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United States Department of Energy
1000 Independence Ave SW
Washington, D.C., 20585

November 14, 2022

Re: United States Department of Energy Clean Hydrogen Production Standard Draft Guidance

Dear Secretary Granholm:

Through its Clean Hydrogen Production Standard (CHPS), the Infrastructure Investment and Jobs Act of 2021 (IIJA) calls for the creation of a framework for defining "clean hydrogen" with goals of reducing emissions from hydrogen production while supporting the growth of the nascent industry. The CHPS will be central to U.S. states' development of Regional Clean Hydrogen Hub (Hub) proposals and DOE's selection of which types of projects will receive up to $8 billion in combined research and development funding.

The proposed guidance notes that while CHPS is not a regulatory standard, Hubs funded in support of the IIJA "will be required to 'demonstrably aid the achievement' of the CHPS by mitigating emissions across the supply chain to the greatest extent possible." These comments focus on emissions accounting for green electrolytic hydrogen, which our analysis indicates is likely the most economical, scalable, and promising form of zero-carbon hydrogen, and the most heavily subsidized by the Inflation Reduction Act.

In our assessment of electrolytic hydrogen, it is clear that certain regulatory guidelines risk *worsening* greenhouse gas (GHG) emissions while failing to advance a longer-term trend toward low-carbon hydrogen production. However, more rigorous standards can support both immediate GHG emissions reductions as well as the development of a robust accounting framework that can help scale the clean hydrogen production industry.

The stakes are much higher with the advent of the Inflation Reduction Act of 2022 (IRA) and its Section 45V Clean Hydrogen Production Tax Credit, which accelerated the economic viability of low-carbon hydrogen electrolysis. The U.S. Treasury may look to the CHPS in designing its tax guidance for the Section 45V tax credits, amplifying the standard's GHG emissions implications. And because the hydrogen hubs DOE funds will likely be the country's first large-scale demonstration projects, sound parameters that demonstrate successful emissions accounting for the industry are crucial before green hydrogen scales.

These comments are intended to help the U.S. Department of Energy improve its CHPS guidance to ensure it succeeds in reducing GHG emissions while helping grow the nascent clean hydrogen industry.

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Part 1 – Data and values for carbon intensity of electricity consumed by electrolyzers

Request being addressed: Requests 1a and 1b. Specifically:

- **Request 1a** seeks comment on assumptions made for key parameters that can influence the lifecycle emissions of hydrogen production. The provided spreadsheet notes that the "use of predominantly clean energy (i.e. >=85% clean energy, <=15% U.S. grid mix) in electrolysis is expected to enable achievement of the lifecycle target proposed in this draft guidance" and asks for feedback on "the technical and economic feasibility of electrolyzers accessing this share of clean energy."
- **Request 1b** asks to comment on the accuracy of estimates of carbon intensity for parameters that are not likely to vary widely by deployments in the same region of the country, including the carbon intensity of regional grids using the GREET tool. It also asks for comments regarding other reasonable values for these estimates and the uncertainty ranges associated with these estimates.

We address these questions together, acknowledging that thematically they are addressing methods to determine values for the carbon intensity of electricity (e.g. per MWh) as an input to determining the emissions intensity of electrolytic hydrogen.

Recommendation: DOE should produce a consistent method to evaluate the electrolyzer production efficiency (kg H_2/MWh throughput across technologies and hydrogen production setups.

One key parameter that influences the lifecycle emissions of hydrogen production is the electrolytic efficiency. At 100% efficiency (high heating value) a MWh of electricity will produce 25.4 kg of hydrogen[1]. In electrolysis, most life-cycle emissions can be tied to the life-cycle emissions of the input power, so electrolytic efficiency is a key parameter in lifecycle emissions. Take for example a mix at 85% clean (zero emissions per MWh) and 15% U.S. grid mix (2020 value is 386 kg CO_2/MWh according to EIA[2]) – at 100% efficiency life-emissions from input power would be (.15 x 386 /25.4) = 2.28 kg CO_2/kg H_2. At 75% efficiency the figure would be 3.04 kg CO_2/kg H_2.

It may be that extra electricity is necessary to compress hydrogen for delivery. Some electrolyzers produce hydrogen at pressures around 600 PSI[3], directly suitable for many storage and transportation uses, while others may produce hydrogen gas at lower pressures and may require additional electricity for pumps. Additional electricity loads might be necessary for water purification. Total electricity inputs and associated emissions should be rolled up into a single consistent kg H_2 per MWh throughput parameter to determine the emissions intensity of the hydrogen production, as well as commercial viability.

Recommendation: GREET average emissions intensities should not be used as an input to determine electricity input emissions to produce electrolytic hydrogen. Instead, DOE's CHPS should follow the principles in "Part 2" of these comments to verify the use of clean electricity until better emissions impacts and offsets methodology can be developed. In the meantime, DOE should require electrolytic hydrogen producers to use hourly time-matching to improve emissions estimates of drawing power from the grid; specifically, use emissions profiles of

[1] See pp5-8 in "Hydrogen Production: Fundamentals and Case Study Summaries," NREL, https://www.nrel.gov/docs/fy10osti/47302.pdf.

[2] https://www.eia.gov/tools/faqs/faq.php?id=74&t=11

[3] PlugPower product brochure for 4250D unit specifies output at 580 psig, https://www.plugpower.com/wp-content/uploads/2021/10/EX-4250D_F041122.pdf, about the right order of magnitude for pipelines.

specific units under contract to supply power and move from GREET's region-specific average grid mixes to estimates of the marginal power generator likely to ramp up in a given hour and, eventually, to a more rigorous marginal emissions accounting framework.

As explained more fully in Part 2 below, using annual or time-specific average intensity of a regional grid is an inaccurate method for determining the emissions intensity of input cited here. What matters are marginal emissions – the emissions resulting from increased electricity consumption. In general, dispatchable resources , primarily natural gas and coal, are today the most likely to ramp up to serve electrolyzers' added loads (all else equal) in grids where these resources exist, so their emission intensities may need to be weighted more heavily than the average grid mix. For example, just knowing that the annual generation mix of a given grid is 85% clean, 15% fossil is not sufficient to show emissions intensity of incremental hydrogen production with confidence. We would need to know the specific emissions intensity of the remaining 15% fossil (unabated coal, gas, or other), as well as how the marginal fuel matched with hydrogen use. In fact, electricity systems and prices are so complex, a counterfactual is likely needed, which asks – "What would the grid emissions be in the absence of the incremental hydrogen load?" Incremental demand should be attributed to incremental supply.

DOE should use the IIJA funding for electrolytic hydrogen to begin working on accurate marginal emissions accounting, while at the same time demonstrating the feasibility of emissions accounting through bilateral contracting under the principles of additionality, time-matching, and regionality expounded in Part 2 below. Ultimately, the ideal measure is a method by which DOE can verify the marginal emissions incurred by drawing power from the grid. The regional grid operators (such as PJM[4]) and EPA's AVERT tool[5] each have promising frameworks from which DOE can start and test through the hubs as well. DOE should encourage the creation of systems that could gather this data, as it would be the highest-fidelity measure for lifecycle emissions and may support a range of other emissions tracking schemes (e.g., federal government's 24/7 carbon free electricity goals).

[4] https://dataminer2.pjm.com/feed/fivemin_marginal_emissions/definition
[5] https://www.epa.gov/avert/how-avert-works

Part 2 – Opportunities and risks in emissions intensity guidance for hydrogen produced from grid-connected electrolyzers

Request being addressed: Request 3c. Specifically:

- Should renewable energy credits (RECs), power purchase agreements (PPAs), 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?

Central to the CHPS design is the ability to accurately measure and verify lifecycle GHG emissions from hydrogen production. This set of recommendations is intended to support the creation of an accounting methodology for determining lifecycle GHG emissions associated with electrolytic hydrogen. Such a methodology should support the growth of low-carbon hydrogen from electrolysis **without** inadvertently increasing net GHG emissions beyond the limits specified by CHPS and **without** subsidizing the production of such emissions-intensive hydrogen.

Recommendation summary:

1. **Tying electrolyzer operations to actual emissions impacts:** Any emissions accounting methodology developed for electrolysis should ultimately tie back to the impact on net lifecycle GHG emissions.
2. **Verifying the source of fossil electricity:** Until data and methods are available for a more complete system-wide emissions-based accounting framework, a simpler accounting scheme that directly tracks and validates zero-carbon and carbon-intensive electricity used in electrolysis should be implemented as a proxy, adhering to strict requirements to demonstrate additionality, time-matching, and regionality for the zero-carbon electricity.
3. **Avoiding loose standards:** The current lack of a marginal emissions accounting framework shouldn't open the door to tracking methodologies with loose causal connections between electricity production and use and that are ignorant of broader emissions impacts on the grid, such as offsetting the use of grid power with renewable energy credits.
4. **Allowing a range of business models to participate:** While electrolyzers exclusively connected to new clean electricity resources clearly meet the zero-emissions standard, electrolyzers should be allowed to source electricity from the grid so long as the DOE has developed robust, effective standards that adhere to the requirements of additionality, time-matching, and regionality described in Recommendation 2.
5. **Properly accounting for some grid emissions:** Since the IIJA CHPS and IRA 45V clean hydrogen production tax credit framework of up to 4kgCO_2e/kgH_2 allow for some level of GHG emissions, electrolyzers should be permitted to draw some grid power, preferably with an identified source supplier but otherwise with an estimated emissions impact. However, the use of any grid or fossil power should entail an additional requirement of averaging annual emissions for the purposes of determining compliance with the CHPS and 45V.

6. **Preventing gaming of tax credits for perverse outcomes:** The CHPS and deployment of hydrogen hubs should promote industry standards that block the combined use of the IRA's 45V and 45Y tax credits for perverse outcomes at odds with the language of and intention behind the IIJA and IRA. Any IIJA hydrogen hubs should demonstrate, through a robust CHPS, how to prevent hydrogen produced from electrolysis from immediate reuse as fuel for electricity.

RECOMMENDATION 1 – TYING ELECTROLYZER OPERATIONS TO ACTUAL EMISSIONS IMPACTS

Recommendation: Any emissions accounting methodology developed for electrolysis should ultimately tie back to the impact on net lifecycle GHG emissions.

The primary purpose of the CHPS is to support the production of hydrogen achieving a carbon intensity of 2 $kgCO_2e/kgH_2$ or less at the point of production, accounting for technological and economic feasibility.[6] In matching the IRA's definition of qualified clean hydrogen, the draft CHPS guidance proposes a lifecycle GHG emissions intensity of 4 $kgCO_2e/kgH_2$ or less. The adoption of a lifecycle-based standard is wise, as electrolyzers do not emit GHGs directly but can be responsible for substantial upstream emissions depending on the emissions impacts of electricity sourcing and hydrogen leakage.

The CHPS can only be effective in stimulating and providing a model for low-carbon hydrogen production if it delivers confidence and transparency around the lifecycle emissions of hydrogen production. One way for electrolytic hydrogen to prove its emissions clearly is to self-supply clean electricity by co-locating and directly linking clean generation and hydrogen production without a grid interconnection. This accounting is relatively straightforward, but we believe there are significant benefits and clear statutory support to allow grid-connected hydrogen production to qualify for Hub funding and 45V tax credits. For grid-connected electrolytic hydrogen production, meeting the CHPS requires proving that upstream GHG emissions incurred by electrolysis are accurately accounted for and, to the extent they exceed the CHPS standard, offset by reductions in electric generation emissions elsewhere on the grid, through new clean electricity production.

Average emissions intensity of the grid at the time of consumption, let alone an annual average, is not always an accurate measure of the GHG emissions impact of additional electricity consumption, making it an inaccurate way to measure the GHG impacts of hydrogen electrolysis. What matters is marginal emissions – what power plants increased production in response to increased consumption. For example, if half the grid mix is clean energy, and the other half is gas, the grid mix average emissions intensity would be half that of gas. However, if the clean energy is also running at full capacity and gas is used to meet new load, the marginal emissions would be the same as a full gas-fired power plant. Because of the complexity of electricity systems, figuring out the precise marginal emissions impact of new load is an immensely complex counterfactual—what would have happened if load hadn't changed? Firms such as Watt Time provide a strong summary of the academic literature on the state of the art solutions emerging to solve this problem.[7] To date, only one independent system operator, PJM, has started to provide some of this locational marginal emissions information.[8]

Eventually ways to track marginal emissions impacts in a highly precise manner will become more available. With this information, in theory, a developer whose electrolyzer uses grid power could track the marginal emissions rate of the point on the power grid where hydrogen is produced—that is, figure out which power

[6] IIJA p.587: https://www.congress.gov/117/plaws/publ58/PLAW-117publ58.pdf.
[7] https://www.watttime.org/app/uploads/2022/10/WattTime-MOER-modeling-20221004.pdf.
[8] https://dataminer2.pjm.com/feed/fivemin_marginal_emissions/definition.

plants needed to ramp up to serve the electrolyzer's added load. The developer could then build **new additional** clean electricity resources elsewhere on the grid and track the relevant marginal emissions rates of their locations, figuring out the emissions intensities of the power generation they displaced. If the GHG emissions caused by electrolysis are sufficiently offset by GHG reductions elsewhere on a periodic timescale, the developer could prove its electrolysis has satisfied the CHPS.[9]

However, we currently lack the data and systems necessary to verify the GHG emissions impacts of these actions, and integrating them into CHPS and 45V in a matter of months would be infeasible—we need a method that allows the Hubs to get started now. More precise marginal emissions accounting may be developed over time and could be part of a worthwhile green hydrogen Hub proposal. In time this methodology would be appropriate for determining electrolyzed hydrogen's lifecycle GHG emissions. But in the meantime, Congressional intent to support clean hydrogen production is better served by adopting more stringent rules for estimating the emissions impact of electrolytic hydrogen (as discussed in Recommendation 2) than by allowing loose, unproven, or mismatched accounting frameworks that risk substantially increasing GHG emissions (as discussed in Recommendation 3).

RECOMMENDATION 2 – VERIFYING THE SOURCE OF CLEAN AND DIRTY ELECTRICITY

Recommendation: Until data and methods are available for a more complete system-wide emissions-based accounting framework, a simpler accounting scheme that directly tracks and validates zero-carbon and carbon-intensive electricity used in electrolysis should be implemented as a proxy, adhering to strict requirements to demonstrate additionality, time-matching, and regionality for the zero-carbon electricity.

In the absence of a marginal emissions matching methodology, the hourly tracking and matching of electricity procurement and consumption in specific sources and sinks can be used as a proxy. Without strict boundaries, the upstream life-cycle emissions from electricity purchasing can become impossible to accurately estimate. Basically, we ask that electrolyzers accurately indicate where exactly the power is coming from that produces hydrogen so that emissions impacts can be computed in the absence of comprehensive grid-wide emissions impacts and offsets accounting scheme.

For the dirty fraction, electricity source to sink accounting could be done with a physical bilateral contract, tolling agreement, or other financial arrangement. Some leeway maybe necessary for real-time operations (see Recommendation 5).

For the clean fraction a little more work is necessary. Namely, clean electricity-based accounting systems must adhere to at least three restrictions to ensure the validity of their claimed lifecycle GHG emissions impacts: additionality, regionality, and time-matching. The following descriptions of these principles are intended to demonstrate that they are **necessary** in defining a CHPS for electrolytic hydrogen production and that compliance with them is **possible.**

[9] For more detail on marginal emissions accounting, see page 17 of these comments to the Treasury from RMI et al.: https://www.regulations.gov/comment/IRS-2022-0023-1881.

Additionality: Electrolyzers claiming to use clean electricity must source such power from **new** projects built for the primary purpose of supplying power to said electrolyzers.[10] The additionality criterion is the most important of the three for achieving GHG emissions reductions and the easiest with which to ensure compliance.

Compliance is necessary: If an electrolyzer draws power from clean electricity already built to serve other purposes, fossil fuel power plants are the most likely source of power to step in to meet the demand no longer served by the diverted clean electricity.

In general, renewable energy and nuclear power facilities send power to the grid whenever they are available, since renewable energy sources like wind and solar cost next to nothing to run and since nuclear power has low variable production costs and is typically inflexible. While zero-carbon energy sources like hydropower and geothermal may have some ability to increase output in response to new demand, they tend to be the next-cheapest resources in terms of marginal costs and often are running at full capacity. This leaves fossil fuel power plants as the resources that most often step in to serve new load or replace lost generation (such as diverted clean electricity). This in turn incurs new GHG emissions, as it is essentially equivalent to the electrolyzer being powered by fossil fuels.

Additionality requires that any electrolyzer collecting tax credits or any other government subsidy for clean hydrogen production must keep and retire sufficient RECs generated by the clean electricity project from which it is sourcing zero-carbon power to cover its consumption; otherwise, double-counting of clean attributes would ensue, invalidating additionality. As discussed under Recommendation 3, the additionality criterion remains necessary even when building in a state that has a binding renewable portfolio standard (RPS).

Compliance is possible: The additionality criterion can be met straightforwardly by building new, dedicated, co-located clean electricity projects to serve electrolyzers. Additionality becomes harder to measure via long-term contracts that rely on the bulk power system to connect demand and supply, but still possible. For example, lack of clarity can come when clean electricity projects would be economically viable without the additional hydrogen electrolysis load (i.e., it would have been built anyway), or when the electrolyzer subscribes to only part of the project (i.e., hydrogen was not the primary purpose). When the electrolyzer is the primary off-taker with a long-term contract that takes on substantial financial risk for the new generator, there should be a rebuttable presumption of additionality. As a baseline, hydrogen projects seeking credit for megawatt-hours (MWh) from specific projects and their associated emissions intensities should be required to affirmatively demonstrate additionality.

Regionality: Electrolyzers and their dedicated clean electricity resources must be located on the same interconnection and **near each other,** or at least account for the impacts of any electrical separation. The regionality criterion is the next most important of the three for achieving GHG emissions reductions—at least under an electricity-based proxy scheme as opposed to a marginal emissions accounting framework—and easier to ensure compliance when projects are closer in proximity to each other.

[10] We recognize that "newness" and "primary purpose" are not precise concepts, and we implore DOE to work to define them as part of the CHPS and to inform 45V compliance as well. Renewable projects built and co-located to provide dedicated supply to an off-grid hydrogen electrolyzer are the gold standard that virtually ensures newness, primary purpose, and therefore additionality. Any divergence from this model should relate back to it—how much less sure are we that the clean electricity project and its generation are additional?

Compliance is necessary: Consider the consequences of three different categories of electrical separation.

- For **long-distance** electrical separation (e.g., different regional transmission organizations), an electrolyzer located in a relatively dirty part of the U.S. power grid will incur more GHG emissions than a clean electricity resource located in a relatively clean part of the power grid will displace.
- For **mid-distance** electrical separation (e.g., different zones within a regional transmission organization), the relative locations of these assets may worsen congestion, such as if a new wind farm is built in an export-congested zone and an electrolyzer is built in an import-congested zone (e.g., upstate New York vs. New York City). This could result in renewable curtailment, energy losses (e.g., if a storage asset must cycle to help relieve congestion), or increased fossil fuel power generation in the electrolyzer's zone—all of which incur net GHG emissions.
- For **close-distance** electrical separation (e.g., same zones within a regional transmission organization or in the same balancing authority), emissions impacts are clearer, but transmission and delivery losses still play a role (as they also do for mid- and long-distance separations). For example, if a clean electricity resource generates 100 MWh of power and an electrolyzer uses 100 MWh of power, the electrolyzer's input may only consist of 95 MWh of clean electricity after accounting for transmission losses, with the remaining 5 MWh coming from generic grid power (with associated GHG emissions).[11] If generic grid power corresponds to, say, 20kg CO_2e/kg H_2, even a 5% effect would correspond to a real world upstream impact of 1kg CO_2e/kg H_2—more than enough to make the most attractive 45V tax credit value unachievable unless extra clean generation is procured.

Compliance is possible: The regionality criterion may be met by requiring electrolyzer and clean electricity resource pairings to be located in the same RTO zone, grid node, or utility service territory **and** requiring some accounting of transmission losses through transmission loss matrices or transmission delivery factors.[12] The former restriction can be gradually lifted if there are rigorous ways to offset impacts from interzonal congestion or the varying makeups of different grid regions.

<u>Time-matching</u>: Electrolyzers must operate during the **same time intervals** when their dedicated clean electricity resources are generating power, on a MWh per MWh basis. Time-matching is becoming more significant as the U.S. power grid integrates more solar and wind resources and the marginal avoided emissions and market value of additional wind and solar generation decreases.[13] It is also the toughest principle for verifying compliance, but a great deal of work is underway to establish the needed accounting systems in the near future.

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[11] The U.S. Energy Information Administration (EIA) estimates that electricity transmission and distribution (T&D) losses equaled about 5% of the electricity transmitted and distributed in the United States in 2016 through 2020: https://www.eia.gov/tools/faqs/faq.php?id=105&t=3.

[12] For an example of how to account for marginal system transmission losses tied to a given source, see NYISO's methodology: https://www.nyiso.com/documents/20142/25467833/LBMP-Loss-Price-Component.pdf/d882794e-619a-2181-d367-475ab0fdf897.

[13] For example, in a given region, solar resources all exhibit the same daily generation shapes (with cloud cover smoothed across the resource base). After a certain penetration level, adding new solar resources does much less to decarbonize the grid than adding other clean resources to help decarbonize hours when solar resources are offline, such as batteries to shift solar generation to evening hours or "clean firm" resources like geothermal.

Compliance is necessary: If an electrolyzer draws power from the grid during periods when higher-emitting generation (e.g., coal) is marginal while the clean electricity resource sends power to the grid during periods when lower emitting generation (e.g., natural gas or batteries) are marginal, the electrolyzer will incur more GHG emissions than the clean electricity resource displaces. Time-matching the use of an electrolyzer with the production of new clean electricity helps ensure minimal to no net GHG impacts. Hourly accounting is likely the longest appropriate interval for time-matching, balancing the need for temporal granularity (e.g., to capture diurnal trends in power generation from different resources) with the needs for simplicity and feasibility.

Compliance is possible: The time-matching criterion is the most difficult with which to verify compliance when electrolyzers are consuming grid power. For self-consumption, time-matching occurs by definition. For grid power consumption, verification bodies like M-RETS[14] and large corporate offtakers like Google[15] are working to develop hourly accounting systems, and some method will be necessary to demonstrate compliance with President Biden's executive order for the federal government to meet 50% of its demand with hourly-matched clean electricity by 2030.[16]

In the European context, some industry groups have argued against hourly matching as too onerous due to the need to keep electrolyzers running at high load factors,[17] but in the U.S. context, there are two factors that argue against this. First, the 45V tax credits for electrolysis powered by variable clean power are rich enough to allow commercial viability of electrolysis-derived hydrogen at lower load factors. Second, variable clean power in the U.S. has higher capacity factors than in Europe, allowing greater availability (especially with a modest amount of over-procurement).

These principles of additionality, regionality, and time-matching are not new. They are at the heart of existing concerns around the legitimacy of emission reduction claims that rely on voluntary corporate carbon offset and clean energy purchases.[18] Through the CHPS, DOE and Treasury have an opportunity to institutionalize practices that set a standard for emissions accounting that can influence and set a positive example for corporations and other countries, or perpetuate the mistakes of private industry that undermine public confidence.

Emissions accounting is especially important to get right for DOE-funded pilot projects to demonstrate the feasibility of a nascent carbon-reducing industry like electrolytic hydrogen production, which the U.S. and many other countries recognize will play a growing role in decarbonizing the economy. As it will take some time for electrolyzers to begin scaling up deployment, there is an opportunity to put proper accounting methods in place and hold electrolytic clean hydrogen production to these standards from the beginning, helping to ensure 45V hydrogen production tax credits can achieve their intended effect of reducing emissions as the industry scales. Since Hubs are primarily research and development projects intended to cultivate robust, high-fidelity low-carbon production processes and end-use applications, the CHPS should adopt these principles to encourage Hubs to design and test accounting frameworks that can conform to and verify them.

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[14] See: https://www.mrets.org/hourlydata/.
[15] See: https://www.gstatic.com/gumdrop/sustainability/247-carbon-free-energy.pdf.
[16] See: https://www.whitehouse.gov/briefing-room/statements-releases/2021/12/08/fact-sheet-president-biden-signs-executive-order-catalyzing-americas-clean-energy-economy-through-federal-sustainability/.
[17] For example, see: https://www.rechargenews.com/energy-transition/eu-green-hydrogen-sector-still-needs-additionality-but-hour-by-hour-rules-were-impossible/2-1-1324462?utm_source=pocket_saves.
[18] For a summary of these issues, see: Tawney, L., Sotos, M., Holt, E., 2018. "Describing Purchaser Impact in U.S. Voluntary Renewable Energy Markets." https://www.epa.gov/sites/default/files/2018-06/documents/gpp_describing_purchaser_impact.pdf.

RECOMMENDATION 3 – AVOIDING LOOSE STANDARDS

Recommendation: The current lack of a marginal emissions accounting framework shouldn't open the door to tracking methodologies with loose causal connections between electricity production and use and that are ignorant of broader emissions impacts on the grid, such as offsetting the use of grid power with renewable energy credits.

Using simpler electricity-based accounting schemes to estimate lifecycle net GHG emissions may tempt the use of methodologies that fail to accomplish this goal in practice. DOE and Treasury have a balancing act to play in setting these standards between permissiveness that stimulates the industry and stringency that ensures emissions reductions and sustainable development for the industry. Because IRA incentives are so large, and because the hub projects are receiving generous federal grants, rapid growth of the hydrogen industry is likely still possible under a stringent emissions accounting framework and vastly reduces the risk of unintended GHG emissions increases.

Several examples can help clarify the risks brought about by accounting schemes that stray too far from the guiding principles in Recommendation 2 and fail to accurately measure net changes in GHG emissions incurred by electrolytic hydrogen production.

First, the use of **Renewable Energy Credits (RECs)** without assurances on additionality, regionality, and time-matching could drive higher GHG emissions from electrolytic hydrogen production. In general, renewable energy resources produce one REC for each MWh they generate. In practice, RECs are subdivided into two camps: compliance RECs and voluntary RECs. Compliance RECs satisfy the specific requirements of state renewable portfolio standard (RPS) or clean energy standard (CES) targets for retail utilities to meet a minimum percentage of their sales with renewable or carbon-free energy.[19] The remaining voluntary RECs are purchased by counterparties including utilities and customers seeking to claim credit for the use of renewable energy and offset the emissions they incur from buying power from the bulk grid.

Compliance RECs (i.e., RECs in a state with a binding RPS or CES) help to ensure that marginal demand is offset by clean power, but it is not guaranteed. RECs help track the share of *clean or renewable electricity* claimed for use in a state—*not* avoided GHG emissions. For example, under most RPSs, a utility could theoretically comply with a higher RPS share by displacing nuclear generation with wind or solar generation, avoiding no emissions. There is no requirement to reduce the emissions intensity of the non-qualifying generation. Therefore, relying on compliance RECs still represents a serious additionality concern for hydrogen production, the subsidies of which—whether through IIJA Hub funding or IRA 45V tax credits—are predicated on the assumption that GHG emissions are being controlled.

Voluntary RECs largely originate from projects built in states without RPS programs—or states that have vastly exceeded their targets—where renewable economics are especially favorable (e.g., Texas, Iowa). Though voluntary RECs were important price supports for new renewable projects in the past, improved renewable economics mean voluntary RECs now trade for cents on the dollar. Thus, electrolyzers' use of voluntary RECs has

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[19] State laws and regulations may also specify how RECs must be procured, such as splitting the share between "bundled" products that require buying RECs and electricity together (i.e., signing power purchase agreements with specific resources for energy and RECs) and "unbundled" RECs that allow for separately buying power and RECs from their respective markets.

the primary effect of consuming credits from existing, economically viable projects, with the incremental load incurred by electrolyzers generating unrelated GHG emissions based on local grid dynamics.

Collectively, REC purchasing is not a sufficient condition to validate electrolytic hydrogen production emissions. Electrolyzers' use of grid power paired with compliance or voluntary RECs would fall short to varying degrees on the three guiding principles under Recommendation 2:

- **Additionality:** Electrolyzers built in RPS states and competing with retail utilities for compliance RECs[20] may fail to satisfy the additionality principle in two ways. First, the state may have an excess of compliance RECs available, meaning an electrolyzer's purchase might fail to incent new renewable project development. Second, this competition could drive compliance REC prices above states' alternative compliance payment (ACP) option, whereby LSEs could pay a ceiling price for each REC they failed to procure in meeting their obligation. In the long run, this might encourage more renewable project development, but the near-term would see higher energy costs and fossil fuel power filling in wherever LSEs opted for ACPs. Electrolyzers using voluntary RECs would fail to meet the additionality criterion, as these RECs would be available regardless of electrolyzer operations.[21]
- **Regionality:** Electrolyzers built in RPS states and competing with LSEs for compliance RECs may satisfy part of the regionality criterion depending on the REC requirements of the state program (e.g., requiring RECs to come from projects built within the same RTO). However, many state programs do not require RECs to come from within the same zone or node, nor do RECs tend to account for transmission losses. Bundled REC products adhere more closely to the regionality principle than unbundled RECs, but they still fall short by allowing more geographic separation and ignoring transmission losses. Electrolyzers using voluntary RECs would fail to meet the regionality criterion on their own, as voluntary RECs can be sourced from anywhere in the country.
- **Time-matching:** Electrolyzers using compliance or voluntary RECs fail to meet the time-matching criterion. Today's RPS programs only use annual accounting to verify compliance. This critical accounting shortfall has motivated public and private entities alike to pursue the development of time-based energy attribute credit (T-EAC) products.[22]

Thus, relying solely on RECs would fail to provide robust emissions accounting that can be used to determine electrolytic hydrogen emissions intensity under the CHPS. RECs are a necessary instrument for tracking clean electricity generation and use, and electrolyzers' consumption of clean electricity should require the retirement of RECs to avoid double-counting, but they are not sufficient in their current form.

Second, **PPAs** face similar risks of increasing GHG emissions from electrolytic hydrogen production, if less so than RECs. PPAs are contracts between producers and offtakers of electricity. They are primarily used to de-risk power generation projects by providing a guaranteed source of revenue and help LSEs hedge against potentially volatile energy markets. A PPA may or may not include the transfer of REC rights between producer and consumer.

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[20] By "competing with compliance RECs," we mean purchasing the same type, vintage, and location of RECs as LSEs under RPS obligations in a state.

[21] Voluntary RECs "have been empirically shown to have no detectable influence on grid emissions, meaning that emission reductions claims are baseless. See: https://scope2openletter.wordpress.com/#ftn2.

[22] See: https://cloud.google.com/blog/topics/sustainability/t-eacs-offer-new-approach-to-certifying-clean-energy.

New clean electricity projects will generally need to obtain one or more PPAs to secure financing. However, the lengths of PPAs can vary; for example, developers may aim for shorter contract terms if they believe energy markets will be in their favor (e.g., trading at higher prices) when PPAs expire. Existing projects also sign PPAs, especially when trying to refinance their terms.

PPAs can be physical or financial in nature. Physical PPAs consists of a set of terms intended to facilitate the actual purchase and use of a project's electricity by an offtaker; essentially, the project promises a certain amount of MWhs at an agreed-upon price and assumes the risk of over- and under-performance. Financial (or virtual) PPAs are strictly financial arrangements between the two parties. Instead of physically delivering power, the project sells electricity into the energy market and the offtaker buys electricity independently of this arrangement. Financial PPAs allow both parties to hedge their risk, agreeing to a "strike price" whereby, in periodic settlements, the offtaker pays the project the difference when market prices fall below it and the project pays the offtaker the difference when market prices rise above it. In both physical and financial arrangements, RECs may or may not be conferred to the offtaker.

Electrolyzers' use of PPAs to verify compliance with the CHPS—assuming these PPAs transfer the associated RECs—risks falling short to varying degrees on the three guiding principles under Recommendation 2:

- **Additionality:** Electrolyzers signing long-term PPAs with new clean electricity resources can claim additionality. However, signing PPAs with existing projects would fail to satisfy this criterion unless they are extending their initial PPAs.[23]
- **Regionality:** Electrolyzers signing physical PPAs may meet the regionality criterion in part, though PPAs are generally workable anywhere within the same RTO. Such PPAs should meet stricter regionality requirements (such as siting both counterparties within the same zone or having both be tied to the same node) and ensure transmission losses are accounted for in the electrolyzer's emissions accounting. Financial PPAs in practice also lack tight geographical restrictions, and thus hold similar risk of non-compliance with this principle. PPA accounting doesn't typically require extra generation to make up for line losses (and to the extent they factor in these arrangements, it is on a purely financial basis), so a true estimate of the upstream emissions impact of running an electrolyzer matched via the bulk power system with generation from a PPA should include extra dirty power used to fill in for line losses.
- **Time-matching:** PPAs generally do not meet the time-matching principle on their own. An electrolyzer that signs physical PPAs to satisfy its full annual electricity consumption would not be guaranteed to produce hydrogen solely in the hours when the associated clean electricity projects are operating; more likely, it would draw grid power in some hours and see the clean electricity project send excess power to the grid in other hours. As a hedging instrument, PPAs are only as effective as they avoid high costs in specific hours, so their time-matched PPAs can be higher value to the consumer than unmatched PPAs. In any case, additional measures would be needed to ensure this criterion is met—given that PPAs need hourly or real-time data to be settled properly, accounting should not be difficult.

Thus, relying on PPAs similarly risks failing to achieve a workable emissions accounting framework on their own under the CHPS. PPAs are likely a necessary instrument for ensuring additionality (via long-term contract terms with new projects) and helpful for adhering more to regionality, but their use in the CHPS is not sufficient for

[23] Once a renewable energy project is built—typically financed through one or more long-term PPAs—its marginal costs to continue operations are near zero. Thus, it's likely to stay online even if it fails to obtain a new PPA halfway through its expected life. Extending original PPAs for the same electrolyzer and clean electricity project pairings are acceptable since the former was responsible for bringing the latter online.

ensuring electrolyzer production satisfactorily accounts for upstream emissions unless regionality concerns are addressed and PPA project outputs are matched hourly with electrolyzer use.

In summary, pertaining to the questions in Request 3c, it's less important to consider which instruments are used in verifying electrolyzer compliance with the CHPS (such as RECs and PPAs) and more important to ensure that any such instruments meet the guiding principles in Recommendation 2.

RECOMMENDATION 4 – ALLOWING A RANGE OF BUSINESS MODELS TO PARTICIPATE

Recommendation: While electrolyzers exclusively connected to new clean electricity resources clearly meet the zero-emissions standard, electrolyzers should be allowed to source electricity from the grid so long as the DOE has developed robust, effective standards that adhere to the requirements of additionality, time-matching, and regionality described in Recommendation 2.

Electrolyzers that are exclusively connected to new clean electricity resources (i.e., not grid-connected) automatically satisfy the principles of additionality, time-matching, and regionality. However, much value exists to allowing electrolyzers to connect to the grid, even though it introduces accounting complexities.

The easiest way to verify the emissions of an electrolyzer is to have a standalone energy park where a new clean electricity portfolio (e.g., solar, wind, and battery storage) feeds into an electrolyzer with neither being connected to the grid. This **"siloed project"** has no need for tracking emissions through the U.S. power grid. But, it also limits the utilization of the electrolyzer to the clean electricity portfolio's output and does not allow any extra (unneeded) generation to flow to the grid—an economically inefficient outcome where assets sit unused or waste energy.

The next easiest approach is to take the standalone co-located energy park and connect it to the grid. This **"closed physical project"** can send extra clean electricity to the grid but not consume grid power,[24] making it cheaper to overbuild the clean electricity portfolio to boost the electrolyzer's utilization rate and potentially bolstering the connecting grid's reliability and reducing consumer electricity costs.

However, this concept requires the clean electricity portfolio to be in the vicinity of the electrolyzer to avoid the high cost of building private, dedicated transmission lines. The energy park may also appear as a different kind of resource to the grid operator due to the clean electricity portfolio's interaction with the electrolyzer's operations, which may require new rules to interconnect.

The closed physical project can be made into a **"closed virtual project"** by interconnecting a contracted clean electricity portfolio in one place on the grid and the electrolyzer in another. In this case, the three principles for using electricity as a proxy for emissions accounting must be verified to fully replicate the dynamics of a "closed physical system," creating a virtual system boundary. This approach allows for situations like building new renewables where land is cheaper and building the electrolyzer at industrial sites where the produced hydrogen would be used. It also helps the grid operator see the clean electricity portfolio as a typical generation resource and the electrolyzer as a separate flexible load with grid benefits. For example, when power prices are high, the

[24] Under an alternative concept, this energy park could be permitted to consume grid power. In this case, time-matching would be crucial to avoid dissociation between when the clean electricity portfolio operates and when the electrolyzer draws power. Any grid power consumed by the electrolyzer would need to have emissions assigned to it, whether through GREET estimates or more robust marginal emissions accounting methodologies (see Recommendation 5).

electrolyzer may ramp down to allow the clean electricity portfolio to fill the need, with the combined project earning a higher profit.

The final concept—an **"open project"**—would allow an electrolyzer to operate from grid power at any time by offsetting the incurred emissions through clean electricity production elsewhere. This would do away with the need for time-matching and close geographic proximity, allowing for more flexibility from both the electrolyzer and associated clean electricity portfolios, with greater grid benefits. However, this requires a yet-to-be-developed marginal emissions accounting framework (see Recommendation 1). Questions of additionality are especially thorny for power purchases outside of long-term procurement windows, as liquid short-term markets mix all kinds of power.

In sum, allowing electrolyzers to connect to the grid brings lower costs for hydrogen production and renewable integration alike due to greater economic efficiencies, but such connections must be conditioned on meeting the appropriate emissions accounting requirements (e.g., adhering to the additionality, time-matching, and regionality principles for closed virtual projects and a marginal emissions accounting framework for open projects).

RECOMMENDATION 5 – PROPERLY ACCOUNTING FOR SOME GRID EMISSIONS

Recommendation: Since the IIJA CHPS and IRA 45V clean hydrogen production tax credit framework of up to 4kgCO_2e/kgH_2 allow for some level of GHG emissions, electrolyzers should be permitted to draw some grid power, preferably with an identified source supplier but otherwise with an estimated emissions impact. However, the use of any grid or fossil power should entail an additional requirement of averaging annual emissions for the purposes of determining compliance with the CHPS and 45V.

To this point, the discussion has mostly focused on how to ensure the verification of net zero GHG emissions from hydrogen electrolysis. However, the proposed CHPS matches the IRA's definition of qualified clean hydrogen, allowing a net increase in lifecycle GHG emissions up to 4 kg CO_2e/kgH_2; so, any electrolysis emissions accounting framework can by definition allow for some generic grid or fossil fuel power.

First, the **GREET tool** estimates for the average emissions intensity of grid power may not be workable in the near term because it does not account for marginal impacts. Take for example the largest U.S. wholesale market, PJM. According to PJM 2021 emissions report[25] the 2021 average marginal emissions rates were between 1,037-1,089 lb. CO_2/MWh while average emissions where 843 lbs CO_2/MWh, a rough 26% increase in emissions that was more than 35% higher in summer months. If electrolyzers had complete freedom of choice between reporting direct emissions from a fossil counter-party generators or using average grid emissions via GREET for grid imports, they would likely always pick the latter and effectively underreport their upstream life-cycle emissions. In the near term, there are a couple work-arounds the CHPS could use:

1. It could disallow or allow only a small fraction of generic grid power (all other dirty sources directly accounted for).
2. It could use a proxy emissions rate for grid imports closer to reality than the GREET average, like a regionwide average marginal emissions factor or that a typical methane gas combustion turbine. Proxy

[25] https://pjm.com/-/media/library/reports-notices/special-reports/2021/2021-emissions-report.ashx

marginal emissions rates should be conservative on the high side, to encourage electrolyzers to use more transparent direct arrangements with lower intensity fossil generators instead.

To eventually improve precision beyond a proxy marginal emissions rate, a marginal emissions accounting framework is needed to measure the marginal emissions incurred by an electrolyzer drawing power from the grid and measure the marginal emissions offset by sending extra power from a new clean electricity resource to the grid. Whatever the CHPS determines is an appropriate emissions factor for generic grid imports can also be used to account for upstream emissions from transmission losses (since these are usually replaced by generic marginal grid emissions).

Second, the allowance of any lifecycle GHG emissions in the hydrogen electrolysis process necessitates a new requirement—an **annual emissions averaging test** to prevent the CHPS from supporting the production of high-emissions hydrogen. This annual emissions averaging requirement is additional to the hourly time-matching requirement, which serves the separate purpose of ensuring that an electrolyzer is operating at the same time that clean electricity is being produced. The annual emissions averaging test requires all electrolytic hydrogen produced in a year to have their emissions averaged in calculating emissions.

For example, suppose an electrolyzer produced 100 kg of H_2, with 85 kg coming from new clean electricity (confirmed via hourly time-matching) and 15 kg coming from grid power (with incurred emissions estimated at 18 kg CO_2e / kg H_2). With the annual emissions averaging requirement, the 100 kg of H_2 would report an average GHG emissions rate of 2.7 kg CO_2e / kg H_2 and, with IRA clean hydrogen production tax credits, be rewarded \$0.60/kg H_2, or \$60 in total. Without this requirement, the electrolyzer could report 85 kg of zero-emission hydrogen for a \$3.00/kg H_2 credit and 15 kg of highly emitting hydrogen for no credit, or \$255 in total. Accounting tricks thus net the electrolyzer an extra \$195.

As another example, suppose the electrolyzer's split was 50 kg of zero-emission hydrogen and 50 kg of grid power hydrogen. Without the annual emissions averaging requirement, the facility would earn an average subsidy of \$1.50/kg H_2, or \$150 in total. Yet, the average emissions for the 100 kg would be 9 kg CO_2e / kg H_2, or roughly the same emissions intensity of hydrogen produced via steam methane reforming. This has the effect of subsidizing hydrogen production with no GHG emissions reduction benefit—clearly against the Congressional intent of the IRA tax credits. Even absent the IRA, if this were allowable under the CHPS, substantial government funding could end up promoting this operational strategy without reducing any—and potentially raising—GHG emissions. An annual emissions averaging test could prevent this unintended outcome.

RECOMMENDATION 6 – PREVENT GAMING OF TAX CREDITS FOR PERVERSE OUTCOMES

Recommendation: The CHPS and deployment of hydrogen hubs should promote industry standards that block the combined use of the IRA's 45V and 45Y tax credits for perverse outcomes at odds with the language of and intention behind the IIJA and IRA. Any IIJA hydrogen hubs should demonstrate, through a robust CHPS, how to prevent hydrogen produced from electrolysis from immediate reuse as fuel for electricity.

In the process of developing hydrogen hubs following the IIJA, it seems perfectly natural that the DOE would look at planned possible configurations that include both electrolyzers aiming to achieve the lowest possible emissions standards under the IRA's 45V (\$3/kg for hydrogen produced with emissions of less than 0.45 kg CO_2e per kg H_2) and power generation equipment meant to use the resultant stored hydrogen to produce electricity during times of peak need. For example, the DOE's \$504.4 million loan guarantee for a clean hydrogen project in

Utah envisages that such hydrogen will support seasonal clean electricity storage for an 840 MW natural gas-fired power plant that is being built to replace the 1,800 MW coal-fired Intermountain Power Project by 2025.[26]

This entirely sensible arrangement, however, opens the possibility for some truly perverse applications of the new tax provision in the IRA. In such a case, clean power would flow to an electrolyzer and produce hydrogen which could immediately be converted back into "clean power," producing nothing but waste and tax credits.

As an example, imagine hydrogen being produced at 20 kg per MWh of input power, such as with Plug Power's EX-4250D PEM system, and then converted via a hydrogen-ready Mitsubishi J-class turbine (44% efficiency single-cycle, 64% combined-cycle)[27]. The round-trip efficiency (X) would then be somewhere between 29% and 43%. Depending on the turbine efficiency, the $26/MWh 45Y production tax credit for clean electricity from hydrogen would work out to a discount (d_X) of 38 cents to 56 cents per kg of hydrogen fuel. The 45V credit for producing hydrogen amounts to $3/kg. For the perverse option of immediately re-converting hydrogen and collecting tax credits to compete with selling the hydrogen at an offtake price (P), we only need P to be less then X/(1-X) times ($3 + d_X) which amounts to between $1.41 and $2.65 per kg of hydrogen (subsidized) depending on whether a single-cycle or combined cycle power plant is being used to reconvert the hydrogen to electricity. These are easily achievable price targets for subsidized hydrogen at today's electrolyzer prices, and will be more easily achieved as electrolyzer production scales and costs fall.

The scenario above sounds like outright tax fraud, and it seems unlikely that the DOE would entertain supporting any project that had this profile. However, the situation is not quite so simple. For example, what if the reconversion happens only hours later? Then the scheme looks like a form of highly inefficient short duration storage which will receive a large net subsidy if the going price for hydrogen is profitable. In another example, suppose there is spare capacity on the hydrogen turbine but hydrogen storage at the hub is full and no customer connected to the hub currently requires hydrogen. Rather than idling the electrolyzer (the sensible outcome) because the effective price for hydrogen is zero, the combination of tax credits above would incentivize the perverse inefficient roundtrip of electricity through the electrolyzer and hydrogen turbine. The turbine would be allowing the electrolyzer owner to bypass the "must sell" provisions in the IRA for qualification for 45V. It is not hard to imagine a slippery slope towards wasteful activity without proper standards.

In its leading position for hydrogen pilots in its hydrogen hubs, the DOE is ideally placed to set the standards for avoiding the perverse outcomes above and to put in place sensible standards for the CHPS with the help of its panoply of experts inside the Department and National Laboratories.

Conclusion

In summary, DOE's CHPS guidance pertaining to electrolytic hydrogen production have major impacts for the net GHG emissions impact of support for clean hydrogen. Specifically, we make the following recommendations:

- **Tying electrolyzer operations to actual emissions impacts:** Any emissions accounting methodology developed for electrolysis should ultimately tie back to the impact on net lifecycle GHG emissions.
- **Verifying the source of clean and dirty electricity::** Until data and methods are available for a more complete system-wide emissions-based accounting framework, a simpler accounting scheme that directly tracks and validates zero-carbon and carbon-intensive electricity used in electrolysis should be

[26] https://www.utilitydive.com/news/doe-loan-guarantee-utah-hydrogen-storage-mitsubishi/625190/.
[27] https://power.mhi.com/products/gasturbines/lineup/m501j

implemented as a proxy, adhering to strict requirements to demonstrate additionality, time-matching, and regionality for the zero-carbon part.

- **Avoiding loose standards:** The current lack of a marginal emissions accounting framework shouldn't open the door to tracking methodologies with loose causal connections between electricity production and use and that are ignorant of broader emissions impacts on the grid, such as offsetting the use of grid power with renewable energy credits.
- **Allowing a range of business models to participate:** While electrolyzers exclusively connected to new clean electricity resources clearly meet the zero-emissions standard, electrolyzers should be allowed to source electricity from the grid so long as the DOE has developed robust, effective standards that adhere to the requirements of additionality, time-matching, and regionality described in Recommendation 2.
- **Properly accounting for some grid emissions:** Since the IIJA CHPS and IRA 45V clean hydrogen production tax credit framework of up to $4kgCO_2e/kgH_2$ allow for some level of GHG emissions, electrolyzers should be permitted to draw some grid power, preferably with an identified source supplier but otherwise with an estimated emissions impact. However, the use of any grid or fossil power should entail an additional requirement of averaging annual emissions for the purposes of determining compliance with the CHPS and 45V.
- **Preventing gaming of tax credits for perverse outcomes:** The CHPS and deployment of hydrogen hubs should promote industry standards that block the combined use of the IRA's 45V and 45Y tax credits for perverse outcomes at odds with the language of and intention behind the IIJA and IRA. Any IIJA hydrogen hubs should demonstrate, through a robust CHPS, how to prevent hydrogen produced from electrolysis from immediate reuse as fuel for electricity.

We look forward to future opportunities to engage in this process and support DOE's guidance design for the CHPS.

Sincerely,

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