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U.S. Department of Energy
1000 Independence Ave SW
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November 11, 2022

RE: Response to U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance

SECTION 1: DATA AND VALUES FOR CARBON INTENSITY

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

Please see the attached and completed spreadsheet in addition to the following figure.

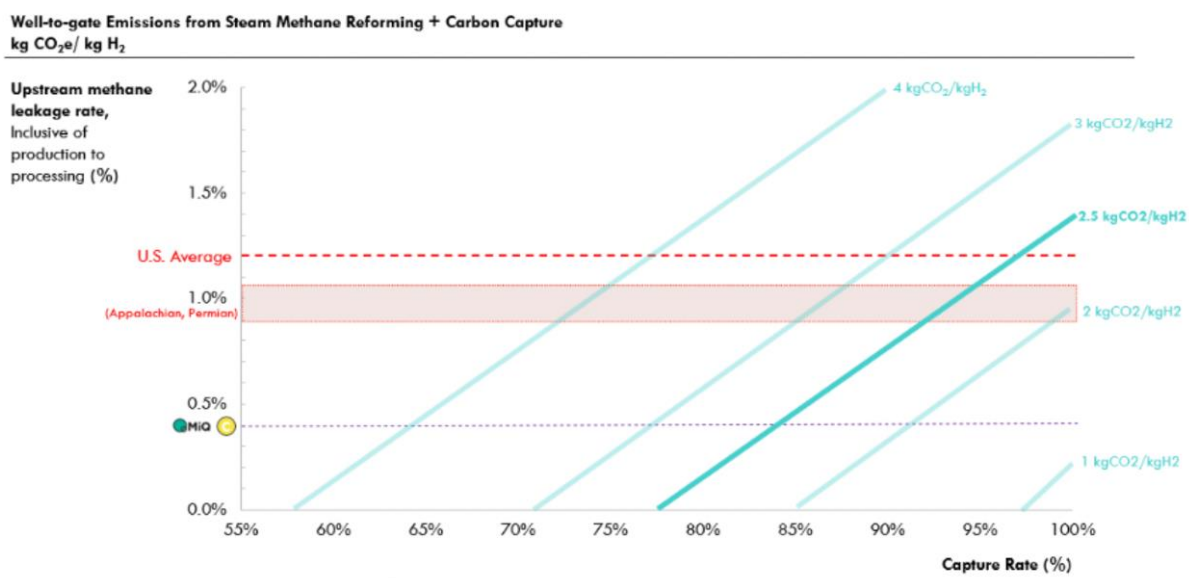

Exhibit 1: Clean hydrogen emissions intensity of steam methane reforming (SMR)with various methane leakage and capture rates on a 100-year methane lifetime including production, the gathering and boosting, and processing segments of the supply chain. The MiQ Certification, a tiered scheme that differentiates natural gas based on its methane emissions at the asset level,is shown in comparison to the average leakage rates for the United States. Sourcing gas with MiQ rating of C or better (<0.4%) is achievable in several US sub-basins.[1]

1b. Lifecycle analysis to develop the targets in this draft CHPS were developed using GREET. GREET contains default estimates of carbon intensity for parameters that are not likely to vary widely by deployments in the same region of the country (e.g., carbon intensity of regional

[1] https://rmi.org/all-clean-hydrogen-is-not-equally-clean/

grids, net emissions for biomass growth and production, avoided emissions from the use of waste-stream materials). In your experience, how accurate are these estimates, what are other reasonable values for these estimates and what is your justification, and/or what are the uncertainty ranges associated with these estimates?

RMI's research has returned different results than the GREET model when it comes to calculating the lifecycle emissions using default emissions intensity estimates because RMI considers cradle-to-gate emissions, not full lifecycle. The GREET model finds that "a steam methane reformer with ~95% carbon capture and sequestration (CCS) could achieve ~4.0 kgCO2e/kgH2 lifecycle emissions by using electricity that represents the average U.S. grid mix and ensuring that upstream methane emissions do not exceed 1%" whereas RMI's modeling of that same scenario estimates closer to 2.5 kg CO2e/ kg H2 (well-to-gate), with 4 kg CO2e/ kg H2 closer to 75% capture rate.[2]

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

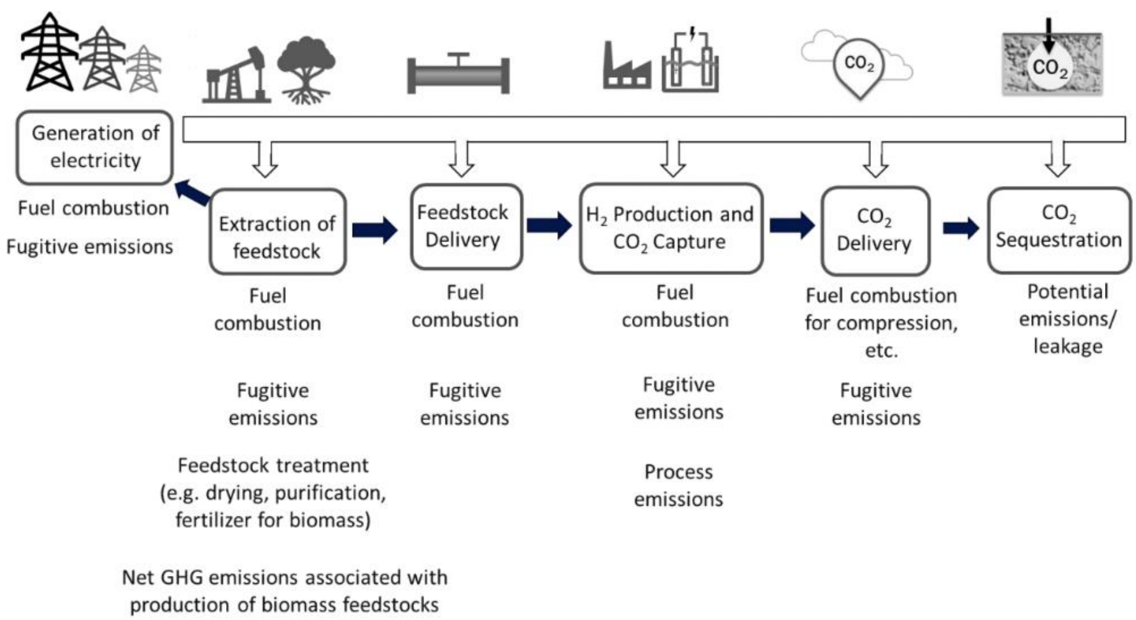

Figure 1: A lifecycle system boundary enables consistent and comprehensive evaluation of diverse hydrogen production systems. Examples of key emission sources within each step typically considered in the boundary are shown above.[11]

Biogenic associated leakage from landfills or biogenic facilities tapped for green hydrogen should also be considered for that source to qualify.

1d. Mitigating emissions downstream of the site of hydrogen production will require close monitoring of potential CO2 leakage. What are best practices and technological gaps associated with long-term monitoring of CO2 emissions from pipelines and storage facilities? What are the economic impacts of closer monitoring?

[2] https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf

Surface and subsurface monitoring for leakage and validating storage capacity is further advanced than carbon capture monitoring. The IPCC has set forth extensive monitoring protocols as well as a framework for identifying environmental risks of underground geologic storage of carbon.[3] The US EPA has released a similar framework as well.[4] These systems can be used to create metrics to evaluate long-term carbon storage and credibility of climate benefit (complementing the DOE's Enhance the Safety and Security of CO2 Storage funding), in part to limit potentially elongating fossil fuel production through enhanced oil recovery.[5]

1e. Atmospheric modeling simulations have estimated hydrogen's indirect climate warming impact (for example, see Paulot 2021).19 The estimating methods used are still in development, and efforts to improve data collection and better characterize leaks, releases, and mitigation options are ongoing. What types of data, modeling or verification methods could be employed to improve effective management of this indirect impact?

Recent research has indicated that leaked hydrogen may contribute more to global warming than previously estimated.[6] Hydrogen leaked to the atmosphere at any point in the supply chain can act as an indirect greenhouse gas, reacting with pollutants like methane to extend their lifetime in the atmosphere.[7] Leaked hydrogen can also impact ozone concentrations, potentially harming air quality and the recovery of the ozone layer, and it can create water vapor in the atmosphere, enhancing the greenhouse gas effect.

Because natural gas is one of the most relevant fuels that hydrogen aims to displace, that makes natural gas leakage frameworks (which are significantly more mature than hydrogen leakage frameworks) a relevant benchmark to compare hydrogen with. On a kilogram-to-kilogram basis, methane will contribute up to three times more warming than hydrogen over a 100-year time frame. Over a 20-year time frame, methane's warming effect is twice that of hydrogen. But hydrogen is more energy-dense than natural gas, so much less fuel is needed to provide energy for the same function. Hydrogen provides 2.5 times more energy than methane per kilogram (120 MJ/kg and 50 MJ/kg, respectively), so methane's warming impact is up to seven times worse than that of hydrogen when considering the warming potential in terms of the energy contained in each molecule.

Comparing the supply chain leakage of a minimally regulated hydrogen system to an average natural gas system indicates that hydrogen will still result in lower emissions (Exhibit 2). If we consider methane leakage rates that have been observed in real-time measurements (rather than assumed in standardized emissions factors), the difference is exacerbated.[8] Green hydrogen producers have demonstrated that leakage during production can be minimized easily at scale with today's technologies and operational best practices. Additionally, significant leakage is less likely for hydrogen than for natural gas, given the relatively high value of hydrogen, newer infrastructure, and the carry-over of lessons learned in detection and monitoring technology, all of which will drive down leakage across hydrogen's supply chain.

[3] https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf
[4] https://www.epa.gov/sites/default/files/2015-07/documents/subpart-rr-uu_tsd.pdf
[5] https://www.energy.gov/articles/doe-announces-nearly-4-million-enhance-safety-and-security-co2-storage
[6] https://www.sciencedirect.com/science/article/pii/S0360319921001804?via%3Dihub
[7] https://research-information.bris.ac.uk/en/publications/global-modelling-studies-of-hydrogen-and-its-isotopomers-using-st
[8] https://rmi.org/making-the-invisible-visible-methane-solutions-offer-down-payment-on-our-climate-future/

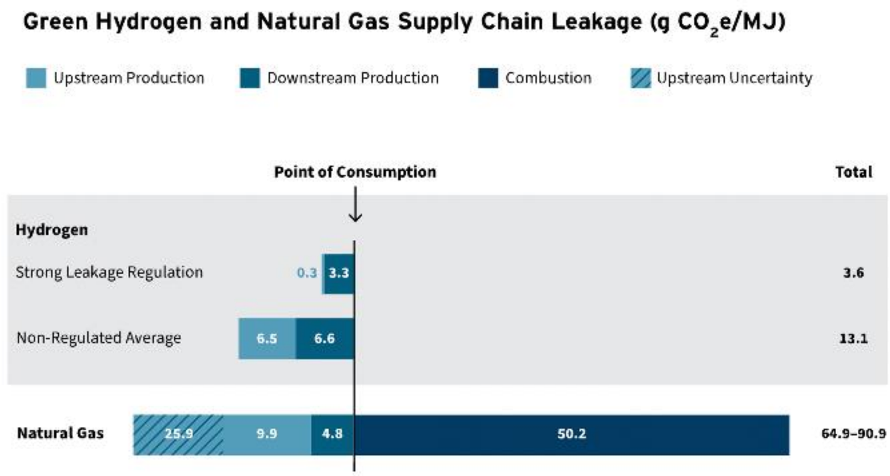

Exhibit 2: Assumptions: GWP20 used for comparison of methane leaked from natural gas and hydrogen in CO_2e. EPA methane leakage data taken from EPA and EIA 2019 reporting values. As EPA is a low-range estimate of emissions, an additional estimate for natural gas leakage as seen in the error bar considers a 1.9 percent leakage rate in keeping with estimates from Alvarez et al., 2018. Combustion values taken from EIA. Hydrogen leakage calculated for a hypothetical hydrogen hub, with leakage assumed to occur during production, transmission and storage, and distribution (as production and use will be co-located). Hydrogen GWP20 of 38 used to include both tropospheric and stratospheric effects. Production leakage rates for hydrogen assumed to be 0.1 percent and 2.05 percent for the tightly regulated and unregulated average, respectively. Transmission leakage rates assumed to be 0.04 to 0.05 percent. Storage leakage rates from underground storage are estimated to be 1 percent and 2 percent, respectively. Distribution leakage rates are assumed to be <0.5%.

1f. How should the lifecycle standard within the CHPS be adapted to accommodate systems that utilize CO2, such as synthetic fuels or other uses?

Uses of hydrogen past the point of production is not within the scope within the same facility.

For example, using clean hydrogen to produce synthetic fuels with captured CO2 from a separate system (e.g. Direct Air Capture) that receives 45Q should be fair game. However, care must be taken to ensure that the carbon capture from blue hydrogen is being permanently sequestered – mixing carbon sources could open the door for fraud.

If hydrogen is being created from a methane pathway and then carbon is re-introduced for synthetic fuels, the process is ripe for abuse. This is an absurd, circular, and comically expensive way to make fuels, but due to credit stacking may be economically viable. The DOE should rely on strict accounting guidelines to require clearly separated pipelines and carbon sources. There may be attempts to mix carbon from many sources into the same infrastructure to confuse auditors and commit fraud.

SECTION 2: METHODOLOGY

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

RMI recommends, at a minimum, core emissions sources be accounted for (as specified under MiQ standards relating to fugitive emissions and incomplete combustion sources for natural gas).[9] Increasing direct measurement (including modeling, metering, enhanced emissions factors) of these sources should follow methodologies already established in best practice guidelines such as MGP or OGMP2.0 for natural gas, including a minimum annual inspection of sources. RMI recommends that at the minimum, the intermediate level of methodological complexity is used when analyzing key emissions categories (i.e., Tier 2 IPCC) to incorporate regional and production factors.[10], [11], [12] This means emissions are to be reported by detailed source type utilizing generic emissions factors, equivalent to Level 3 of the OGMP2.0 framework. for natural gas, including a minimum annual inspection of sources.[13], [14] RMI recommends that at the minimum, the intermediate level of methodological complexity is used when analyzing key emissions categories (i.e., Tier 2 IPCC) to incorporate regional and production factors.[15], [16], [17] This means emissions are to be reported by detailed source type utilizing generic emissions factors, equivalent to Level 3 of the OGMP2.0 framework.

RMI also recommends additional guidance on the Scope 2 emissions framework for grid electricity which is limited, especially the "market-based" compliance mechanisms which refers to the GHG Protocol. DOE should be very careful to avoid weak market-based accounting – there are many methods that check the box for compliance, but fail to physically reduce marginal emissions on the grid induced by the new load. The ISO framework provides guidelines, but is not comprehensive and requires additional guidance. Strong "market-based" compliance approaches should be able to demonstrate additionality, deliverability, and prove that the marginal impacts of the new load onto the grid are below the required thresholds. Furthermore, they should be able to account for RECs with tight temporal granularity, up to the hourly scale, as it has been proven that annual REC systems fail to meaningfully reduce carbon emissions.[18] See Section 4(a) and 4(c) for more detail.

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

The landfill gas (LFG) to hydrogen pathway has one of the lowest well-to-gate carbon intensities after wind and solar in the GREET model.[19] When considering just on-site GHG emissions, the LFG-H2 pathway is considered net-carbon-negative. This is due largely to: 1) the treatment of LFG-related

[9] https://miq.org/

[13] https://methaneguidingprinciples.org/
[14] https://www.ccacoalition.org/en/resources/oil-and-gas-methane-partnership-ogmp-20-framework
[15] https://miq.org/
[16] https://methaneguidingprinciples.org/
[17] https://www.ccacoalition.org/en/resources/oil-and-gas-methane-partnership-ogmp-20-framework
[18] https://zenodo.org/record/7183516#.Y0nRS-zMI-R
[19] https://www.energy.gov/sites/default/files/2022-06/hfto-june-h2iqhour-2022-argonne.pdf

CO_2 emissions as biogenic and therefore zero-emission, and 2) the GHG emissions credits that are taken for the avoided methane emissions when compared to "business as usual" landfill practices.

Existing regulations under the Clean Air Act require landfills of a certain size to install a gas capture system and control their LFG via flaring, combustion for energy generation, or treatment for sale or beneficial use. Of the over 1,100 municipal landfills that report to EPA's Greenhouse Gas Reporting Program (GHGRP), roughly 90 percent of emissions come from landfills that have gas capture systems in place.[20] Landfills that generate sufficient gas to support hydrogen production would likely already be required to capture and control LFG under the Clean Air Act, meaning the avoided emissions of the LFG-H2 pathway vs. BAU would be minimal (relating to potential reductions in methane emissions when LFG is used for SMR rather than flared).

During collection and processing, the LFG to hydrogen pathway carries similar risk of methane emissions as a BAU landfill. Notably, a variety of site-specific factors (including landfill cover material, working face area, gas capture system design, and precipitation) impact landfill gas collection rates, oxidation, and in turn methane emissions from landfills.[21] In calculating carbon intensity, it is critical the GREET model leverage site-specific landfill data (such as under EPA's Waste Reduction, or WARM, model) to fully account for the upstream emissions from uncontrolled methane at landfills.

Recent aerial surveys show methane leakage rates at landfills can be significant. For example, the California Methane Survey flew AVIRIS-NG, mounted on an aircraft, over 270 landfills and 166 organic waste facilities repeatedly during 2016-18 to quantify their contribution to the state methane budget. The survey found methane "super-emitter" activity in every surveyed sector including waste, where a few point sources had an outsized impact on overall emissions (e.g., 10% of sources represented nearly 60% of emissions). Specifically, 30 landfills and 2 composting facilities were the largest methane point source emitters in the state (43% of total emissions in the study), exhibiting persistent, potentially anomalous activity.[22]

We recommend DOE revise the LFG-H2 pathway to fully account for uncontrolled methane at landfills and potential fugitive emissions. First, we recommend DOE require hydrogen projects that use landfill gas as a feedstock to certify their methane emissions throughout LFG collection, processing, and transmission– supported by emissions monitoring technologies and LDAR (leak detection and repair) practices at the landfill. DOE should also require landfills used in clean hydrogen projects to comply with a set of best management practices that can improve collection efficiency (e.g., optimizing well density, minimizing the active work face, using biocover materials, and installing emissions monitoring technology). Absent these changes, classifying landfill gas as a clean feedstock creates perverse incentives for landfill operators who by prioritizing methane

[20] NPRM at 37008 https://www.govinfo.gov/content/pkg/FR-2022-06-21/pdf/2022-09660.pdf

[21] Lee U, Han J, Wang M. Evaluation of landfill gas emissions from municipal solid waste landfills for the life-cycle analysis of waste-to-energy pathways. Journal of Cleaner Production. 2017;166:335-342. https://doi.org/10.1016/j.jclepro.2017.08.016; Barlaz et al. (2009) Controls on Landfill Gas Collection Efficiency: Instantaneous and Lifetime Performance, J. Air & Waste Manage. Assoc. 59:1399.

[22] Riley M. Duren et al. Final report for California Energy Commission: Energy Research and Development Division (2020, July). *Final Project Report: The California Methane Survey*. https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2020-047.pdf; Riley M Duren et al. (2019). *California's methane super-emitters*. Nature, 575: 180–184. https://doi.org/10.1038/s41586-019-1720-3

generation for hydrogen production over emissions reduction could create potentially worse outcomes than under business-as-usual practices.

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

No response to contribute

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

We recommend that byproduct hydrogen production must reflect a weighted intensity of the production inputs; while it is not an intentional production method, the relative footprint should be recognized so as to not create an inconsistency in the broader assessment of GHG emissions.

SECTION 3: IMPLEMENTATION

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

For grid-connected electrolysis, the DOE will need to verify that the electrolyzer is contracting additional clean generation to offset the new load.

To verify emissions for electrolyzers, there are several potential systems that the DOE could adopt:

- **Behind-the-meter generation with a direct connection from clean resources:**
  - The LCA should not include the construction costs of the electricity generation facilities or associated transmission construction
- **Average grid emissions or residual grid mix**
  - Leverage data from the EIA – this data should be public on annual time-steps for each major grid region and trivial to calculate
  - More robust hourly data is available in some jurisdictions;
- **Time-based Energy Attribute Certificates** – piloted by Google[23]
  - A critical improvement to the traditional REC markets in that it drives effective emissions reductions
  - As these markets develop, hub developers should be able to use these to demonstrate compliance with the required LCA and the associated hydrogen production tax credits.

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

- Energy Tag and over 100+ global organizations have developed and implemented T-EACs with a full methodology available[24]
- An overview of existing hourly tracking projects worldwide demonstrates this system's readiness for deployment by the DOE for LCA compliance[25]
- After internal conversations with Ben Gerber, the M-RETs CEO, the M-RETs system can be scaled nationally in 12-18 months and has already piloted similar programs in the MISO region if the PTC requires it[26]

- **Locational Marginal Emissions** – piloted by REsurety, Brattle, and Microsoft
  - "The LME is a metric that measures the tons of carbon emissions displaced by 1 MWh of clean energy injected to the grid at a specific location and a specific point in time" - REsurety, Brattle whitepaper[27], [28]
  - The LME is an economical way to build renewable projects to displace the overall grid emissions to offset induced emissions by a new load
  - Modeling organizations like Watt-Time have developed a methodology to infer the marginal emissions despite the lack of full data available in many locations[29]

To verify additionality:
Additionality can be a challenge to verify, however there are several principles that are critical:

- Credits from existing renewable facilities should not count, as no additional clean generation is coming online to fill the new load
- Projects are not additional if their environmental attributes are used to fulfill compliance to state policies (e.g. Renewable Portfolio Standards)
- Direct financial relationship between the project and the offtaker

RMI has also developed an "financing" test for projects that calculates the "additional" value of EACs based on the value of the EAC divided by the levelized cost of energy that could provide a simple and quantifiable method to establish additionality.[30]

Edge cases for additionality include:

- Purchase of renewable power that otherwise would be curtailed (sub-zero LMP)
- Large low-carbon loads that are not receiving priority economic dispatch (e.g. nuclear that is getting displaced from the generation stack)

The DOE should look across the government to pull together the data for this effort. The Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability requires

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[24] https://energytag.org/wp-content/uploads/2022/03/20220331-EnergyTag-GC-Use-Case-Guidelines-v1-FINAL.pdf
[25] https://docs.google.com/spreadsheets/d/1zdwTHf2X_jxqeVJoDAPImRrhnHDiItAd9jNBGEsJv6g/edit#gid=1741548934
[26] https://www.mrets.org/hourlydata/
[27] https://www.businesswire.com/news/home/20210714005708/en/%C2%A0REsurety-launches-%E2%80%9CLocational-Marginal-Emissions%E2%80%9D-data-product-to-empower-customers-to-measure-and-maximize-how-much-carbon-they-cut-through-clean-energy-purchases
[28] https://resurety.com/wp-content/uploads/2022/03/REsurety-Locational-Marginal-Emissions-A-Force-Multiplier-for-the-Carbon-Impact-of-Clean-Energy-Programs.pdf
[29] https://www.watttime.org/marginal-emissions-methodology/
[30] https://www.energyweb.org/wp-content/uploads/2022/06/Renewable-Energy-Emissions-Score-Approach_FINAL_NT.pdf#:~:text=The%20RE%20Emissions%20Score%20is,on%20emissions%20and%20the%20energy

federal buildings to procure clean energy matching the hourly load.[31] The DOE should consider collaborating on this methodology and build a shared process and data structure.

In addition, the Infrastructure Investment and Jobs Act calls for the US Energy Information Administration (EIA) to publish spatially and temporally granular electricity emissions rate data which can be used to calculate the emissions profile of electrolysis. The DOE should engage with the EIA to incorporate this more granular data where available.

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

Natural gas supply to use (unless there is a direct connection between the two) is fungible. Therefore, it is typically proactive enough to utilize national averages for leakage rates. Producers do have a choice in how to credibly differentiate their product through purchasing certified gas. There are multiple systems for verifying this, including the MiQ standard, Equitable Origin EO100, and Project Canary TrustWell.[32], [33],[34]

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

Renewable energy credits and power purchase agreements do not, on their own, demonstrate low-emissions electricity that could then qualify hydrogen producers using grid electricity. Hydrogen produced with average grid electricity on average has an emissions intensity of over 20 kg CO2e per kilogram of hydrogen, over five times the qualifying threshold.[35] Any book-and-claim system that is used to claim lower lifecycle emissions must affirmatively prove that the emissions impact of the new electrolyzer load on the grid is being mitigated. Recent modeling demonstrates that additionality, regionality, and granular temporal matching (with associated measurements) are all required to eliminate the emissions impact of the new load.[36] Temporal matching includes either long-run hourly locational marginal emissions accounting, or hourly MWh matching.

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[31] https://www.whitehouse.gov/briefing-room/presidential-actions/2021/12/08/executive-order-on-catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability/
[32] https://miq.org/
[33] https://www.equitableorigin.org/adopt-eo100/
[34] https://www.projectcanary.com/private/trustwell-and-rsg-definitional-document/
[35] One kg H2 production requires roughly 50-55 kWh electricity and according to the EPA eGRID2020 data, average grid intensity is roughly 0.3726 CO2e/kWh, for a total emissions intensity ranging from 18.6 -20.5 kg CO2e per kg H2 produced.
[36] Wilson Ricks, Qingyu Xu and Jesse D. Jenkins, "Enabling grid-based hydrogen production with low embodied emissions in the United States"

If the DOE allows for PPAs or annual matching, the agency should be very clear that this compliance mechanism will allow the deployment of hydrogen that dramatically exceeds the lifecycle greenhouse gas emissions threshold established by the Infrastructure Investment and Jobs Act.

The DOE's decision on the Clean Hydrogen Production standard will influence the implementation of the 45V clean hydrogen production tax credit and should complement that methodology. The DOE should plan on working actively with the Treasury to support implementation of that program with learnings and data from the implementation of the hubs program.

In the Inflation Reduction Act, the GREET Model is called out in legislation as the default mechanism to ensure clean hydrogen production meets the greenhouse gas lifecycle analysis necessary to apply for the credit. The text also allows for a successor model to be approved by the Secretary of the Treasury. A similar framework could be developed for the CHPS. However, the GREET Model is best suited for green hydrogen produced by behind-the-meter electricity and blue hydrogen utilizing carbon capture technology. If Congressional intent is interpreted to allow for grid-connected hydrogen production to be able to qualify as low carbon hydrogen through a book and claim system, it will be critical for that system to reduce effective greenhouse gas emissions as outlined in the Senate colloquy between Senators Carper and Wyden.[37]

We have identified three keys and one non-starter for a regulatory system to ensure "clean" hydrogen is living up to its name:

1. Strict additionality
2. Tight regionality
3. Short temporal matching
4. No unbundled credits

Additionality

Additionality is a key check to ensure that electrolyzer loads are contracting new clean generation that would not otherwise exist to offset the grid emissions induced by the new load. New electrolyzer loads must be paired with new clean generation, otherwise fossil generation is covering the difference, making this energy ineligible for the hydrogen credit.

Any system set up to accredit producers with clean energy credits must ensure that the credits represent additional clean electricity, electricity that would not have otherwise been generated without the investment from the producer. Existing renewable generators are already covering loads on the grid – attributing this clean energy towards electrolyzers shuffles the attribution of clean energy but contributes to no real emissions reductions on the grid.

Regionality

Regionality is the establishment of some geographical boundary within which the clean power being used for credit must be located. Accounting schemes range from "anywhere", to the same grid, to the same RTO, to the same interconnection node. More flexibility increases the chances that transmission constraints drive unintended consequences. Flexibility can also allow for hydrogen

[37] https://www.govinfo.gov/content/pkg/CREC-2022-08-06/pdf/CREC-2022-08-06-pt1-PgS4165-3.pdf, pages 1-2.

production to be strategically located in areas that have more clean energy production, while procuring clean energy from areas where it is cheaper to deploy.

In a simpler system that is only attempting to load match on a longer temporal basis (i.e. yearly matching), establishing narrow regional boundaries is incredibly important for emissions reductions system wide. The Princeton ZERO Lab report found that tighter regionality led to greater emissions reductions.[38]

Temporal Matching

Temporal matching can range from an hourly matching to annual matching to no matching (unbundled, stored credits). The more granular the time period that is required for producers to offset their energy usage with clean energy (i.e. hourly), the more assurance the government will have that the hydrogen producers are offsetting any induced emissions from grid-powered electrolyzers with clean energy operating at the same time.

Unbundled clean energy credits are a non-starter.

A system allowing unbundled clean energy credits to qualify hydrogen generators as clean risks gaming and emissions increases due to the lack of integrity and additionality requirements.

If IRS allows for unbundled credits, the PTC could allow projects that use natural gas as the marginal resource and claim credits that are not actually tied to additional clean power added to the grid. These projects could receive the maximum PTC payments while emitting 40 times more carbon than the credit's strictest requirements.

New clean generation is necessary to match new electrolytic loads, otherwise the effective greenhouse gas impact is worse than existing steam methane reforming (SMR) process for hydrogen creation. Allowing unbundled credits would directly contradict the language and the intent of the law.

Two schemes worth consideration that place effective requirements on mechanisms to qualify clean hydrogen:

1. <u>24/7 Carbon Free Electricity (CFE)</u>

24/7 CFE requires that load be matched with additional clean supply on an hourly basis throughout the year, typically with corresponding regionality requirements. This eliminates the weakness of matching load on an annual basis, in which annual load demand can be fully offset by clean supply, but there are still significant amounts of time throughout the year in which dirty power is meeting demand.[20] The Princeton ZERO Lab study finds that requiring hydrogen producers to match their electricity consumption on an hourly basis with local clean generation can achieve effective emissions reductions to meet the low carbon standard.[39]

On December 8, 2021, President Biden signed the Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability. In this Executive Order, the federal government

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[38] https://zenodo.org/record/7183516#.Y0nRS-zMI-R
[39] Princeton University ZERO Lab, "Policy Memo: Cost and Emissions Impacts of Hydrogen Production Tax Credit Implementations," page 4. https://zenodo.org/record/7183516#.Y0XlsnbMKUk.

is required to match 50% of its electricity demand with 24/7 CFE by 2030.[40] The 45V PTC could help accelerate the development of a 24/7 CFE system which will be necessary to meet this commitment.

24/7 matching can add costs and complexity to projects, while encouraging necessary investment for grid scale decarbonization in the long run. For example, if a hydrogen producer seeks to achieve 24/7, they would need to ensure there is enough clean power they can purchase to offset their total load at every hour. Given that this system requires diverse resources that include some immature technologies, it has the potential to be less economically efficient than a pure emissions-based approach like marginal emissions accounting. However, a 24/7 approach encourages deep investment in emerging clean energy technologies that will be required for full grid decarbonization, such as enhanced geothermal, battery storage, and other clean firm technologies.

2. Marginal emissions accounting

Unlike 24/7 CFE which focuses on offsetting single-project loads, marginal emissions accounting focuses on offsetting *emissions*. This approach calculates the emissions intensity of the grid where the demand is induced and requires procurement of clean energy at a location and time that reduces emissions by the same amount.[41] This system ensures that emissions are offset, whereas other approaches use energy usage as a proxy for emissions.

There are outstanding questions with this approach, including how to provide certainty for project developers as the grid changes and the marginal emissions impact of the hydrogen producer and the procured clean energy change. For example, if a hydrogen producer enters into a power purchase agreement for a solar facility on a dirty grid which avoids significant emissions in the present, they will need some type of certainty that they can count on those avoided emissions for a specific amount of time. Developers will need to model future marginal emissions rates and offsetting induced emissions, which may inject additional risk.

Of note, the Infrastructure Investment and Jobs Act requires the Energy Information Administration to add estimated marginal emissions per megawatt hour of electricity generated for different balancing authorities and nodes.[42] This could be an opportunity to make the data and measurement needed to use marginal emissions for an accreditation system more readily available.

Both schemes will require significant investment in data availability and sophisticated accounting systems to ensure accuracy and accountability. They may be a year or two away from full operability. A near term regulatory scheme should help provide the groundwork for either a 24/7 CFE system or a marginal emissions accounting approach, and at the very least it should ensure requirements of additionality, strict regionality, and some level of temporal matching.

Overview of key features for 24/7, marginal, and annual accounting method

[40] https://www.federalregister.gov/documents/2021/12/13/2021-27114/catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability
[41] https://www.watttime.org/news/insight-brief-accounting-for-impact/
[42] https://www.watttime.org/app/uploads/2022/05/WattTime-HowWattTimeGaugesAndIteratesOnMOERAlgorithmQuality-vFinal-202205.pdf

	24/7 Carbon Free Electricity (CFE)	Marginal Emissions Accounting	Annual accounting without additionality
Additionality	Requires additionality.	Requires additionality.	No additionality requirements.
Regionality	Narrow regional boundaries. The tighter the regional boundaries, the greater the emissions reductions and deep grid decarbonization. However, tighter regionality can also lead to greater costs.	Does not require regionality. Relaxed regional restrictions can create efficiency, allowing clean energy to be built in the dirtiest grids, while hydrogen projects are built within cleaner grids.	No regionality requirements.
Temporal Matching	Hourly matching.	Flexibility in the granularity of these measurements. Hourly matching is reasonable.	Annual matching.
Variable Measured	Electricity generation is measured and offset.	Marginal emissions rate is measured and offset.	Electricity generation is measured and offset.
Impact	Deep decarbonization in tighter geographical areas. Investment in clean firm technology is incentivized. Largely ensures clean hydrogen production.	Carbon emissions are fully offset. Hydrogen projects are encouraged to be built in areas with robust clean energy and curtailed renewables. New clean energy is built in dirtiest grids to offset marginal emissions most efficiently.	Credits are transferred to hydrogen projects from already existing clean resources, diverting clean energy away from other grid uses. Fossil fuel generation steps in to meet overall load and emissions increase.

Exhibit 3

Comparing 24/7 and Marginal Emissions Accounting

	24/7 Carbon Free Electricity (CFE)	Marginal Emissions Accounting
Cost-efficient emissions reductions	More expensive in some locations	Short-term more efficient, costs increase over time
Producer incentives aligned with system-wide emissions reductions	Supports local decarbonization	Supports global decarbonization
Tracking	Hourly generation data	Hourly marginal gird emissions
Certainty for projects developers and industry	Requires forecasting and flexible loads	Marginal emissions change over project lifetime
Provides near-term incentives for technologies that will be useful in long-term grid decarbonization	Yes	No

Exhibit 4

3d) What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0 kgCO2e/kgH2)?

Under the proposed standard, current production pathways will face a tighter price market. Certain pre-existing sites may choose to manage carbon emissions profiles that currently exceed the proposed standard by implementing carbon capture technology. For hubs that choose to utilize CCS, requiring higher levels of carbon capture directly increases the overall cost of production.[43]

Furthermore, it is important to consider how to align these standards with the EU and other regions to ensure that regional producers have access to export markets. A robust export market can help support regional markets by channeling additional demand and demonstrating a broader set of use cases.

[43] https://www.sciencedirect.com/science/article/abs/pii/S1750583620306642

SECTION 4: ADDITIONAL INFORMATION

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

The CHPS cannot be evaluated alone in the context of the Bipartisan Infrastructure Law, but must also take into account the 45V tax credit and the need for strong international standards. DOE should use this process to develop its capabilities to evaluate real-world projects at scale, develop a strategy to manage edge-cases, and gather data in a secure and scalable manner. Investments in administrative capacity are crucial to sufficiently evaluate project's performance.

The DOE should prioritize pro-active evaluation where possible, with clear guidelines on how the agency will restrict funds if over the course of the project the lifecycle emissions are not able to achieve the reported amounts, or there are changes is strategies or sourcing. In the case of biogenic or methane-based pathways, adjusting the source of materials from a basin or producers can dramatically alter the LCA. In addition, changing the use-case of sequestered carbon down-the-line can also undermine the LCA. The DOE should provide a process for validating adjustments throughout the project lifespan, especially for projects that plan on also receiving the production tax credit.