CLEAN AIR TASK FORCE

November 14, 2022

Hydrogen and Fuel Cell Technologies Office,
Office of Energy Efficiency and Renewable Energy,
Department of Energy

Submitted via email to Cleanh2standard@ee.doe.gov

Re: Stakeholder comments in response to Clean Hydrogen Production Standard Proposal (87 Fed. Reg. 58776)

Clean Air Task Force ("CATF") is pleased to respond to Department of Energy's ("DOE") draft guidance for a Clean Hydrogen Production Standard ("CHPS"), which was developed to meet the requirements of the Bipartisan Infrastructure Law ("BIL"), Section 40315. CATF is a global nonprofit organization working to safeguard against the worst impacts of climate change by catalyzing the rapid development and deployment of low-carbon energy and other climate-protecting technologies. With 25 years of internationally recognized expertise on climate policy and a fierce commitment to exploring all potential solutions, CATF is a pragmatic, non-ideological advocacy group with the bold ideas needed to address climate change. CATF has offices in Boston, Washington D.C., and Brussels, with staff working remotely in all parts of the world.

Statutory Background

Subtitle "Hydrogen Research and Development" of the BIL was established to "accelerate research, development, demonstration and deployment of hydrogen from clean energy sources." 135 Stat. 429 § 40311(b). First established in 2005, the initial purpose of Congress' hydrogen programs was to "eliminate most emissions from the transportation sector." 42 U.S.C. § 16151 (2005). This year, Congress found that hydrogen plays a critical part in the comprehensive energy portfolio of the United States across multiple sectors and its use provides environmental benefits. 42 U.S.C. § 16151(a) (2021). To that end, and as relevant here, Congress directed DOE to establish one program to support development of regional clean hydrogen hubs and another to conduct research relating to hydrogen energy and related infrastructure.

To further define the two programs' goals, Congress ordered the Secretary to develop a standard for the carbon intensity of clean hydrogen production (the clean hydrogen production standard, or "CHPS"). Congress defined the on-site carbon intensity of clean hydrogen[1] and indicated that the CHPS will apply to hydrogen production from a diverse array of sources. *Id*. at § 16166(b)(1), (c). But Congress left it to DOE to establish a standard for the lifecycle emissions for clean hydrogen production by considering technological and economic feasibility. *Id*. at § 16166(b)(1). This requires DOE to appropriately account for emissions from the full hydrogen

[1] "Clean hydrogen" is defined as "hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide equivalent produced at the site of production per kilogram of hydrogen produced."

production chain and select a level of stringency commensurate with Congress' goals of "support[ing] clean hydrogen production," *id.* at § 16166(b)(1)(A), "demonstrat[ing] a standard of clean hydrogen production . . . by 2040," *id*. at 16154(b)(2) and "accelerating research, development, demonstration and deployment of hydrogen from clean energy source." *id*. at § 16151(b).

Congress appropriated $8 billion to DOE to create at least four "regional clean hydrogen hubs." *Id*. at § 16161a(c), (d). In selecting hubs, DOE must account for a variety of factors, including diversity in feedstock, end-use, and geography. *Id*. at (c)(3). In addition to these statutory requirements for selecting hubs, DOE must support the development of hubs that "demonstrably aid the achievement" of the CHPS. *Id*. at (b)(1).

Congress also appropriated significant funds to DOE to promote research and development and partner with the private sector to "advance and support . . . a series of technology cost goals oriented toward achieving" the CHPS. 42 U.S.C. § 16154(e)(1). DOE is directed to, among other things, focus on research and development that "reduce[s] the life cycle emissions" of hydrogen production. *Id*. at (c)(1)

The BIL directs the DOE to utilize the CHPS in both the Regional Clean Hydrogen Hubs program and the Clean Hydrogen Research and Development program. It is therefore critical that DOE develops a CHPS that carefully considers all lifecycle emissions and ensures that hydrogen is truly "clean."

Introduction

Today, 80% of global final energy demand is served by high-emitting fuels, and despite rapid electrification, some projections suggest that fuels could still serve 25% of final energy demand by mid-century.[2] Reaching net zero by 2050 will require replacing these fuels with zero-carbon alternatives like hydrogen and ammonia. These zero-carbon fuels will be used to decarbonize hard-to-electrify sectors such as marine shipping, heavy-duty trucking, high temperature industrial process heating, ironmaking, long-duration energy storage, and aviation. To do so, the International Energy Agency ("IEA") projects that the world would require roughly 5 times the amount of hydrogen in 2050 than what was produced in 2020 (about 530 Mt hydrogen by 2050, compared to about 90 Mt produced globally in 2020).[3] The Regional Clean Hydrogen Hubs program established in the BIL is an impactful step for the U.S. to help meet this challenge and produce low-emissions hydrogen. The program will also help to break the collective action problem of clean hydrogen infrastructure (that neither the supplier nor end-user wants to be the first mover until there's ample supply and demand in place) by supporting the full value chain and the development of fully functional regional economies.

Beyond needing more infrastructure, clean hydrogen is also costly to produce compared to high-emissions hydrogen. Cost parity between the two will be the catalyst to more widespread

[2] International Energy Agency, Net Zero by 2050: A Roadmap for the Global Energy Sector (May 2021), https://www.iea.org/reports/net-zero-by-2050.
[3] International Energy Agency, Global Hydrogen Review 2021 (Oct. 2021), https://www.iea.org/reports/global-hydrogen-review-2021.

adoption. While incentives like the hydrogen production tax credit in the Inflation Reduction Act can help, further research, development, and deployment will be the key levers in driving costs down. The Clean Hydrogen Research and Development program will be vital in addressing this techno-economic challenge.

Determining what constitutes "clean hydrogen production" is an important step in this process, because hydrogen will only be effective as a climate solution if it is produced with truly low greenhouse gas ("GHG") emissions. Rigorous lifecycle analyses ("LCAs") will be required to ensure low GHG emissions, and DOE has the responsibility to make sure that standardized methodologies and user-friendly tools are available for hydrogen producers to support this goal. CATF submits the following comments to DOE on the draft Clean Hydrogen Production Standard.

Part 1: Data and Values for Carbon Intensity

<u>*Question 1a:*</u> *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.*

CATF agrees that the parameters listed in the indicated DOE spreadsheet (namely: fugitive methane emissions; rate of carbon capture; share of clean energy within electricity consumption; CO_2 leak rate from CCS; and delivered hydrogen purity) are key lifecycle parameters that may vary in real-world deployment. As a result, when calculating hydrogen's GHG emissions intensity in accordance with the CHPS, these parameters should be addressed on a site-specific basis for individual projects wherever possible, reflecting specific developer decisions, commitments, and operations, rather than using generic factors. CATF's responses to specific parameters are in the accompanying attached spreadsheet.

CATF also recommends that DOE confer with the U.S Environmental Protection Agency ("EPA"), given their role as an emissions regulatory agency, regarding carbon intensities of various options of hydrogen and electricity production.

In addition, the global warming potential ("GWP") timeframe used can significantly impact the resulting GHG LCAs. Both GWP20 and GWP100 can be useful for climate mitigation planning, and GWP20 can help illustrate the impacts of short-lived climate pollutants like methane. To better understand potential tradeoffs and short- and long-term impacts, DOE should use 100-year GWPs for purposes of the CHPS; however, DOE should also request that hydrogen producers report on sensitivity analyses using 20-year GWPs for information gathering and more informed decision-making.

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

Figure 1 must be revised, because it excludes emissions arising from manufacturing and construction of the equipment used to produce primary energy and convert that energy to hydrogen. The Draft Guidance indicates that DOE plans to align its LCA for the CHPS with the Inflation Reduction Act's ("IRA") definition of "qualified clean hydrogen." IRA defines "qualified clean hydrogen" as "hydrogen which is produced through a process that results in a lifecycle greenhouse gas emissions rate of not greater than 4 kilograms of CO_2e per kilogram of hydrogen." 26 U.S.C. § 45V (c)(2)(A). In turn, IRA defines "lifecycle greenhouse gas emissions" as "include[ing] emissions through the point of productions… as determined under *the most recent* …GREET model…". *Id.* at (c)(1)(A) (emphasis added). Therefore, to properly align CHPS with IRA, DOE must rely on the most recent version of GREET.

On October 11, 2022, DOE's Argonne National Laboratory issued a new version of GREET, which added the capability to include upstream emissions from manufacturing and construction of the equipment for primary energy.[4] Figure 1 needs to include these emissions and the emissions from manufacturing and constructing the equipment used to convert energy into hydrogen. Not only does GREET include these emissions, but alignment with IRA, which uses GREET to develop the LCA boundaries for GHG emissions as noted above, also dictates their inclusion.

These emissions can be quite significant, especially for photovoltaic power. According to DOE, the lifecycle GHG emissions associated with manufacturing and installing photovoltaic modules are around 40 grams of CO_2e per kWh of electricity produced, although this will vary considerably with panel type and details of installation.[5] These emissions are particularly dependent on the operating capacity factor of the installation, which in turn depends on both the technology (e.g., use of tracking) and the location (e.g., Arizona compared to Vermont). An electrolyzer with electricity consumption of around 53 kWh per kilogram of hydrogen produced would result in more than 2 kilograms of CO_2e per kg of hydrogen produced.[6] These emissions have roughly the same magnitude as some estimates for the impact of methane emissions from natural gas supply chains tied to hydrogen made from steam methane reformers.[7] To support innovation and reward better-performing projects and technologies, these emissions should be

[4] Argonne National Laboratory, The Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model (Oct. 2022), https://greet.es.anl.gov/

[5] National Renewable Energy Laboratory, Life Cycle Greenhouse Gas Emissions from Solar Photovoltaics (2012), https://www.nrel.gov/docs/fy13osti/56487.pdf.

[6] Fraunhofer Institute for Solar Energy Systems, Cost Forecast for Low Temperature Electrolysis – Technology Driven Bottom-Up Prognosis for PEM and Alkaline Water Electrolysis Systems (Oct. 2021), https://www.ise.fraunhofer.de/en/press-media/press-releases/2022/towards-a-gw-industry-fraunhofer-ise-provides-a-deep-in-cost-analysis-for-water-electrolysis-systems.html

[7] National Energy Technology Laboratory, Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies (2022), https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf.

included in hydrogen GHG accounting protocols. Industries in the U.S. are poised to supply photovoltaic panels with far less embedded carbon if U.S. policy appropriately recognizes differentiated GHG performance for this sector.[8]

Separately, CATF also urges DOE to include the emissions from transporting hydrogen to its end-user in the CHPS methodology. GREET likewise includes these emissions. Figure 1 does not include the emissions associated with transporting hydrogen to the end user. Transportation can have a significant impact on the resulting life cycle emissions depending on the method used (compressed cylinders, pipeline, liquefaction, conversion to hydrogen carriers such as ammonia, etc.). Including the emissions from transportation of hydrogen would create a more rigorous and complete hydrogen LCA. This is how the GHG accounting is handled by the California Air Resources Board for the Low Carbon Fuel Standard. In that case, gaseous hydrogen transportation emissions add about 6% to the total computed carbon intensity.[9]

If transportation emissions are excluded, then DOE should clarify that it is not considering all "downstream" emissions. From Figure 1, the only downstream emissions that are being considered are from transporting and storing CO_2. DOE should specify that the LCA covers up to the point of hydrogen production ("well-to-gate") with the addition of emissions from transporting and storing the CO_2 captured in the production process.

<u>Question 1d:</u> *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?*

Best practices for quantification of CO_2 leakage and losses during geological CO_2 sequestration activities are required for recipients of income tax credits under section 45Q of the Internal Revenue Code. Those requirements were developed over many years and incorporate significant public-sector and private-sector stakeholder input, several EPA regulations, and methods of the International Standards Organization.[10] Geologic storage of CO_2 requires a Class VI well permit regulated under EPA's Underground Injection Control Program. Class VI wells have stringent requirements that are tailored specifically for ensuring the safety and permanence of CO_2 injection. 40 C.F.R. § 146.81 *et seq*. The Class VI rule has extensive requirements to ensure that wells used for permanent storage of carbon dioxide are appropriately sited, constructed, tested, monitored, funded, properly closed, and that the storage site is appropriately characterized. Developers that have received a Class VI permit are also required to report under subpart RR of the Greenhouse Gas Reporting Program ("GHGRP"). 40 C.F.R. § 98.440 *et seq*. The two programs work complementarily to ensure secure, permanent storage of CO_2 and provide monitoring and reporting that identifies and addresses any potential leakage risks and provides

[8] *See*, *e.g.*, Ultra Low-Carbon Solar Alliance, https://ultralowcarbonsolar.org/ (last visited Nov. 1, 2022).
[9] California Air Resources Board, CA-GREET3.0 Lookup Table Pathways: Technical Support Documentation 37 (2018), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut-doc.pdf.
[10] *See* 86 Fed. Reg. 4728 (codifying 1 C.F.R. § 1.45Q-0 – 5)

public transparency. Under subpart RR, facilities are required to develop and implement a monitoring, reporting, and verification ("MRV") plan that is approved by EPA. CATF recommends that for purposes of evaluating a project's potential or actual sequestration-related CO_2 emissions under the CHPS, DOE assume negligible CO_2 leaks and losses over the geological CO_2 sequestration lifecycle unless a case-specific evaluation by DOE using the relevant IRS procedures determines a different value is more appropriate. Best practices for monitoring CO_2 injected into geologic formations are dependent on site-specific geology, and specific monitoring techniques should be considered on a case-by-case basis.

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

It is important to acknowledge hydrogen's indirect climate impact. However, these discussions must be conducted while keeping in mind the carbon-intensive processes that hydrogen will replace. Hydrogen can—and most likely will—play a vital role[11] in decarbonizing harder to electrify sectors such as heavy-duty trucking,[12] shipping,[13] and aviation[14] as a direct fuel or as a feedstock for a low-carbon fuel. Understanding that hydrogen's efficacy as a climate solution can be reduced by leaks underscores the importance of establishing robust leak detection and prevention programs. Combating leaks during the design phase for greenfield projects could make this issue easier to address.

To better assess the risk of hydrogen's indirect warming impact, there must be more robust real-world emission data across the supply chain and on the efficacy of leak detection programs. Current available emission data mainly consists of estimates regarding leak percentages. Given that there are many ways to produce, transport, and use hydrogen, it is important to assess these emission rates across each permutation. Emission data should include leaks; venting from start-up, shutdown, and maintenance; and hydrogen-slip from incomplete combustion or reaction. Regarding leak detection methods, a report from Columbia's School of International and Public Affairs ("SIPA") detailed the existing detection, monitoring, and prevention technologies.[15]

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[11] Jose M Bermudez, Stavroula Evangelopoulou & Francesco Pavan, Int'l Energy Agency, Hydrogen Tracking Report (Sept. 2022), https://www.iea.org/reports/hydrogen.
[12] Tom Walker, Why the Future of Long-Haul Heavy Trucking Probably Includes a lot of Hydrogen, Clean Air Task Force (May 21, 2021), https://www.catf.us/2021/05/why-the-future-of-long-haul-heavy-trucking-probably-includes-a-lot-of-hydrogen/.
[13] Mike Fowler et al., Clean Air Task Force, Bridging the Gap: How Nuclear-Derived Zero-Carbon Fuels Can Help Decarbonize Marine Shipping (2021), https://cdn.catf.us/wp-content/uploads/2021/08/21092159/NuclearZCFMarineShipping.pdf.
[14] Na'im Merchant et al., Clean Air Task Force, Decarbonizing Aviation: Challenges and Opportunities for Emerging Fuels (2022), https://cdn.catf.us/wp-content/uploads/2022/09/13101935/decarbonizing-aviation.pdf.
[15] Zhiyuan Fan et al., Columbia Center on Global Energy Policy, Hydrogen Leakage: A Potential Risk for the Hydrogen Economy (2022), https://www.energypolicy.columbia.edu/research/commentary/hydrogen-leakage-potential-risk-hydrogen-economy#:~:text=The%20leakage%20rate%20stands%20between,%242%2Fkg%2DH2.

While the report concludes that most technologies still require significant R&D—a conclusion CATF agrees with—it would also be valuable to understand what emission rates could be achieved with a robust hydrogen leak detection program built out of existing mitigation solutions. These solutions would not only include hydrogen detection technologies such as Nitto's hydrogen detection tape used by NASA, but also leak detection technologies available for gas-based operations as a whole.[16]

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

Captured CO_2 streams associated with the production of hydrogen (e.g., at methane reforming facilities that utilize carbon capture) should still be included as an emission for the GHG intensity of the hydrogen, unless that captured CO_2 is permanently sequestered.

Part 2: Methodology

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

As discussed in detail above, lifecycle accounting for hydrogen production should include emissions associated with manufacturing and construction of primary energy production and energy conversion systems, including photovoltaic panels, batteries, nuclear power stations, and geological sequestration sites. Including the emissions embodied in this infrastructure raises special challenges in lifecycle analyses, such as the predicted lifetime total production of each asset, and these emissions are excluded from IPHE and other schemes. DOE needs to address this omission, however, even if imperfectly at first.

Another useful framework is the European Commission's proposal for the revision of the EU's Renewable Energy Directive 2018/2011 ("REDII"),[17] which includes a GHG methodology for Renewable Fuels of Non-Biological Origin (RFNBO), covering renewable hydrogen and Recycled Carbon Fuels (RCF).

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[16] Nitto Hydrogen Detection Tape, https://nittodetectiontape.com/products/pc/Hydrogen-Detection-Tape-5p3.htm (last visited Nov. 1, 2022).

[17] *Proposal for a Directive of the European Parliament and of the Council amending Directive (EU) 2018/2001 of the European Parliament and of the Council, Regulation (EU) 2018/1999 of the European Parliament and of the Council and Directive 98/70/EC of the European Parliament and of the Council as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652*, COM (2021) 557 final (Jul. 14, 2021).

<u>Question 2b:</u> 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?

CATF urges that no biogenic resources be presumed as having net zero or negative CO_2 emissions without careful analysis of lifecycle emissions as prescribed in the IRA. Any feedstock from land-intensive sources, even if deemed waste products, should be evaluated as to their direct and indirect land use impacts. We also note that it is important to quantify leaks and other sources of emissions from the supply chain for biogenic methane, just as it is important to do so for natural gas methane.

<u>Question 2c:</u> 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?

CATF recommends the following approach used in the European Commission's proposal for the revision of the EU's Renewable Energy Directive 2018/2011 (REDII) (delegated act specifying a methodology for assessing GHG emissions savings from RFNBOs and RCFs):

- Where the process allows for changing the ratio of the co-products produced, the allocation shall be done based on physical causality by determining the effect on the process' emissions of incrementing the output of just one co-product whilst keeping the other outputs constant.
- Where the ratio of the products is fixed and the co-products are all fuels, electricity or heat, the allocation shall be done by energy content. If the allocation concerns heat that is exported on an energy content basis, only the useful part of the heat may be considered.
- Where the ratio of the products is fixed and some co-products are materials not used for fuels, the allocation shall be done by the economic value of the co-products. The economic value considered shall be the average factory-gate value of the products over the last three years. If such data is not available, the value shall be estimated from commodity prices minus the cost of transport and storage.

Part 3: Implementation

<u>Question 3a:</u> *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?*

With respect to upstream methane emissions, CATF endorses the design criteria laid out by the Environmental Defense Fund ("EDF") for programs that would credibly address methane emissions.[18] Existing certification schemes and protocols that seek to address this issue (Veritas, OGMP 2.0, QMRV, etc.) may be able to satisfy these criteria. As specified in the EDF paper, programs should employ robust monitoring that includes:

- "a methodology informed by direct measurement across varying spatial and temporal scales and based on statistically representative samples";
- "a methodology which integrates and reconciles top-down and bottom-up measurement data to validate emissions estimates"; and
- "emissions estimates reported with associated uncertainty."

In addition to the above criteria, a measurement program should encompass a sufficiently large geographical area (e.g., all of an operator's assets in a given region or sub-basin). This is essential to avoid cherry-picking the lowest emitting sites without reflecting an operator's actual average leak rate. Please see the paper regarding criteria for companies seeking certification.

Any certification should also be independently verified by a credible third party. While measurement technology is improving, we are not yet in a world where we can have continuous monitors at every GHG emitting facility across the country. One solution is for operators to assume a national (or regional) average leak rate (based on top-down measurement studies), unless they can sufficiently prove that their leak/emission rate is lower.

See comments on 1d) regarding verification for downstream CO_2 sequestration emissions.

<u>Question 3b:</u> *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?*

It is essential for stakeholders to account for the fact that natural gas coming from different production basins, operators, and transportation pathways will have different amounts of upstream emissions. Because developers are purchasing large quantities of gas and will likely contract with producers (or midstream companies), developers can demand that the vendor

[18] Maureen Lackner & Kristina Mohlin, Env't Defense Fund, Certification of Natural Gas with Low Methane Emissions: Criteria for Credible Certification Programs (2022), https://blogs.edf.org/energyexchange/files/2022/05/EDF_Certification_White-Paper.pdf.

implement a measurement and verification program to quantify the upstream footprint of the gas. Sufficient large developers requiring low leak rates could be a strong incentive to encourage upstream companies to measure and reduce emissions.

<u>Question 3c:</u> *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?*

To ensure that the hydrogen produced through electrolysis is actually low carbon, the operation of the electrolyzer should not result in any additional emitting generation produced for either the electrolyzer or for the pre-existing electricity demand served by the grid. This is most easily achieved through directly connected, behind-the-meter zero-carbon electricity like renewables or nuclear that power the electrolyzer. While this is also possible for electrolyzers that consume grid electricity and use offsets like Energy Attribute Credits ("EACs"), the three criteria outlined below are necessary guardrails for ensuring that the hydrogen production results in emissions reductions.[19]

1. **Additionality:** This means that electrolytic hydrogen producers should be able to show that the low carbon electricity used by or claimed by the electrolyzer is *additional* to the quantity of low carbon electricity that would have otherwise been generated to serve other electric loads.
2. **Geography-matching:** Due to the challenges of producing zero-carbon electricity around the country and the limitations of transmission capabilities to bring that electricity where it is needed, the EACs (like Renewable Energy Credits, or RECs) should be purchased in the same region (most likely, the same ISO/RTO) as the electrolyzer operations so that the electricity generation and demand are occurring within the same region.
3. **Temporal-matching:** Finally, the electrolyzer should only be operated when additional low-carbon electricity generation is available. To be sure that hydrogen production has low GHG-intensity, the electricity consumed by the hydrogen production facility and the EACs procured should be matched on an hourly-basis. This requirement would ensure that there is clean electricity available at the times when the electrolyzer consumes electricity; otherwise, electrolyzers would increase demand on the grid when only higher-

[19] For additional context on the importance of these guardrails, *see* Armond Cohen, Clean Air Task Force, It's Time We Update Our Corporate Electricity Procurement Standards to Decarbonize the Electric Grid, (Aug. 17, 2022); and Wilson Ricks, Qingyu Xu & Jesse D. Jenkins, Enabling Grid-Based Hydrogen Production with Low Embodied Emissions in the United States (2022), https://zenodo.org/record/7183516#.Y2FaZOzMK3I.

emitting sources of generation are available and could result in much higher GHG-intensity than intended.

Meeting these three criteria is absolutely essential for a broad climate-technology deployment program like the hydrogen production tax credit, which rewards hydrogen producers for meeting stringent GHG-intensity standards. Given the significant deployment support of the hydrogen tax credit, these strict guardrails are both reasonable and necessary.

On the other hand, in the case of the hydrogen hub demonstration program and DOE's other hydrogen R&D programs, it may be appropriate for the Department to allow grid-connected electrolytic hydrogen producers to qualify for inclusion in a hydrogen hub or other programs without meeting the strict criteria outlined above. This softening of requirements may be reasonable because these DOE programs are focused on achieving the goals of large-scale, first-of-a-kind infrastructure demonstration projects. These demonstration projects have the potential to enable significant future emissions reductions through the demonstration of technical and economic viability of low-emissions hydrogen, the development of hydrogen infrastructure, and the commercialization of low-emissions hydrogen technologies. However, at an absolute minimum, CATF strongly urges that DOE disallow the use of "unbundled" RECs for all clean hydrogen programs (unless those unbundled RECs meet all three strict criteria outlined above of additionality, regional-matching, and hourly-matching). In addition, CATF encourages DOE to use the criteria above to compare the GHG-intensity of hydrogen hub proposals and give preference to projects that can meet these criteria for use of EACs, even if these criteria are not strict requirements.

EACs should also only be allowable for offsetting emissions from electricity (e.g., to offset emissions from the grid for a grid-connected electrolyzer, or to offset the electricity used in fossil-based hydrogen production processes). EACs should not be allowed for offsetting emissions from fuels (i.e., purchasing of RECs should not be able to outweigh emissions from natural gas feedstocks). Fossil-based hydrogen production processes should instead be encouraged to use high rates of carbon capture and storage to bring down their hydrogen's GHG intensity.

Finally, Renewable Thermal Credits (i.e., credits generated from renewable natural gas) should not be counted toward the GHG intensity of hydrogen production under any circumstances due to the significant uncertainties around the net climate impact of biogenic processes.

<u>Question 3d:</u> *What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0 kgCO2e/kgH2)?*

CATF does not expect significant hydrogen fuels production from existing reforming units in the U.S. and expects that such units may be subject to regulation by EPA in the future. If CHPS is applied to existing hydrogen reformers, investments including but not limited to CCS retrofits that carry considerable cost per unit will be required. This will increase hydrogen production costs by a significant amount.

CATF does not expect current hydrogen electrolyzers to have trouble meeting the proposed target if the electricity used is predominantly low carbon (e.g., renewable or nuclear energy). However, the issue in using predominantly wind or solar power is the intermittency of power supply compared to the grid. This directly impacts the capacity factor for the electrolyzer itself (how often the electrolyzer is onstream), which in turn affects how producers would have to price the hydrogen to recover the capital cost. Combining the capital recovery and the cost of electricity would give us a more holistic picture of the economic impacts of running electrolyzers solely on low carbon energy.

Consider an example: what are the impacts of running an electrolyzer solely on wind power versus using grid electricity in the U.S.? It usually takes around 53 kWh to produce 1 kg of hydrogen.[6] Prior to the COVID pandemic economic disruptions, the average wholesale price of electricity and the levelized cost of wind electricity in the U.S. were similar – around $35/MWh. At that electricity price, and assuming an average capacity factor for wind of 35%,[20] an electrolyzer with a CAPEX and installation cost at $900/kW, and a 9% capital recovery factor, using solely wind would result in a cost of $3.08 per kg of hydrogen. Running the electrolyzer on the grid at a higher capacity factor of 95% would result in a cost of $2.37 per kg of hydrogen. See the table below for this comparison.

Electricity Source	Electricity Price ($/MWh)	Installation Cost ($/kW)	Capital Recovery	Capacity Factor	H2 Unit cost ($/kg)
Wind	$35.00	$900.00	9%	35%	$3.08
Grid	$35.00	$900.00	9%	95%	$2.37

Table 1: Comparison of electrolytic hydrogen production costs ($/kg) between using wind and grid electricity

Overall, operating on grid electricity allows for a higher capacity factor and makes it cheaper to run by around 23%. The climate cost to using grid electricity is the much higher carbon intensity. At 919 $lbCO_2$/MWh average U.S. grid carbon intensity,[21] using grid power would result in electrolytic hydrogen with a carbon intensity of 22.1 $kgCO_2e/kgH_2$. If using a combination of wind and grid power in this example, no more than 18% of the total electricity could be grid electricity for the project to meet the proposed 4 $kgCO_2e/kgH_2$ target. Note that this discussion assumes an electrolyzer project could procure electricity at wholesale prices, and that LCOE is a reasonable proxy for costs of procuring wind power, although costs could be substantially[22] higher[23] for both.

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[20] U.S. Energy Information Administration , Electric Power Monthly: Table 6.07.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_07_b (last visited Nov. 7, 2022).

[21] U.S. Energy Information Agency, United States Electricity Profile 2019 (Nov. 2, 2020), https://www.eia.gov/electricity/state/archive/2019/unitedstates/.

[22] U.S. Energy Information Agency, Today in Energy: Solar photovoltaic generators receive higher electricity prices than other technologies (Oct. 9, 2020) https://www.eia.gov/todayinenergy/detail.php?id=45436.

[23] U.S. Energy Information Administrative, Electric Power Monthly: Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a (last visited Nov. 7, 2022).

Electrolyzer operators switching away from the grid would have to navigate this pricing gap. As technology advances and the cost of electrolyzers come down, the capital recovery becomes less impactful to the overall price. Cheaper wind, specifically anything cheaper than $20.00/MWh, or a more expensive grid would also help bridge the divide. Note that we ignored any potential price changes to low carbon electricity with the recent 45Y Clean Electricity Production Credit in the IRA. We also ignored changes to O&M by assuming that switching electricity sources would have a negligible impact on maintenance costs.[24]

Part 4: Additional Information

<u>Question 4a:</u> *Please provide any other information that DOE should consider related to this BIL provision if not already covered above.*

The BIL requires, among other things, that DOE determine within 5 years whether the CHPS should be adjusted below the current standard. *See* 42 U.S.C. § 16166(b)(2). By that time, the guardrails discussed above for use of EACs (geography-matching, hourly-matching, and additionality) should be requirements. In addition, by that time, if not currently, the LCA system boundary should include full upstream and downstream emissions, including manufacturing emissions from energy equipment and transportation emissions to move hydrogen to its end-user, respectively. Considering that additional scope of included emissions, the net effect may or may not be an actual reduction in the numerical threshold for the CHPS, but it would incorporate a fuller and more rigorous LCA. DOE should also begin stakeholder consultation on that adjustment as soon as possible, both to give ample time to gather and incorporate stakeholder feedback and allow for meaningful expert opinions to be shared, and so that revisions can be implemented even before the 5-year statutory limit.

DOE should use a consistent version of GREET (at least 2022 version to include key capabilities) to avoid any issues with updated versions and new methodologies or assumptions until the CHPS is updated. Once CHPS is updated, a newer version of GREET with new key assumptions—or another tool, if a better option becomes available—must be used. DOE should also ensure that GREET (or any subsequent tool) is free and publicly available, very user-friendly, and accessible. Creating a webtool hosted on the DOE website (in place of the current GREET options) could help achieve these goals. At a minimum, DOE should provide detailed, user-friendly guidance on how to use GREET, as well as specific and clear directives on key default assumptions and national averages to use if facility-specific data is not available. DOE could also create a clear, simple "quick-start" guidance document on GREET to help hydrogen developers get a quick understanding of how GREET works and allow them to determine whether their project might fit within the CHPS. Along with this document, DOE could also provide technical assistance support for users, through a help desk or frequent training sessions, to assist developers, users, and other stakeholders who may encounter challenges navigating GREET or any subsequent tool for abiding by the CHPS.

[24] For additional context on how to make electrolytic hydrogen cheaper, see Fraunhofer Institute for Solar Energy Systems, *supra*, note 6.

Finally, DOE should align the hydrogen hubs program and the CHPS with the IRS efforts on implementing the hydrogen tax credit to streamline the process for receiving federal support for clean hydrogen. In particular, DOE and IRS should use consistent lifecycle system boundaries for defining the hydrogen GHG LCA, which should include full upstream GHG emissions from the production of hydrogen. This will ensure that federal support for hydrogen results in the best possible outcome for climate mitigation.

Conclusion

DOE must develop a rigorous framework for measuring GHG emissions from hydrogen production to ensure that the hydrogen used to mitigate climate change is truly low emissions. The draft CHPS is a meaningful step in the right direction toward establishing this framework and signaling the Department's intention to prioritize low-emissions hydrogen development. CATF greatly appreciates the opportunity to comment on this draft CHPS and looks forward to continued engagement with DOE and others on the hydrogen hubs and related R&D programs to help catalyze efforts toward a national clean hydrogen economy.

Respectfully submitted,

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Parameter	Assumptions made in analysis supporting proposed targets within draft CHPS	Respondent feedback Regional or national average values achievable within next 5 years (i.e. by 2027)	Regional or national average values achievable in future years, and respective timescale	Rationale for estimates and any additional comments
Fugitive methane emissions	~1% of methane throughput between the point of natural gas drilling to the point of use is assumed to be released through fugitive emissions (e.g. during drilling process, transmission pipelines). This loss rate is estimated to reflect average fugitive methane emissions between natural gas plays across the U.S. and current steam methane reformers. The basis for this estimate is further described in GREET supporting documentation: https://greet.es.anl.gov/publication-update_ng_2021 In columns C-E, please provide feedback on the technical and economic feasiblity of this leak rate being accessible regionally or as a national average.	1% is a feasible, while modest, target if both the recently proposed EPA source performance standard updates and the Methane Emissions Reduction Program (MERP) are implemented in a timely fashion.	0.2% is an achievable target by 2030.	We don't agree that 1% is a fair estimate of the current national average for fugitive methane emissions. While bottom-up estimates certainly do show figures closer to 1% , top-down estimates suggest that the current national average may be closer to 2%. Super-emitters, often caused by abnormal process conditions, are the small number of emission sources that make up an outsized portion of total emissions; these are not captured in current inventories. Instead, 1% is a feasible, while modest, target should the EPA finalize and implement the recently proposed source performance standard updates. A more ambitious target as suggested by the Oil and Gas Climate Initiative would be 0.2%.* In large gas producing countries like Russia, Algeria, and the U.S., typical emissions rates reach 2%. Some countries like Libya, Iraq, and some oil-heavy fields in the U.S. even see typical emission rates around 6 to 8%. Lower methane loss rates between 0.003% and 1.3% were measured in Norwegian offshore oil and gas fields in 2019. And emissions of 0.4% have been measured in Northest Pennsylvania. *Note: The OGCI target is only for for upstream segments, which comprise all operations from exploration to production and gas processing (up to the first point of sale), including LNG liquefaction plants if located before the first point of sale. In the U.S., adding emissions from downstream segments would increase emissions by an additional 15-25%. See: OGCI Reporting Framework, https://www.ogci.com/wp-content/uploads/2022/10/OGCI-Reporting-Framework-2022-March-2022.docx. https://www.ogci.com/action-and-engagement/reducing-methane-emissions/#methane-target C. Bauer et al., "On the climate impacts of blue hydrogen production," Sustain. Energy Fuels, vol. 6, no. 1, pp. 66–75, 2022, doi: 10.1039/D1SE01508G. Foulds, 2022, "Quantification and assessment of methane emissions from offshore oil and gas facilities on the Norwegian continental shelf." https://acp.copernicus.org/articles/22/4303/2022/acp-22-4303-2022.pdf. NETL, "Continuous, Regional Methane Emissions Estimates in Northern Pennsylvania Gas Fields Using Atmospheric Inversions." https://netl.doe.gov/node/2334
Rate of carbon capture	~95% carbon capture at natural gas reforming facilities and gasification plants is assumed to be commercially deployable, and to enable one path to achieving the targets proposed in this draft guidance. In columns C-E, please provide feedback on the technical and economic feasiblity of this rate of carbon capture being deployed.			A ~95% carbon capture rate is a fair assumption for what is commercially deployable at reforming facilities and gasification plants.
Share of clean energy within electricity consumption	Use of predominantly clean energy (i.e. $\geq$85% clean energy, $\leq$ 15% U.S. grid mix) in electrolysis is expected to enable achievement of the lifecycle target proposed in this draft guidance. In columns C-E, please provide feedback on the techincal and economic feasibility of electrolyzers accessing this share of clean energy.			
CO2 leak rate from CCS	Leak rates of <1% from CO2 sequestration sites are assumed to be feasible today, and expected to enable achievement of the proposed targets in this draft guidance. In columns C-E, please provide feedback on the technical and economic feasiblity of this CO2 leak rate being achieved.			Leakage rates of less than 1% are supported by IPCC, 2005: "injecting CO2 into deep geological formations at carefully selected sites can store it underground for long periods of time: it is considered likely that 99% or more of the injected CO2 will be retained for 1000 years." Careful site selection and characterization is required under regulation, and it is reasonable to assume less than 1% leakage rate for at least 1000 years.
Other (e.g. pressure and purity conditions at output of hydrogen production facilities)	In analysis to inform the CHPS, systems were modeled to achieve hydrogen production with 99% purity and 3 MPa at the outlet.			