossil gas as if it were biomethane would be inconsistent with DOE's draft National Clean Hydrogen Strategy and Roadmap, which does not identify biomethane as a priority feedstock for clean hydrogen

03/biofuel-ghg-model-workshop-estimating-biofuel-climate-effects-2022-03-01.pdf; Miguel Brandao et al., *On quantifying sources of uncertainty in the carbon footprint of biofuels: crop/feedstock, LCA modelling approach, land-use change, and GHG metrics*, Biofuel Rsch. Journal (June 1, 2022) https://www.biofueljournal.com/article_148830_cfd95668b16943c4b53ed4b7e16977ce.pdf.

[58] EPA, *Biofuels and the Environment: Second Triennial Report to Congress*, at 39 (June 29, 2018), https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=IO&dirEntryId=341491.

[59] Tyler J. Lark et al., *Environmental outcomes of the US Renewable Fuel Standard*, at 3 (Feb. 14, 2022), https://doi.org/10.1073/pnas.2101084119.

[60] *See, e.g.*, John Eichman & Francisco Flores-Espino, *California Power-to-Gas and Power-to-Hydrogen Near-Term Business Case Evaluation*, at 59, National Renewable Energy Laboratory (Dec. 2016) ("Senate Bill 1505 in California requires that 33.3% of hydrogen produced for or dispensed by state-funded fueling stations must be made from eligible renewable resources. At present, the majority of the required renewable hydrogen is produced from SMR and coupled with the purchase of biogas credits."), https://www.nrel.gov/docs/fy17osti/67384.pdf.

[61] In the Low Carbon Fuel Standard ("LCFS") program, hydrogen producers can use book-and-claim accounting to treat fossil gas inputs as if it were biomethane, which allows companies that produce hydrogen from fossil fuels to treat their hydrogen as if it were carbon negative. Consequently, companies that produce hydrogen from fossil fuels can generate more tradeable LCFS credits than producers who make renewable electrolytic hydrogen, which has a carbon intensity of zero. Sasan Saadat & Sara Gersen, Reclaiming Hydrogen for a Renewable Future: Distinguishing Oil & Gas Industry Spin from Zero Emission Solutions, at slide 5, Earthjustice (June 20, 2022), https://efiling.energy.ca.gov/GetDocument.aspx?tn=243619.

production.[62] To ensure hydrogen funding is targeted toward scaling innovative production technologies that aid in tackling the climate crisis, we urge DOE to exclude allowance for conventional fossil hydrogen projects to rely on book-and-claim of attributes to lower their stated emissions.

2.c. How should GHG emissions be allocated to co-products from the hydrogen production process? For example, if a hydrogen producer valorizes steam, electricity, elemental carbon, or oxygen co-produced alongside hydrogen, how should emissions be allocated to the co-products (e.g., system expansion, energy-based approach, mass-based approach), and what is the basis for your recommendation?

No comment.

2.d. How should GHG emissions be allocated to hydrogen that is a by-product, such as in chlor-alkali production, petrochemical cracking, or other industrial processes? How is by-product hydrogen from these processes typically handled (e.g., venting, flaring, burning onsite for heat and power)?

No comment.

3.a. How should the GHG emissions of hydrogen commercial-scale deployments be verified in practice? What data and/or analysis tools should be used to assess whether a deployment demonstrably aids achievement of the CHPS?

No comment.

3.b. DOE-funded analyses routinely estimate regional fugitive emission rates from natural gas recovery and delivery. However, to utilize regional data, stakeholders would need to know the source of natural gas (i.e., region of the country) being used for each specific commercial-scale deployment. How can developers access information regarding the sources of natural gas being utilized in their deployments, to ascertain fugitive emission rates specific to their commercial-scale deployment?

No comment.

3.c. Should renewable energy credits, power purchase agreements, or other market structures be allowable in characterizing the intensity of electricity emissions for hydrogen production? Should any requirements be placed on these instruments if they are allowed to be accounted for as a source of clean electricity (e.g. restrictions on time of generation, time of use, or regional considerations)? What are the pros and cons of allowing different schemes? How should these instruments be structured (e.g. time of generation, time of use, or regional considerations) if they are allowed for use?

[62] *See* National Hydrogen Roadmap at 68 (assessing the potential availability of five renewable resources that could be used for clean hydrogen production, not including biomethane).

DOE should allow producers to use market structures to characterize the carbon-intensity of the electricity they use to the extent that the producers use these market structures to bring additional renewable resources online to provide power for their operations. However, allowing industry to base claims regarding the carbon intensity of hydrogen on unbundled renewable energy credit ("REC") purchases would significantly undermine the integrity of DOE's carbon accounting system.

It would be appropriate to allow producers to use power purchase agreements to claim that their electrolyzers are running on zero-emission electricity if:

1. The producer enters an agreement with a newly constructed wind or solar facility to purchase energy bundled with RECs;
2. The hydrogen producer timely retires the RECs and no other entity can claim the emissions benefits of the renewable energy;
3. The generator is either connected to the same balancing authority as the hydrogen producer or has an agreement to dynamically transfer electricity to the producer's balancing authority; and
4. The hydrogen producer uses the energy in the same hour that the electric generator delivers it to the grid.

Each of these requirements is essential for ensuring the integrity of any claim of using zero-emission electricity. The requirement to contract with new resources is the most straightforward way for entities claiming emissions benefits to demonstrate additionality. If hydrogen producers buy power from existing renewable resources, the customers who historically purchased the generator's power can shift to relying on fossil-fueled generators. This resource shuffling can defeat the purported benefits of using the renewable resource to power electrolysis.

The requirement to retire the RECs associated with the renewable energy is also essential to ensure additionality. Without retirement of the RECs, it would be easy for multiple entities to take credit for the same environmental benefits of the renewable energy. For instance, if a utility used the RECs to comply with a state renewable portfolio standard, the utility could avoid building new renewable resources that it would have otherwise deployed. In this scenario, the renewable resources that powered the electrolysis would provide little or no climate benefit because they would merely displace other renewables.

The requirements to deliver the renewable energy to the hydrogen producer's balancing authority in the same hour that the hydrogen is relying on grid power reflect the reality that the emissions impact of adding the producer's load to the electric grid depends on locational and temporal factors. That is, the emissions impact depends on the marginal unit that is dispatching in the producer's specific balancing authority at the specific time of the load. It would be inappropriate to credit a hydrogen producer for using renewable energy if the producer brings renewable generation online in a different region, displacing generation resources that are less emissions-intensive than the resources the hydrogen producer uses.

Allowing hydrogen producers to characterize their electricity as zero-emission based on the purchase of unbundled RECs could have devastating impacts on the climate. Grid-powered electrolysis could dramatically increase climate and criteria pollution, so DOE should avoid any policies that incentivize hydrogen producers to operate electrolyzers on grid electricity without bringing new zero-emission resources online to meet the new electric demand in real time. Even on a relatively clean grid like California's, the California Air Resources Board has determined that electrolytic hydrogen produced with grid-average electricity is a far more carbon-intensive fuel than diesel or compressed fossil gas.[63] And, as discussed in response to question 1b, estimates that rely on grid-average emissions likely underestimate the true harms of this hydrogen production with grid power. Thus, if hydrogen producers can characterize their hydrogen as zero-emission when it is produced from fossil-fueled grid electricity, they could seek lucrative taxpayer support to produce a fuel that is even more damaging to the climate than the fossil fuels currently in use.

If DOE allowed hydrogen producers to rely on unbundled RECs to characterize hydrogen produced from grid power as zero-emission, producers would see a powerful incentive to take advantage of this opportunity, even though unbundled RECs do not eliminate emissions from a facility's grid power. Unbundled RECs are so cheap that electricity users can pair them with dirty grid energy at a cost that represents a 1-2% premium on the price of electricity.[64] The climate benefits of these REC purchases are unsubstantiated. As a recent article in Nature Climate Change explained, a reported emissions reduction is "not real" when an electricity user purchases RECs that "do not lead to the generation of additional renewable energy."[65] In addition, "there is a risk of double counting the emission benefits of renewable energy generation" if one entity claims the benefits of specific zero-emission generation based on a REC purchase, while "other companies count that same renewable energy [based on] the grid average emission factor in their [region]."[66] It is crucial that DOE not allow hydrogen producers to use unbundled RECs to claim that their electricity is zero-emissions, as producers would have a strong incentive to characterize their electricity as renewable using questionable carbon accounting techniques instead of developing the resources necessary for truly zero-carbon hydrogen production.

3.d. What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0 $kgCO_2e/kgH_2$)?

DOE should not expect current hydrogen production operations to meet a clean hydrogen production standard. It would be unwise to encourage industry to retrofit existing SMR facilities, which constitute almost all the hydrogen production capacity in the United States today. Installing carbon capture at SMR facilities would create unnecessary stranded asset risk

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[63] California Air Resources Board, Table 7-1: Lookup Table for Gasoline and Diesel and Fuels that Substitute for Gasoline and Diesel (listing 164.46 gCO_2e/MJ as the carbon intensity of compressed hydrogen produced through electrolysis with California average grid electricity, 100.45 gCO_2e/MJ as the carbon intensity of diesel fuel in California, and 79.21 gCO_2e/MJ as the carbon intensity of compressed gas from average North American fossil gas), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut.pdf.

[64] Gautam Naik, *Problematic corporate purchases of clean energy credits threaten net zero goals*, S&P Global (May 5, 2021), https://www.spglobal.com/esg/insights/problematic-corporate-purchases-of-clean-energy-credits-threaten-net-zero-goals.

[65] Anders Bjorn, et al., *Renewable energy certificates threaten the integrity of corporate science-based targets*, at 540, Nature Climate Change (June 9, 2022), https://www.nature.com/articles/s41558-022-01379-5.

[66] *Id.* at 543.

without scaling the hydrogen production technologies that are necessary for deep decarbonization. Industry has not demonstrated that SMR is compatible with very high rates of carbon capture.[67] While it is unlikely that blue hydrogen will be able to compete with green hydrogen in the long-term,[68] fossil-based technologies like pyrolysis and autothermal reforming appear better suited for higher rates of carbon capture[69] and should be the targets of whatever limited funding DOE devotes to fossil technologies. Focusing scarce public resources on zero-emission hydrogen production technologies will best advance DOE's goal of "successful market adoption of clean hydrogen technologies in support of a net-zero economy by 2050."[70]

Moreover, communities that currently depend on the fossil fuel industry for jobs and tax revenue deserve economic diversification and a just transition to a prosperous, zero-carbon economy. Doubling down on fossil fuel investments in these communities, like installing CCS technology at SMR facilities, would only exacerbate their dependence on fossil fuels and their exposure to its boom-and-bust cycles.

DOE should not squander scarce resources on blue hydrogen—a technology that is not just less economically viable than green hydrogen but also more harmful to human health and the environment. While non-electrolytic production pathways may someday have a chance of being "low-carbon," studies show that even under the very strictest conditions, they would only approach the very worst-performing (i.e., most carbon-intensive) forms of green hydrogen production that exist today, and will never achieve close to zero GHG emissions.[71] Directing

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[67] The highest capture rate that has been demonstrated at a commercial facility is 90%, which was demonstrated at a coal-fired power plant, not SMR facility, and does not reflect long-term performance. Much lower capture rates have been reported from two coal plants, in the range of 55%-72%. Moreover, even a long-term 90% capture rate still falls short of the 95% capture rate that DOE estimates a facility would need to achieve to meet its proposed 4 $kgCO_2e/kgH_2$ standard. Robert W. Howarth & Mark Z. Jacobson, *How green is blue hydrogen?*, at 1680, Energy Sci. & Eng'g (July 26, 2021) ("Howarth & Jacobson"), https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956.

[68] Siri Hedreen, *Blue hydrogen runs 'significant risk' of becoming stranded asset – advisory firm*, S&P Global (July 19, 2022) (reporting on analysis by ISS ESG, a division of Institutional Shareholder Services Inc.), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/blue-hydrogen-runs-significant-risk-of-becoming-stranded-asset-8211-advisory-firm-71222790; David R. Baker & Josh Saul, *Manchin's Favorite Clean-Energy Plan Could be Obsolete Before it Starts*, Bloomberg (Nov. 10, 2021), https://www.bloomberg.com/news/articles/2021-11-10/manchin-s-favorite-clean-energy-plan-could-soon-be-obsolete. Assuming they are implemented with rigorous carbon accounting, the clean hydrogen production tax credits in the IRA will likely give a significant additional advantage to green hydrogen over blue hydrogen.

[69] Jan Gorski et al., *Carbon intensity of blue hydrogen production: Accounting for technology and upstream emissions*, at 1, Pembina Institute (Aug. 2021), https://www.pembina.org/reports/carbon-intensity-of-blue-hydrogen-revised.pdf.

[70] National Hydrogen Roadmap at 14.

[71] *See, e.g.*, Christian Bauer et al., *On the climate impacts of blue hydrogen production*, at 5 (Nov. 9, 2021) ("In order to be competitive with green hydrogen in terms of climate impacts over the long-term, blue hydrogen should exhibit a life cycle GHG footprint of not more than 2-4 kg CO_2- eq/kg. This is only possible with high CO_2 removal rates and methane emission rates below about 1% (GWP100) or 0.3% (GWP20)"), https://chemrxiv.org/engage/api-gateway/chemrxiv/assets/orp/resource/item/6141926f27d906e30288cff1/original/on-the-climate-impacts-of-blue-hydrogen-production.pdf; Howarth & Jacobson, at 1685 (finding that in a best-case scenario for

funding to hydrogen production pathways that cannot be scaled or achieve the zero emission-profile needed to achieve carbon neutrality will waste limited public support and risk locking in pollution.

4.a. Please provide any other information that DOE should consider related to this BIL provision if not already covered above.

Consistent with President Biden's campaign platform, the Biden Administration has repeatedly underscored the need for a bold program to tackle the climate crisis with an agenda that places racial, economic, and environmental justice at its core. We urge the DOE to keep these principals front of mind when determining how to design a "clean" hydrogen production standard. Through this lens, a standard that looks exclusively at carbon intensity while remaining agnostic to all non-GHG-related impacts of hydrogen production will not guarantee that the resulting hydrogen is "clean."

As noted in an October 2021 congressional 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."[72] This remains true even if biogenic feedstocks or carbon capture equipment are utilized to lower the carbon intensity of the hydrogen. In fact, the White House Environmental Justice Advisory Council specifically warned against support for CCS as an approach that will not benefit communities.[73]

Furthermore, DOE's review of hydrogen hub applications will need to consider health-harming emissions from both hydrogen production and use to ensure funding decisions comport with environmental justice principles. Some possible end-uses risk increasing NOx emissions in exchange for only minimal CO_2 emissions reductions. That outcome would harm communities, undermine the Biden Administration's stated commitment to environmental justice, and fail to secure the emissions reductions necessary to achieve deep decarbonization. Therefore, DOE should limit its hydrogen investments to eliminating emissions from industries that currently rely on fossil-derived hydrogen and decarbonizing hard-to-electrify sectors. This means DOE should **not** invest in blending hydrogen into the gas distribution system for residential and commercial heating and cooking, or burning hydrogen in power plants.[74] Similarly, while it is generally

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blue hydrogen in which producers rely on renewable electricity to drive the methane-splitting and carbon capture processes, the carbon emissions are still equivalent to 47% of the emissions from burning natural gas as a fuel, precluding a role for blue hydrogen in a carbon-free future).

[72] *Merkley, Raskin Lead Colleagues to Push Back on Dirty Hydrogen Energy in Climate Deal* (Oct. 27, 2021), https://www.merkley.senate.gov/news/press-releases/merkley-raskin-lead-colleagues-to-push-back-on-dirty-hydrogen-energy-in-climate-deal-2021.

[73] White House Environmental Justice Advisory Council, *Final Recommendations: Justice40, Climate and Economic Justice Screening Tool and Executive Order 12898 Revisions*, at 59, EPA (May 21, 2021), https://www.epa.gov/environmentaljustice/white-house-environmental-justice-advisory-council-final-recommendations.

[74] For further discussion of the hydrogen end-uses that DOE should prioritize—or reject—when making investments decisions, please see the March 21, 2022 response to DOE's RFI on the Regional Clean Hydrogen Hubs Implementation Strategy submitted by Center for Earth, Energy and Democracy,

unwise and wasteful to fund hydrogen transportation projects in sectors with electric alternatives, it would be especially harmful to use hydrogen vehicles in hubs that source hydrogen from production pathways that emit health-harming pollution.

To make good on the Biden administration's commitments to environmental justice, DOE must prevent the hydrogen hub program from perpetuating, exacerbating, or creating pollution burdens on communities that have historically suffered disproportionately the negative effects of fossil fuel development and use, including climate impacts. This translates to: (1) adopting a definition of "clean" that incorporates stringent limits on GHG as well as criteria and hazardous air pollutants ("HAPs"); (2) denying investments for hydrogen end-uses that would worsen local air pollution due to increased NOx or other emissions (3) establishing robust requirements for monitoring and disclosing GHG as well as criteria and HAP emissions up- and down-stream; and (4) modifying or rejecting proposed projects to address local residents' concerns.

Furthermore, DOE is obligated to seek input from environmental justice communities and organizations and ensure that environmental justice stakeholders have meaningful opportunities to provide input on the hubs well before DOE makes any decisions. DOE should ensure that environmental justice communities and their representatives receive notification about the hubs and have ample time to review materials about the options being considered. DOE should meet with representatives from all potentially affected environmental justice communities to solicit input in developing potential alternatives for the hubs, including but not limited to siting, production technologies, and mitigation measures. DOE must further include a complete environmental justice analysis in any decision document it releases.

To ensure that environmental justice and other stakeholders have meaningful opportunities to participate in the decision-making and implementation process at each step of the hydrogen hub program, DOE must, *at a minimum*, do all of the following:

(1) DOE must inform stakeholders, through direct outreach, that a hydrogen hub has been proposed for their community as soon as DOE commences consideration of the proposal.
(2) DOE must make all key documents regarding each phase of the proposal publicly available, including by posting all application and other materials online in a clearly identifiable and organized docket for each hub proposal that the DOE is reviewing. DOE should also establish a reasonable process for providing access to confidential information. FERC's process for allowing stakeholders to access critical energy infrastructure information pursuant to a non-disclosure agreement works reasonably well. Recognizing that project proponents have an incentive to improperly mark materials as confidential, DOE should allow stakeholders to challenge confidentiality designations.
(3) DOE must mandate that hub applicants include any plans for the utilization of eminent domain.

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(4) If the hub would be located in or near a community with a significant population of non-English speakers, DOE must provide copies of all key documents that are translated into the appropriate language(s).
(5) DOE must provide instructions on how and by when to comment on the proposal/application or other key documents.
(6) DOE must provide adequate time to comment on the proposal/key documents.
(7) DOE must conduct early outreach to any interested or affected tribal governments or Indigenous communities to engage in the consultation process required by DOE Order 144.1 and subsequent updates.

Conclusion

We urge DOE to adopt a more stringent CHPS and focus investments of taxpayer funds on the zero-emission hydrogen production technologies that can play a meaningful role in meeting the Biden Administration's 2050 carbon goals and avoiding the most catastrophic impacts of climate change. If DOE adopts a loose standard of 4 $kgCO_2e/kgH_2$ produced, it will be especially important for industry to demonstrate compliance with that standard through rigorous carbon accounting. We further urge DOE to make good on the Biden Administration's commitment to environmental justice by ensuring that the DOE meaningfully engages with environmental justice communities and that the hydrogen hubs do not perpetuate, exacerbate, or create pollution burdens in communities that have disproportionately suffered the negative effects of fossil fuel development and use.

Respectfully submitted,

350 New Mexico (New Mexico)

California Environmental Justice Alliance (California)

Center for Biological Diversity (National)

Communities for a Better Environment (California)

Earthjustice (National)

Greenlining Institute (California)

New York City Environmental Justice Alliance (New York)

San Juan Citizens Alliance (Colorado and New Mexico)

Sierra Club (National)

Western Environmental Law Center (Arizona, Colorado, Oregon, Montana, New Mexico, and Washington)