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Internal Revenue Service
United States Department of the Treasury
Ben Franklin Station
P.O. Box 7604, Room 5203
Washington, D.C., 20044

December 3, 2022

Re: Notice 2022-58 Request for Comments on Credits for Clean Hydrogen and Clean Fuel Production

Dear Secretary Yellen and Commissioner Rettig:

The Inflation Reduction Act (IRA) creates new incentives for "qualified clean hydrogen" production (under Sections 45V and 48A) with the intent of reducing greenhouse gas (GHG) emissions from hydrogen production. However, because the highest tier of the IRA's clean hydrogen production tax credit of $3/kg is an economic game-changer, and since hydrogen production may additionally benefit from IRA clean electricity tax credits as both an input (e.g., using wind and solar power for electrolysis) and output (i.e., generating power from hydrogen), the manner in which the GHG intensity of hydrogen production is measured has major implications for the IRA's effectiveness in reducing GHG emissions.

With the right guardrails, the IRA's clean hydrogen subsidies can support the decarbonization of today's highly polluting hydrogen production, the power grid (particularly the last 10-20 percent of grid electricity supply which will rely in part on long-duration storage options like hydrogen), and hard-to-electrify sectors like commercial shipping. However, loose guidelines for hydrogen subsidies could dramatically increase GHG emissions and lead market players to game the system, capturing tax credit profits with no real economic contribution. Both would be bad outcomes in themselves, but they also risk undermining support for current policies and stalling future progress on climate.

In parallel, the United States Department of Energy (DOE) is developing a methodology for determining the emissions intensity of hydrogen production in its "Clean Hydrogen Production Standard (CHPS) Draft Guidance," pursuant to the requirements of the Infrastructure Investment and Jobs Act of 2021 (IIJA), Section 40315. As we commented to DOE in response to its draft proposal, the IIJA hydrogen hub funding is an opportunity to explore and inform robust emissions accounting systems for clean hydrogen production, which in turn can over time support more flexible requirements. DOE's efforts should be linked to and inform the U.S. Treasury's guidance development for Sections 45V and 48A. However, in the meantime, more stringent guardrails are necessary to ensure federal policy does not inadvertently worsen GHG emissions from hydrogen production.

These comments focus only on hydrogen produced via electrolysis. They are intended to help the U.S. Treasury design guidance that ensures the IRA succeeds in reducing GHG emissions, maximizing the value of taxpayer money, and helping grow the nascent clean hydrogen industry. They are organized in two parts:

1. A preface detailing our recommendations for measuring lifecycle GHG emissions of electrolytic hydrogen, with accompanying context and examples to explain our reasoning; and
2. A set of responses to specific Treasury requests, drawing from Part 1 to avoid repetition.

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Part 1 – Recommendations for Measuring Lifecycle GHG Emissions of Electrolytic Hydrogen

Central to the fidelity of the IRA's clean hydrogen tax credits is the ability to accurately measure and verify lifecycle GHG emissions from hydrogen production. The statute specifies that the amount of subsidy for qualified clean hydrogen production depends on the lifecycle GHG emissions intensity of the hydrogen production, defined in $kgCO_2e/kgH_2$. This set of recommendations is intended to support the creation of a robust 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 statute and **without** subsidizing the production of such emissions-intensive hydrogen.

Our recommendations are organized in three groups. First, we offer a framework for accurate accounting of upstream GHG emissions incurred by electrolyzer operations as required by the IRA, which tracks changes in marginal emissions across the power system. Second, we describe a simpler approach based on tracking the generation and consumption of electricity used in electrolysis until a marginal emissions accounting framework can be implemented—though several safeguards must be applied to ensure this proxy framework is effective. Third, we flag the potential for market players to farm tax credits via processes that produce no economic value, the risks of which are present regardless of the chosen accounting approach.

Recommendation summary:

1. **Tie 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, inclusive of knock-on effects if existing generation is used. Congressional intent to support qualified clean hydrogen production is better served by adopting more stringent rules for accurately estimating the GHG emissions impact of electrolytic hydrogen than by allowing loose, unproven, or mismatched accounting frameworks that risk substantially increasing GHG emissions.
2. **Use an electricity-based accounting scheme in the interim:** Until data and methods are available for a more complete marginal emissions accounting framework, a simpler accounting scheme based on directly tracking contracted generation and electrolyzer consumption of electricity should be implemented as a proxy, albeit with several crucial safeguards.
    a. **Verify sources of clean electricity:** Track and validate the zero-carbon electricity used in electrolysis, adhering to strict requirements to demonstrate additionality, time-matching, and regionality.

b. **Avoid loose standards:** Conversely, do not open the door to tracking methodologies with loose causal connections between electricity production and electrolyzer consumption that ignore broader grid emissions impacts, such as offsetting the use of grid power with renewable energy credits.
c. **Allow a range of business models to participate:** In addition to simpler business models where hydrogen electrolysis is an exclusive, off-grid consumer of dedicated new clean electricity projects, electrolyzers should be allowed to source electricity from or via the grid, as the benefits of allowing grid connection can outweigh the increased costs of achieving finer measurement of lifecycle GHG emissions.
d. **Properly account for some grid emissions:** Since the IRA's clean hydrogen tax credit framework allows up to 4 $kgCO_2e/kgH_2$ 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 to determine the appropriate tax credit value.

3. **Prevent gaming of tax credits for perverse outcomes:** The Treasury should work with DOE to analyze the possibilities of and set guardrails to prevent perverse "credit printing" outcomes at odds with the language and intention behind the IRA.

RECOMMENDATION 1 – TIE 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, inclusive of knock-on effects if existing generation is used. Congressional intent to support qualified clean hydrogen production is better served by adopting more stringent rules for accurately estimating the GHG emissions impact of electrolytic hydrogen than by allowing loose, unproven, or mismatched accounting frameworks that risk substantially increasing GHG emissions.

The primary purpose of the Sections 45V and 48A clean hydrogen production and investment tax credits is to incentivize the production of qualified clean hydrogen. Clean hydrogen's qualification for different tax credit values is tied to its lifecycle GHG emissions or, more precisely, the net GHG emissions incurred by its production.

Hydrogen electrolysis requires electricity as an input to split water molecules into hydrogen and oxygen. Because electricity supply and demand must be kept in a constant balance, any increase in demand must be met with an equal increase in supply. If electrolyzer operations cause GHG-emitting resources like coal or natural gas power plants to generate more power, these emissions should be ascribed to the resultant hydrogen production. To meet the emission standards under Sections 45V and 48A, producers of electrolyzed hydrogen need to prove that any GHG emissions they cause (e.g., as a result of fossil fuel power plants ramping up to serve electrolyzer operations) are offset by reductions in electric generation emissions elsewhere on the grid to a sufficient degree to stay within one of the credit value tiers.[1]

Unfortunately, there is no current agreement from industry on a best practice for measuring these instantaneous changes in power grid GHG emissions, though there eventually may be ways to do this. For example, in theory, a developer whose electrolyzer uses grid power could track the marginal GHG emissions rate of that point on the power grid—that is, figure out which power plants needed to increase their output to serve the electrolyzer's added demand. The developer could then build new, additional clean electricity resources

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[1] Specifically, these electric generation emission reductions must be *additional* to what would have occurred if the clean hydrogen producer took no action, such as by paying for *new* clean electricity generation.

elsewhere on the grid and track the relevant marginal GHG emissions rates of their locations, figuring out the GHG emissions intensities of the power generation they displaced. If these GHG emission additions are sufficiently offset by GHG emission reductions elsewhere on an annual timescale, the developer could prove its electrolyzer, or its production, has met the conditions to qualify for the Sections 48A and 45V clean hydrogen investment or production tax credits, respectively.[2]

Because of the complexity of electricity systems, figuring out the precise marginal emissions impact of new demand requires estimating a complex counterfactual—what would have happened on the grid if the hydrogen had not been produced? 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.[3] To date, only one independent system operator, PJM, has started to provide some of this locational marginal emissions information.[4]

Given that we currently lack the data and systems necessary to verify the marginal GHG emissions impacts of grid-connected electrolyzers in a consistent manner throughout the country, the Treasury must develop one if it is to both accurately account for the GHG emissions of hydrogen production processes that consumes grid power and allow hydrogen producers maximum flexibility with compliance. This will take time, but it can be developed in concert with DOE and various grid operators and tested in IIJA-funded hydrogen hubs.

In summary, precise marginal emissions accounting would be most appropriate for determining electrolyzed hydrogen's lifecycle GHG emissions. But, in the meantime, Congressional intent to support qualified clean hydrogen production is better served by adopting more stringent rules for accurately estimating the GHG emissions impact of electrolytic hydrogen (as discussed in Recommendation 2a) than by allowing loose, unproven, or mismatched accounting frameworks that risk substantially increasing GHG emissions (as discussed in Recommendation 2b).

RECOMMENDATION 2 – USE AN ELECTRICITY-BASED ACCOUNTING SCHEME IN THE INTERIM

Recommendation: Until data and methods are available for a more complete marginal emissions accounting framework, a simpler accounting scheme based on directly tracking contracted generation and electrolyzer consumption of electricity should be implemented as a proxy, albeit with several crucial safeguards.

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. Thus, the Treasury should require electrolyzers to accurately convey where, when, and from whom they are drawing their power so that GHG emissions impacts can be computed in the absence of a comprehensive grid-wide emissions impacts and offsets accounting scheme.

Recommendation 2a demonstrates why tracking the use of clean electricity by grid-connected electrolyzers to estimate upstream GHG impacts in an accurate manner necessitates strictly following three principles—additionality, regionality, and time-matching. Recommendations 2b and 2c acknowledge the temptation to apply simpler standards that are looser or tighter than those in specified in Recommendation 2a, respectively;

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[2] 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.
[3] https://www.watttime.org/app/uploads/2022/10/WattTime-MOER-modeling-20221004.pdf.
[4] https://dataminer2.pjm.com/feed/fivemin_marginal_emissions/definition.

Recommendation 2b explains the potential GHG emissions increases if any of the three principles are compromised, while Recommendation 2c explains the costs of barring electrolyzers from connecting to the grid. Finally, Recommendation 2d discusses how electrolyzers can estimate the GHG emissions impact from using residual grid or fossil power, whether through contracts or real-time market purchases.

RECOMMENDATION 2A – VERIFY SOURCES OF CLEAN ELECTRICITY

Recommendation: Track and validate the zero-carbon electricity used in electrolysis, adhering to strict requirements to demonstrate additionality, time-matching, and regionality.

The following descriptions of these principles are intended to show that they are **necessary** for accurately tracking and validating the use of zero-carbon electricity in electrolysis and that demonstrating compliance with them is **possible.**

<u>Additionality</u>: Electrolyzers claiming to use clean electricity must source such power from **new** projects built for the primary purpose of supplying power to said electrolyzers.[5] The additionality criterion is the most important of the three for achieving GHG emissions reductions and the easiest with which to measure—if not necessarily achieve—compliance.

> <u>Compliance is necessary</u>: 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.
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> 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.
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> Additionality not only requires that generating projects be recently built explicitly for electrolysis—it also requires that any electrolyzer collecting tax credits or any other government subsidy for clean hydrogen production not be allowed to sell the "renewable" or "clean" attributes of the generation, such as a Renewable Energy Credit (REC), to another consumer. Otherwise, double-counting of clean attributes would ensue, invalidating additionality. As discussed under Recommendation 2b, the additionality criterion remains necessary even when building in a state that has a binding renewable portfolio standard (RPS).
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> <u>Compliance is possible</u>: The additionality criterion can be met straightforwardly by building new, dedicated, co-located clean electricity projects to serve electrolyzers. Additionality becomes harder to

[5] We recognize that "newness" and "primary purpose" are not precise concepts, and we implore the Treasury to work with DOE to define them in order to inform 45V and 48A compliance. 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?

measure via long-term contracts that rely on the bulk power system to connect demand and supply, but doing so is still possible.

Currently operational power generation facilities (or those projects well on their way to be finished prior to passage of the IRA) are very likely not additional, but even later projects may not be additional. Lack of clarity can come when newly developed clean electricity projects would be economically viable even without the additional hydrogen electrolysis load (i.e., they would have been built anyway) and don't have any agreement to sell power to the electrolyzer at key milestones in their development. When the electrolyzer is the primary offtaker with a long-term contract that takes on substantial financial risk for the new generator, there should be a rebuttable presumption of 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 demonstrate compliance when projects are closer in proximity to each other.

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).[6] If generic grid power is provided by ramping up a natural gas-fired power plant,[7] this generation would correspond to approximately 44

[6] 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.

[7] This assumption is often more accurate than using the average GHG emissions intensity of the grid, since the zero-carbon attributes of solar, wind, or other zero-carbon resources may be exclusively claimed by other entities that purchased and retired their associated energy attribute credits.

$kgCO_2e/kgH_2$;[8] in this case, even a 5% loss would drive an upstream GHG emissions impact of 2.20 $kgCO_2e/kgH_2$ when averaged across the 100 MWh of electrolyzer consumption—more than enough to make the most attractive 45V and 48A tax credit value (and even the second-most attractive value) unachievable unless extra clean generation is procured.

Compliance is possible: The regionality criterion may be met by requiring electrolyzer and new clean electricity resource pairings to be located in the same RTO zone or utility service territory **and** requiring some accounting of transmission losses through transmission loss matrices or transmission delivery factors.[9] 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.

Time-matching: As the U.S. power grid integrates more solar and wind resources, the market value and marginal avoided emissions of additional solar and wind generation decreases rapidly.[10] Thus, an increasingly consequential mismatch gets created between the avoided emissions from new clean electricity generation and the emissions from the marginal power produced to serve electrolysis if these do not align in time. Electrolyzers must operate during the **same time intervals** when their dedicated clean electricity resources are generating power, on a MWh per MWh basis. In our proposed electricity tracking proxy scheme, time-matching is easily verified, as grid-connected generators and electrolyzers will have meters tracking hourly power flows that can be compared. Looser schemes involving tradeable instruments like RECs fail this requirement—today's REC instruments can be produced at any time and provide no information about their marginal emission impact.

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 only difficult to verify compliance when electrolyzers are consuming grid power. For self-consumption, time-matching occurs by definition. Under our electricity tracking proxy scheme, hourly matching can be accomplished by comparing meter logs and using some basic telemetry between the generation source and the electrolyzer sink.

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

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[8] The EIA estimates that U.S. electricity net generation from natural gas resulted in 0.97 pounds of CO2 per kilowatt-hour in 2021: https://www.eia.gov/tools/faqs/faq.php?id=74&t=11#:~:text=In%202020%2C%20total%20U.S.%20electricity,CO2%20emissions%20per%20kWh.

[9] 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.

[10] 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.

clean energy purchases.[11] Through Sections 45V and 48A, the Treasury has 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.

RECOMMENDATION 2B – AVOID LOOSE STANDARDS

Recommendation: Conversely, do not open the door to tracking methodologies with loose causal connections between electricity production and electrolyzer consumption that ignore broader grid emissions impacts, such as offsetting the use of grid power with renewable energy credits.

Reasons why arguments in favor of loose standards are misguided: There are several reasons parties may argue for looser standards than those set forth in Recommendation 2a, but it's important to consider them through the lens of the statute's intent. Below, we rebut the following arguments against a stringent electricity proxy accounting standard that requires additionality, regionality, and time-matching.

> Argument 1 – complex or stringent standards would limit commercial viability: Parties may argue that the clean hydrogen industry is in its nascent stages; the Treasury shouldn't hamstring it with regulations that are either complex or that limit commercial viability to fewer types of projects. But, given such large IRA incentives, as well as billions in IIJA funding allocated for R&D, the hydrogen industry is still viable under a rigorous, high-fidelity emissions accounting framework that vastly reduces the risk of unintended GHG emissions increases.
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> The IRA's tax credits of up to \$3/kg should be sufficient motivation to build new projects, as they represent subsidies on the order of \$57/MWh to \$72/MWh depending on the electrolyzer's efficiency (which can stack with clean electricity production tax credits of up to \$31/MWh).[12] As a rough comparison, Lazard's 2021 Levelized Cost of Energy puts unsubsidized wind and solar costs at \$26/MWh to \$50/MWh and \$30/MWh to \$41/MWh, respectively.[13] Further, wholesale electricity prices averaged \$20/MWh to \$60/MWh from 2019 to 2021 across most U.S. power markets.[14] In other words, in input-cost terms, clean hydrogen production subsidies are higher than the input cost of new sources of unsubsidized clean electricity as well as average U.S. wholesale electricity prices. Commercial prospects for hydrogen projects are much more complicated than comparing subsidies, levelized costs, and wholesale electricity costs, but the 45V tax credits' rough tripling of all-in subsidies signals its significance.
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> In any case, Congressional intent of the IRA is clearer around supporting the growth of *low-carbon* hydrogen than supporting the growth of a hydrogen industry regardless of its actual incurred GHG emissions. A scenario in which hydrogen production grows at a slower pace—but actually achieves the

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[11] 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.

[12] These numbers are derived using a typical electrolyzer efficiency of 52.5 kWh/kgH2 at the low end and a cutting-edge electrolyzer efficiency of 41.5 kWh/kgH2, assuming a \$3/kgH2 tax credit value. As standard commercial electrolyzers improve in efficiency, the effective \$/MWh subsidy of clean hydrogen production will trend toward the upper end of this range.

[13] https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf.

[14] See https://cdn.misoenergy.org/20220622%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20IMM%20State%20of%20the%20Market%20Report625261.pdf, Figure 2.

GHG emissions intensities laid out in statute—is preferable to one that grows quickly while in effect driving substantial GHG emissions. In other words, there is nothing inherently good about a much bigger "clean" hydrogen industry unless it also brings the promised emissions reductions.

Argument 2 – standards should start loose and become more restrictive over time: Parties may argue that in order to get the clean hydrogen industry off the ground, the Treasury should begin with looser standards and make them stronger over time as more robust frameworks are developed. However, this approach does not comply with the statute—it implicitly acknowledges adverse GHG emissions impacts associated with the looser standards phase.[15]

Our approach also calls for moving to a more robust accounting methodology over time, but it doesn't compromise in the interim—it instead necessitates more stringent validation requirements (i.e., additionality, regionality, and time-matching) to ensure that GHG emissions thresholds are met despite not having a perfect, more flexible framework available from the start.

The IRA's 45V and 48A credits also only last for projects beginning construction before 2033. So, calls for standards to change over time (e.g., reach maturity by 2030) mean their updates won't be relevant for much of the compliance period.

Argument 3 – the U.S. should learn from or align with international hydrogen standards: Parties may point to the development of European standards for clean hydrogen production, noting the European Parliament recently voted to remove additionality and hourly time-matching requirements.[16] Industry groups in Europe argued these conditions were too onerous due to the need to keep electrolyzers running at high load factors to be economically viable.[17]

However, the U.S. context differs from the European context in at least two key ways. First, the 45V and 48A tax credits are large enough to allow commercial viability of electrolytic hydrogen at lower load factors. Second, onshore wind and solar power in the U.S. have higher capacity factors than in Europe, allowing greater availability.

These differences mean the U.S. should not feel compelled to adopt weaker standards taken up by other countries, particularly given the substantial GHG emissions implications. Adopting weaker standards could also lead to a race to the bottom to support domestic hydrogen industries that are increasingly divorced from GHG emissions impact outcomes.

Examples of how loose standards can worsen GHG emissions: Several examples can help clarify the risks brought about by accounting schemes that stray too far from the guiding principles of additionality, regionality, and time-matching in Recommendation 2a and fail to accurately measure net changes in GHG emissions incurred by electrolytic hydrogen production.

[15] The IRA is very clear in setting its emissions limits—see page 325, lines 15-19: "The term 'qualified clean hydrogen' means hydrogen which is 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."
[16] https://www.rechargenews.com/energy-transition/scrapped-eus-controversial-additionality-rules-for-green-hydrogen-are-history-after-european-parliament-vote/2-1-1299195.
[17] 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.

Renewable energy credits (RECs): RECs represent the transferrable “clean” attributes of renewable or carbon-free energy. Purchasing RECs along with the associated energy output (bundled RECs) is one way to take credit for the clean energy—it is how electric utilities typically comply with state renewable portfolio standard (RPS) requirements. Another method is to purchase just the RECs to offset energy purchases that are not clean (unbundled RECs). Both are problematic from an emissions tracking standpoint—the transfer of 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 RPS or clean energy standard (CES) targets for retail utilities to meet a minimum percentage of their sales with renewable or carbon-free energy.[18] 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 are predicated on the assumption that GHG emissions are being controlled.

Voluntary RECs originate from projects built in states without RPS programs—or states that have exceeded their targets—where renewable economics are especially favorable (e.g., Texas, Iowa). While voluntary RECs still bring some revenue to their associated projects, these projects generally don’t require REC revenue to be profitable, and purchasing them does not materially reduce GHG emissions.[19] Thus, electrolyzers’ use of voluntary RECs would have the primary effect of consuming credits from existing, economically viable projects, with the incremental demand incurred by electrolyzers resulting in new GHG emissions (e.g., from fossil fuel power plants increasing their output).

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 2a:

- **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

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[18] 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.
[19] 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.
[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.

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.

- **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 the GHG emissions impact of 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 markets for time-based energy attribute credit (T-EAC) products.[21]

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.

<u>Power purchase agreements (PPAs):</u> 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 retail utilities hedge against potentially volatile energy markets. A PPA may or may not include the transfer of REC rights between producer and consumer.

PPAs are an important long-term contracting tool for implementing the electricity tracking accounting scheme we advocate, as they contractually engage a counterparty, provide the relevant output meter data to track, and are the starting point for evaluating additionality, regionality, and time-matching. However, they are not enough on their own, and their naïve use may face similar risks of increasing GHG emissions from electrolytic hydrogen production, if less so than RECs.

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.

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

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 IRA’s GHG emissions thresholds—assuming these PPAs transfer the associated RECs—risks falling short to varying degrees on the three guiding principles under Recommendation 2a:

- **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.[22]
- **Regionality:** Physical PPAs with electrolyzers may meet the regionality criterion in part, as PPAs are generally workable anywhere within the same regional market, but financial PPAs are still problematic because they do not involve physical connections between two counterparties (and therefore the counterparties can exist anywhere). In any case, both types of PPAs should either meet stricter regionality requirements (such as siting both counterparties within the same market zone) and ensure that any applicable congestion issues and transmission losses are accounted for in the electrolyzer’s emissions accounting.[23] PPA accounting doesn’t typically require extra generation to make up for any electricity lost to resistance on transmission lines (and to the extent they factor in these arrangements, it is on a purely financial basis); so, a true estimate of the upstream GHG emissions impact of running an electrolyzer matched via the bulk power system with generation from a PPA should account for 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 balance 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. 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, naively relying on PPAs similarly risks failing to achieve a workable emissions accounting framework on their own. 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 demonstrating compliance under Sections 45V and 48A is not sufficient for ensuring electrolyzer

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[22] 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.

[23] Most market operators have means to compensate for congestion and transmission loss issues by adjusting electricity nodal prices and tariffs. This in no way accounts for the parallel impact on GHG emissions, so a lifecycle GHG emissions tracking scheme requires additional measures to reflect true emissions impacts power sales and purchases.

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

RECOMMENDATION 2C – ALLOW A RANGE OF BUSINESS MODELS TO PARTICIPATE

Recommendation: In addition to simpler business models where hydrogen electrolysis is an exclusive, off-grid consumer of dedicated new clean electricity projects, electrolyzers should be allowed to source electricity from or via the grid, as the benefits of allowing grid connection can outweigh the increased costs of achieving finer measurement of lifecycle GHG emissions.

Electrolyzers that are exclusively connected to new clean electricity resources (i.e., not grid-connected) automatically satisfy the principles of additionality, regionality, and time-matching. Thus, a simple way of ensuring accurate GHG emissions measurement under Sections 45V and 48A would be to restrict compliance to these types of projects. However, much value exists in allowing electrolyzers to connect to the grid, despite the accounting complexities this introduces. This section discusses several different types of projects in order to illustrate the benefits of allowing grid connections.

<u>Siloed projects:</u> 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 generation to flow to the grid—an economically inefficient outcome in which assets sometimes sit unused and cannot choose to deliver power to the grid instead when needed (e.g., during a very hot summer evening).

<u>Closed physical projects:</u> 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. This can also potentially bolster the connecting grid's reliability and reduce 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; this prevents economically efficient arrangements where clean electricity projects are sited in areas of high resource quality and land availability and electrolyzers are sited where the hydrogen will be used (e.g., fertilizer production facilities).

<u>Closed virtual projects:</u> 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." 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—see Recommendation 2d.

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

Open projects: 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, regionality, and time-matching principles for closed virtual projects and a marginal emissions accounting framework for open projects).

RECOMMENDATION 2D – PROPERLY ACCOUNT FOR SOME GRID EMISSIONS

Recommendation: Since the IRA's clean hydrogen tax credit framework allows up to 4 kgCO_2e/kgH_2 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 to determine the appropriate tax credit value.

To this point, the discussion has mostly focused on how to ensure the verification of net zero lifecycle GHG emissions from hydrogen electrolysis. However, Sections 45V and 48A allow hydrogen production to incur a net increase in lifecycle GHG emissions of up to 4 kg CO_2e/kgH_2 to earn tax credits; so, any electrolysis emissions accounting framework can by definition allow for some generic grid or fossil fuel power. The allowance of grid or fossil power entails two considerations: how to measure the emissions intensity of such power and how to determine the appropriate 45V and 48A tax credit values for the resultant hydrogen production.

Measuring the emissions intensity of generic grid or fossil fuel power: It may seem permissible to estimate the GHG emissions impact of generic grid power by applying the average emissions intensity of the grid; however, this is rarely an accurate measure of the true GHG emissions impact of an electrolyzer's additional electricity consumption. What matters is marginal emissions—which power plants increased production in response to increased consumption. For example, if half the grid mix is clean energy, and the other half is natural gas, the grid mix average emissions intensity would be half that of natural gas. But, if the clean energy is also running at full capacity and natural gas is used to meet new load, the marginal emissions would be the same as a full natural gas-fired power plant.

The GREET tool, which DOE proposed to use in its CHPS, estimates the average emissions intensity of grid power and is likely unworkable in the near term because it does not account for marginal impacts. As a specific example, take the largest U.S. wholesale market, PJM. According to PJM 2021 emissions report, the 2021 average marginal emissions rates were between 1,037-1,089 lbs 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.[25] If electrolyzers had complete freedom of choice between reporting direct emissions from fossil counterparty generators or using average grid emissions via GREET for grid imports, they would likely always pick the latter and effectively underreport their upstream lifecycle emissions.

In the near term, there are a couple work-arounds the Treasury could use:

1. It could disallow or allow only a small fraction of generic grid power purchased from the open market, with all other dirty sources directly accounted for via contracts and hourly time-matching with specific power plants.
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 of a typical natural gas combustion turbine. Proxy marginal emissions rates should be conservative (i.e., on the high side) to encourage electrolyzers to use more transparent direct arrangements with lower GHG emissions-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 (as described in Recommendation 1). Whatever the Treasury 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).

<u>Determining the appropriate 45V and 48A tax credit value for hydrogen produced with some GHG emissions:</u> The allowance of any lifecycle GHG emissions in the hydrogen electrolysis process necessitates a new requirement—an **annual emissions averaging test** to prevent tax credits from supporting the production of high-emissions hydrogen. This annual emissions averaging requirement is additional to the hourly time-matching requirement detailed in Recommendation 2a, 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 collective emissions averaged for the purposes of determining the appropriate tax credit value.

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 (assuming incurred emissions of 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

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

subsidizing hydrogen production with no GHG emissions reduction benefit—clearly against the Congressional intent of the IRA tax credits.

This concern only presents itself with the Section 45V clean hydrogen production tax credit. Under Section 48(a)(15)(E), the statute makes clear that the Secretary shall issue "regulations or other guidance which recaptures so much of any credit allowed under this section as exceeds the amount of the credit which would have been allowed if the expected production were consistent with the actual verified production (or all of the credit so allowed in the absence of such verification)." In other words, the Section 48A clean hydrogen investment tax credit allows for clawing back up to its full value if the clean hydrogen production facility's annual average output exceeds the greenhouse gas emissions limit it initially promised. The Section 45V clean hydrogen production tax credit should be subject to similar standards, as laid out in the proposed annual emissions averaging test requirement.

RECOMMENDATION 3 – PREVENT GAMING OF TAX CREDITS FOR PERVERSE OUTCOMES

Recommendation: The Treasury should work with DOE to analyze the possibilities of and set guardrails to prevent perverse "credit printing" outcomes at odds with the language and intention behind the IRA.

The high value of the Section 45V tax credit—particularly when paired with one or more instances of earning Section 45Y tax credits—leads to market distortions that could make it profitable to waste energy. Below, we present two examples demonstrating the potential for such subsidized waste.

<u>Hydrogen-to-power-to-hydrogen:</u> One example involves a scenario in which an actor generates electricity from hydrogen, then uses this electricity to electrolyze more hydrogen, producing nothing but waste and tax credits.

First, consider a single party (the "Party") with access to 100 kg of clean hydrogen (e.g., produced via on-site renewables), an electrolyzer, a hydrogen fuel cell that converts hydrogen into electricity, and a hydrogen offtaker:

- In Option A, the Party sells its 100 kg of hydrogen to an offtaker at a price of $1.50/kg, earning $150.
- In Option B, the Party runs its hydrogen through its fuel cell (collecting 45Y credits), then runs the power through its electrolyzer (collecting Section 45V credits), then sells the remaining hydrogen to the offtaker at the same price of $1.50/kg.
    - The fuel cell would produce about 2 MWh from the 100 kg of hydrogen.[26]
    - The electrolyzer would produce about 40 kg of hydrogen from 2 MWh.[27]
    - From this process, Option B would earn $232:
        - 45Y revenue: (2 MWh) * ($26/MWh) = $52
        - 45V revenue: (40 kg H2) * ($3/kg H2) = $120
        - Offtaker revenue: (40 kg H2) * (1.50/kg H2) = $60
- Thus, Option B would earn $82 more in revenue than Option A while wasting 60 kg of hydrogen.

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[26] The calculation is: (100 kg H2) * (33.6 kWh / 1 kg H2) * (60%) * (1 MWh / 1,000 kWh). There is 33.6 kWh embodied in one kilogram of hydrogen. A fair assumption for the efficiency of a fuel cell for power generation is 60% (see link). Fuel cells can ramp up and down quickly and emit only water vapor. See: https://www.californiahydrogen.org/wp-content/uploads/files/doe_fuelcell_factsheet.pdf.

[27] The calculation is: (2 MWh) * (1 kg H2 / 50 kWh) * (1,000 kWh / 1 MWh). Plug Power's EX-4250D PEM electrolyzer system achieves this efficiency: https://resources.plugpower.com/product-literature/ex-4250d-f041122.

Of course, the math is not this simple in reality—electrolyzers and fuel cells have capital and operating costs not accounted for in this revenue comparison. But this dynamic, where a dedicated renewable energy facility generates clean electricity for electrolysis, then the electrolyzed hydrogen is in turn used to generate clean electricity for another round of electrolysis, is entirely possible as electrolyzer production scales and capital costs fall. Electrolyzers are capital intensive, so the unit production cost for hydrogen increases dramatically if the electrolyzer sits idle much of the year and decreases as utilization rates increase. Section 45V is a production tax credit—it incentivizes the owner of an electrolyzer to use as much low-cost clean power as they can source to produce subsidized hydrogen.

In times when there is no more profitable use for clean electrolytic hydrogen or a means to store it, projects as described here may choose to generate electricity from hydrogen and feed it back into electrolyzers (rather than to the grid) to produce more hydrogen and 45V tax credits. If costs fall far enough, the production tax credits could even exceed total costs of such a scheme, making it possible to print money through self-dealing as illustrated above.

Fortunately, Section 45V has a restriction against self-dealing, which should prevent the obvious fraud described here.[28] However, fraud prevention becomes much more difficult to assess when components exist on different parts of the power grid and are owned by separate entities.

For this next example, consider Party A, which owns a wind, solar, and battery project and an electrolyzer in the Oklahoma Panhandle, and Party B, which owns a fuel cell in Tulsa. The two parties are connected by a dedicated hydrogen pipeline and also have access to the same power grid, enabling bilateral trading of both hydrogen and electricity. Party A makes 100 kg of hydrogen from its clean electricity portfolio, then sends it via pipeline to Party B. Party B uses the hydrogen to generate and sell power in Tulsa where prices are higher, such as when transmission congestion prevents Party A from sending clean electricity directly to Tulsa.[29]

Now, consider instances in which Party B sells its fuel cell-derived electricity back to Party A via the transmission grid. Party A then uses this electricity to make more hydrogen to send back to Party B. Given the lucrative 45V tax credits, Party A would be willing to pay a relatively high price for this “clean electricity” to encourage Party B—which also gets 45Y tax credits—to occasionally send it power, particularly when market power prices in Tulsa are low and any hydrogen storage Party B has onsite is full. Again, capital costs could be paid off by other market revenues.

While illustrated for Oklahoma, this example has the potential to materialize in several similar circumstances—such as project pairs in the California Central Valley and LA Basin or in West Texas and Dallas-Fort Worth—where transmission congestion could make dedicated hydrogen pipelines pencil out.

Clearly, this situation is undesirable, existing only to waste energy, land, and other resources while exploiting the law to generate windfall profits; yet, while it effectively mimics the single-party, on-site example, it doesn’t ostensibly violate the self-dealing restriction. This circumstance could be obviated by Treasury guidance

[28] See pages 325-326, paraphrasing: “Qualified clean hydrogen” shall not include any hydrogen unless such hydrogen is produced in the ordinary course of a trade or business of the taxpayer and for sale or use.

[29] Power prices differ by location due to transmission congestion on the grid. For example, assume you have low-cost resources at Point A and high-cost resources at Point B. If you have 5 MW of power demand at Point B but only 3 MW of transmission capacity connecting the two locations, Point B will face higher wholesale electricity prices (i.e., it can only get 3 MW of low-cost power from Point A due to transmission line constraints and must get the other 2 MW from local high-cost power at Point B).

disallowing hydrogen from earning the 45V tax credit if it is produced using electricity from hydrogen-fired power generators, breaking the most lucrative part of this cycle.

Power-to-hydrogen-to-power ("hydrogen-washing"): Another example involves a scenario in which an actor has a source of clean power (e.g., wind or solar) which can sell electricity on the wholesale power market, an electrolyzer with spare capacity, and a hydrogen fuel cell.[30] This actor can produce hydrogen from the clean power (collecting 45V credits), then immediately use the fuel cell to transform this hydrogen into clean power (collecting 45Y credits). This new clean power has been "hydrogen-washed"—as far as other wholesale buyers of electricity are concerned, this electricity is still "clean," yet the actor has harvested significant tax revenue in the process. If the Treasury imposed restrictions described at the end of the "hydrogen-to-power-to-hydrogen" example above, the actor would not be eligible to collect more 45V tax credits if it used the electricity generated by its fuel cell to produce more hydrogen, but other buyers of this clean electricity would not notice that it had been "hydrogen-washed."

First, consider a single party (the "Party") that procures 5 MWh of clean electricity, produces 100 kg of hydrogen with it (collecting 45V credits),[31] and then runs that hydrogen through a fuel cell to produce 2 MWh of "hydrogen-washed" clean electricity (collecting 45Y credits) to sell in the power market.[32] The Party has only lost a net 3 MWh via conversion losses from electrolyzer and fuel cell operations, but it collects $300 in 45V tax credits and $52 in 45Y tax credits for a total of $352.

If instead the Party had used the same 3 MWh of electricity (from conversion losses) to make 60 kg of hydrogen for sale at $1.50/kg, it would collect only $180 in 45V tax credits and $90 from the sale of hydrogen for a total of $270, or a comparative loss of $82.[33] In this case, the Party has no incentive to sell hydrogen—it is better off "hydrogen-washing" the power it would have used to make hydrogen. This example requires no need for hydrogen pipelines or storage. In fact, any time the real-time offtake price for hydrogen is below $2.87/kg (the threshold hydrogen price where the two schemes yield equal revenues in our example), the electrolyzer, is clearly better off "hydrogen-washing."

This threshold price might be a bit lower once the costs of owning or renting the fuel cell, connecting it to the electrolyzer, and briefly borrowing power are considered, but perhaps not by much, making the possibility of consuming clean power solely for tax credits without providing any value to the economy a real threat. Fortunately, Section 45V's restriction against self-dealing should prevent the obvious fraud described here.[34] However, successfully implementing the Congressional intent behind the "must sell" provision will not be so simple, as this scheme could be split between two parties.[35] Further, there are commercial arrangements which

[30] In these examples, a hydrogen combustion turbine could slot in for the fuel cell, though its efficiency may differ from the assumptions used here.
[31] The calculation is: (5 MWh) * (1 kg H2 / 50 kWh) * (1,000 kWh / 1 MWh). Plug Power's EX-4250D PEM electrolyzer system achieves this efficiency: https://resources.plugpower.com/product-literature/ex-4250d-f041122
[32] The calculation is: (100 kg H2) * (33.6 kWh / 1 kg H2) * (60%) * (1 MWh / 1,000 kWh). There is 33.6 kWh embodied in one kilogram of hydrogen. A fair assumption for the efficiency of a fuel cell for power generation is 60% (see link). Fuel cells can ramp up and down quickly and emit only water vapor. See: https://www.californiahydrogen.org/wp-content/uploads/files/doe_fuelcell_factsheet.pdf
[33] Note that in both options, the Party has 2 MWh to sell in the power market, so this revenue cancels out in our comparison.
[34] See pages 325-326, paraphrasing: "Qualified clean hydrogen" shall not include any hydrogen unless such hydrogen is produced in the ordinary course of a trade or business of the taxpayer and for sale or use.
[35] For example, one party could own a solar farm and electrolyzer, sending hydrogen to another party across the street that owns a fuel cell, which in turn could sell its output electricity in the power market. The hydrogen price could be chosen such that both parties benefit from the scheme while engaging in wasteful "hydrogen-washing."

could successfully blend "hydrogen-washing" with actual productive uses for hydrogen which might qualify as a sale, if only a temporary one.

For example, consider the use of a power-to-hydrogen-to-power path that provides short-duration energy storage. In this case, the Party uses 5 MWh to electrolyze hydrogen in the afternoon, briefly stores the hydrogen, runs it through a fuel cell in the evening, and sells the resultant 2 MWh for $100 more than it bought the original power.[36] From this process, the Party would earn $452—$300 in 45V tax credits (for producing 100 kilograms of clean hydrogen), $52 in 45Y tax credits (for generating 2 MWh of clean electricity), and $100 in "energy arbitrage" revenue (for selling power at a higher price than buying it).

Energy arbitrage is useful to the grid because it consumes power at times of low value and provides power at times of high value (hence providing market revenue). In this case, however, energy arbitrage provides only 22% of the total revenue—it is mainly window-dressing on what is essentially "hydrogen-washing."

Compare this to the Party using a lithium-ion battery energy storage system instead. If the Party stored its 5 MWh in a battery with a roundtrip efficiency of 80%, then sells its resultant 4 MWh in the evening for $200 more than it bought the original power, its total profits would only be $200.[37] Thus, the Party would earn roughly double the revenue for sending half as much electricity to the grid if it chose the hydrogen route over a battery—potentially not fraudulent behavior, but plainly an undesirable, economically inefficient outcome.

Clearly, the Treasury should think about how Congressional intent is reflected in the type of scheme illustrated above with hydrogen used as an intermediary energy storage product, finding a way to disallow tax credits in some cases. However, when hydrogen is stored for longer periods of time to provide seasonal storage or backup power, or when it is used as an intermediate energy carrier to circumvent transmission congestion (i.e., there is insufficient transmission capacity for carrying clean power from the point of production to consumers), then the power-to-hydrogen-to-power process incurs costs and provides real value beyond tax credits.

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.[38] Batteries are not viable for seasonal energy storage needs, despite them being clearly superior for short-duration storage, and so hydrogen-as-storage can play a socially productive role. The 45V and 45Y credits can help offset the capital costs of large hydrogen-based seasonal energy storage facilities and making the turbine hydrogen-compatible. It would be unfortunate (and likely very complicated) for the Treasury to block these applications.

Any broad measures to stop wasteful tax harvesting need to be carefully thought out so as not to prevent these actual useful applications. For example, the Treasury might consider disallowing 45V and 45Y tax credits if there is less than 48 hours or less than 10 miles between hydrogen production from clean power and clean power generation from hydrogen consumption.

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[36] For example, the Party could have bought 5 MWh at $10/MWh ($50 loss) in the afternoon when cheap solar power is abundant and sold the 2 MWh post "hydrogen-washing" at $75/MWh ($150 gain) in the evening when higher-cost resources are generating power, resulting in a gain of $100.
[37] Battery energy storage systems receive a 30% investment tax credit under the IRA. However, while not directly comparable, this value is functionally similar to the fuel cell's 45Y production tax credit, which provides a small share of the Party's total revenue
[38] https://www.utilitydive.com/news/doe-loan-guarantee-utah-hydrogen-storage-mitsubishi/625190/.

The examples above are simple and may or may not end up being realistic when all real-world intricacies are layered on, but they provide important illustrations of how parties might potentially farm tax credits while producing only waste. We raise these flags to urge the Treasury to work with DOE to explore more fully these and other examples to establish guidance that prevents perverse outcomes.

Part 2 – Responses to Treasury Questions

This section directly responds to questions laid out in the Treasury's request for information. It often draws from the material in Part 1 to try to prevent confusion that might be caused by only providing a patchwork of answers that are removed from a more holistic picture of how the Treasury might measure lifecycle GHG emissions of electrolytic hydrogen production.

Question (1)(d)

Request being addressed: If a facility is producing qualified clean hydrogen during part of the taxable year, and also produces hydrogen that is not qualified clean hydrogen during other parts of the taxable year (for example, due to an emissions rate of greater than 4 kilograms of CO2-e per kilogram of hydrogen), should the facility be eligible to claim the § 45V credit only for the qualified clean hydrogen it produces, or should it be restricted from claiming the § 45V credit entirely for that taxable year?

Response: The facility should *not* be eligible to claim the Section 45V credit for only the qualified clean hydrogen it produces. However, it also shouldn't be restricted from claiming the credit entirely for that taxable year. Instead, the facility should have to average the total GHG emissions incurred by its annual operations across the total hydrogen it produced in that year, then receive a tax credit (if applicable) at the value corresponding to that average GHG emissions metric. If this average GHG emissions per kilogram of hydrogen metric is greater than 4 $kgCO_2e/kgH_2$, then the facility would not qualify for this highest tier of subsidy under Section 45V.

This condition prevents emissions shuffling, such as by grouping some emissions into one bucket to earn the highest tax credit value and the rest of the emissions into another sacrificial bucket that receives no credits, earning more revenue overall than without shuffling due to the non-linear structure of the subsidy. It also prevents Section 45V from subsidizing the production of dirty hydrogen, with some subset of clean hydrogen paying off the electrolyzer's capital costs and another subset of dirty hydrogen cancelling out any GHG emissions reductions (or potentially worsening emissions relative to a baseline without Section 45V). Finally, this condition helps ensure consistency between the administration of the Sections 45 and 48 clean hydrogen production and investment tax credits (respectively), given that the latter includes a clawback provision should a hydrogen production facility fail to stay under its stated GHG emissions threshold.[39]

See Recommendation 2d of Part 1 for detailed examples of why this annual average emissions test is *necessary and appropriate*. Note that this test is *separate and additional to* the hourly time-matching requirement we call for in Recommendation 2a.

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[39] See pages 336-337 of the IRA, which state: "The Secretary shall issue such regulations or other guidance as the Secretary determines necessary to carry out the purposes of this section, including regulations or other guidance which recaptures so much of any credit allowed under this section as exceeds the amount of the credit which would have been allowed if the expected production were consistent with the actual verified production (or all of the credit so allowed in the absence of such verification)."

Question (1)(e)

Requests being addressed: 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? (i) How might clean hydrogen production facilities verify the production of qualified clean hydrogen using other specific energy sources? (ii) What granularity of time matching (that is, annual, hourly, or other) of energy inputs used in the qualified clean hydrogen production process should be required?

Response: Ideally, electrolyzers should use an accurate marginal emissions accounting framework to assess their lifecycle GHG emissions impact. In the absence of data and methods needed to support such a framework, electrolyzers should estimate their lifecycle GHG emissions impact by tracking and verifying electricity purchases as a proxy, albeit with several critical safeguards.

Specifically, electrolyzers should be required to (1) track and verify the purchase of new, time-matched clean electricity within at least the same ISO/RTO or balancing authority; and (2) estimate the GHG emissions incurred from any use of generic grid or fossil fuel power, such as through conservative estimates of the marginal GHG emissions rate (e.g., from a natural gas-fired power plant) for the former or time-matched contracts for the latter. Hourly tracking is the longest appropriate interval for time-matching, balancing needs of granularity with practicality. The annual average emissions test discussed in Question (1)(d) is also an essential component.

See Recommendations 1 and 2 of Part 1 for more information. Recommendations 2a and 2d are most relevant for understanding the requirements mentioned above, with Recommendation 2b providing more detailed examples of the risks of foregoing any of these suggestions.

Question (2)

Request being addressed: On September 22, 2022, the Department of Energy (DOE) released draft guidance for a Clean Hydrogen Production Standard (CHPS) developed to meet the requirements of § 40315 of the Infrastructure Investment and Jobs Act (IIJA), Public Law 117-58, 135 Stat. 429 (November 15, 2021). The CHPS draft guidance establishes a target lifecycle greenhouse gas emissions rate for clean hydrogen of no greater than 4.0 kilograms CO2-e per kilogram of hydrogen, which is the same lifecycle greenhouse gas emissions limit required by the § 45V credit. For purposes of the § 45V credit, what should be the definition or specific boundaries of the well-to-gate analysis?

Response: The definition of the well-to-gate analysis should include the GHG emissions associated with any electricity use, including those emissions incurred by adding new load (i.e., it’s not enough to buy RECs and claim the use of clean electricity if it ultimately causes a fossil fuel power plant to ramp up). This approach should be consistent across all technologies and hydrogen production setups.

For example, hydrogen produced via a combination of steam methane reformation (SMR) and carbon capture and sequestration (CCS), often termed “blue hydrogen,” uses electricity in both the SMR and CCS processes. This electricity must be included as part of estimating the lifecycle GHG emissions from this production pathway in order to avoid unfair, preferential treatment. Electricity consumption to pressurize hydrogen and purify water onsite should also be considered in lifecycle emissions.

It is also important to note that the CHPS is not a regulatory standard and generally has more permissibility to set looser guidelines. The CHPS does influence the outlay of large grants for hydrogen research and development, so it can support a learning environment that can feed experience into future iterations of Treasury regulations. But, Section 45V has statutory requirements to account for lifecycle GHG emissions of certain thresholds—so while consistency with the CHPS is desirable, the Treasury has authority and good reason to make 45V guidance more restrictive, especially given the impact of its $3/kg hydrogen subsidy.

Questions (4)(d) and (4)(e)

Request being addressed: What procedures or standards should be required to verify the production (including lifecycle greenhouse gas emissions), sale and/or use of clean hydrogen for the § 45V credit, § 45 credit, and § 48 credit? If a taxpayer serves as both the clean hydrogen producer and the clean hydrogen user, rather than selling to an intermediary third party, what verification process should be put in place (for example, amount of clean hydrogen utilized and guarantee of emissions or use of clean electricity) to demonstrate that the production of clean hydrogen meets the requirements for the § 45V credit?

Response: The Treasury should disallow electrolyzers from earning 45V credits for the share of electricity originating from burning hydrogen or using hydrogen in fuel cells. Doing so would eliminate the primary revenue source that would make hydrogen-to-power-to-hydrogen "credit printing" schemes attractive (i.e., using hydrogen-derived electricity to produce more hydrogen for the sole purpose of capturing tax credit revenue). Treasury would be wise to think beyond the economics of today—hydrogen electrolysis, like other clean energy technologies before it, may rapidly fall in cost as the industry scales, making such gaming schemes suddenly profitable.[40]

The Treasury should also work with DOE to study the potential for other types of tax credit gaming, such as power-to-hydrogen-to-power schemes that could circumvent the above-suggested restriction. In such schemes, a party could produce hydrogen from clean electricity, then immediately use that hydrogen to generate clean electricity, again resulting in waste and tax credits. Preventing this scheme becomes more challenging as hydrogen is stored for longer periods of time—for example, short-duration hydrogen storage for power production is still wasteful in most cases (e.g., lithium-ion batteries would waste much less energy to provide the same service with no production tax credits), but seasonal energy storage is an attractive hydrogen application. The Treasury should seek guardrails needed to prevent clearly wasteful behavior while leaving the door open for parties to provide services the power grid will likely need to decarbonize the last 10 to 20 percent of the power grid, as the latter actions are desirable and worthy of federal support.

See Recommendation 3 for detailed examples of these gaming concerns. The Treasury will have a fine line to walk in guarding against fraud while allowing beneficial business models that involve the interplay of hydrogen and electricity.

Questions (4)(f) and (4)(g)

Request being addressed: 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

[40] See: https://www.cell.com/joule/fulltext/S2542-4351(22)00410-X.

calculating the § 45V credit? If indirect book accounting factors that reduce a taxpayer's effective greenhouse gas emissions, such as zero-emission credits or power purchase agreements for clean energy, are considered in calculating the § 45V credit, what considerations (such as time, location, and vintage) should be included in determining the greenhouse gas emissions rate of these book accounting factors?

Response: Indirect book accounting factors such as RECs and PPAs are necessary but not sufficient for measuring an electrolyzer's lifecycle GHG emissions. RECs are necessary, as they must be purchased and retired by the electrolyzer to prevent the originating clean energy project from separately selling RECs to a third party, which would result in double-counting. PPAs are necessary, as they are a tool for proving additionality—that is, for determining that an electrolyzer is purchasing *new* clean electricity financed in part by its hydrogen production rather than redirecting existing clean electricity (in turn back-filled by ramping up fossil fuel power plants).

However, RECs and PPAs are not sufficient on their own. In general, until a comprehensive marginal emissions accounting framework is put in place, electrolyzers must track electricity use from source to sink while adhering to principles of additionality, regionality, and hourly time-matching to verify their use of new, local, and timely clean electricity as summarized in Recommendations 2a and 2b.

For example, without these principles, an electrolyzer could buy RECs from or sign a PPA with an existing wind farm. This wind farm would then direct its electricity toward hydrogen production, and the load it was previously serving would have to source electricity from the grid. Since clean electricity resources have low-to-zero marginal costs and therefore are almost always running at full capacity when available, fossil fuel resources are the most likely to ramp up to serve this load. Thus, the electrolyzer would be incurring new GHG emissions despite ostensibly purchasing zero-carbon electricity. Requirements around additionality, regionality, and hourly time-matching largely fix the highly consequential problems with standard REC and PPA products.

See Recommendation 2a for explanations of these three principles and Recommendation 2b for detailed examples of how foregoing these principles could drive substantial GHG emissions from subsidized hydrogen production.

Questions (6)(b)(i) and (6)(b)(ii)

Request being addressed: What factors should the Treasury Department and the IRS consider when providing guidance on the key definitions and procedures that will be used to administer the election to treat clean hydrogen production facilities as energy property for purposes of the § 48 credit? 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?"

Response: The Treasury should consider requiring facilities to present proof of PPAs with new clean electricity projects within at least the same ISO/RTO or balancing authority (or proof that these projects are co-located with electrolyzers), with enough annual electricity to cover the anticipated load for the electrolyzer. Facilities should also submit contracts with any fossil power they plan to use to firm electrolyzer operations or estimates of the GHG emissions impact of grid power, taking a conservative approach in line with our response to Question (1)(e). Facilities should have a plan in place to track and verify the time-matched use of any contracted electricity (clean or dirty). Finally, facilities should have to submit evidence on an annual basis that they are achieving the GHG emissions rate they used to claim the investment tax credit, with any overages resulting in a claw-back of tax credit value plus a penalty to cover the cost of this effective tax credit "loan." This evidence can be the same as that submitted by facilities claiming the 45V production tax credit.

While our recommendations in Part 1 pertain mostly to the structure of the 45V credit, they are also relevant for the clean hydrogen investment tax credit option.

Conclusion

In summary, the Treasury's regulations under Sections 45 and 48 pertaining to clean hydrogen production have major impacts for the net GHG emissions impact of support for clean hydrogen. Specifically, we make the following recommendations:

1. **Tie 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, inclusive of knock-on effects if existing generation is used. Congressional intent to support qualified clean hydrogen production is better served by adopting more stringent rules for accurately estimating the GHG emissions impact of electrolytic hydrogen than by allowing loose, unproven, or mismatched accounting frameworks that risk substantially increasing GHG emissions.
2. **Use an electricity-based accounting scheme in the interim:** Until data and methods are available for a more complete marginal emissions accounting framework, a simpler accounting scheme based on directly tracking contracted generation and electrolyzer consumption of electricity should be implemented as a proxy, albeit with several crucial safeguards.
    a. **Verify sources of clean electricity:** Track and validate the zero-carbon electricity used in electrolysis, adhering to strict requirements to demonstrate additionality, time-matching, and regionality.
    b. **Avoid loose standards:** Conversely, do not open the door to tracking methodologies with loose causal connections between electricity production and electrolyzer consumption that ignore broader grid emissions impacts, such as offsetting the use of grid power with renewable energy credits.
    c. **Allow a range of business models to participate:** In addition to simpler business models where hydrogen electrolysis is an exclusive, off-grid consumer of dedicated new clean electricity projects, electrolyzers should be allowed to source electricity from or via the grid, as the benefits of allowing grid connection can outweigh the increased costs of achieving finer measurement of lifecycle GHG emissions.
    d. **Properly account for some grid emissions:** Since the IRA's clean hydrogen tax credit framework allows up to 4 $kgCO_2e/kgH_2$ 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 <u>additional</u> requirement of averaging annual emissions to determine the appropriate tax credit value.
3. **Prevent gaming of tax credits for perverse outcomes:** The Treasury should work with DOE to analyze the possibilities of and set guardrails to prevent perverse "credit printing" outcomes at odds with the language and intention behind the IRA.

We look forward to future opportunities to engage in this process and support the Treasury's guidance design for these provisions.

Sincerely,

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