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United States Department of Energy
Office of Energy Efficiency & Renewable Energy
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Proposed Clean Hydrogen Production Standard:

Comments and Feedback from GTI Energy

To Whom It May Concern:

On behalf of GTI Energy, we respectfully submit the following comments to the Department of Energy's (DOE) Office of Energy Efficiency & Renewable Energy in response to DOE's initial proposal for a Clean Hydrogen Production Standard (CHPS), developed to meet the requirements of the Infrastructure Investment and Jobs Act of 2021, also known as the Bipartisan Infrastructure Law (BIL), Section 40315.

GTI Energy is a leading research and training organization that leverages the expertise of our trusted team of scientists, engineers, and industry partners to deliver impactful innovations needed for low-carbon, low-cost energy systems worldwide. We believe that incorporating clean hydrogen as an energy carrier can leverage the nation's existing energy infrastructure to achieve deep decarbonization of our economy and transition to a net-zero future. Hydrogen is flexible and able to draw on many pathways and energy sources for application. However, one of the missing factors for hydrogen is carbon intensity accounting as an enabler for market signals. Governments and organizations that have made ambitious climate pledges need an easy way to discover and compare low-carbon hydrogen solutions.

GTI Energy is working to answer that market need through several initiatives, most notably our partnership with S&P Global Commodity Insights, with technical support from the DOE's National Energy Technology Laboratory (NETL), to launch the Open Hydrogen Initiative in 2022. The Open Hydrogen Initiative (OHI) is an international coalition of over 30 participating organizations from industry, government, academia, coalition groups, and environmental NGOs with the mission of creating a harmonized methodology to vet the carbon intensity of hydrogen production at the facility level. In a bid for transparency and credibility, all the deliverables from OHI will be made open source and publicly available for integration and implementation across markets, corporate intelligence efforts, and policymaking. We hope that, through open learning and public-private collaboration, the OHI methodology can serve the Department of Energy and the U.S. government more broadly in its efforts to implement the Clean Hydrogen Production Standard (CHPS). Specifically, the OHI methodology will establish a globally accepted tool and corresponding set of protocols, giving market participants a consistent and credible framework for determining the carbon intensity of a given kilogram of hydrogen produced at a given facility. The OHI methodology will be made open-source for use by any party. To this end, OHI will stand ready to support CHPS implementation as complementing source material for any future development of the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model established by DOE's Argonne National Laboratory. The OHI team would welcome deeper collaboration with Argonne National Lab and the DOE on this topic. The feedback provided here

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is based on upon GTI Energy's deep understanding of GREET (especially the hydrogen production pathways in GREET – see hypec.gti.energy) and insights gained through engagement with industry and other stakeholders through OHI. **The feedback herein solely reflects the position of GTI Energy. NETL's role in the Open Hydrogen Initiative project does not represent or endorse the actions of the United States Government nor any agency thereof, expressed or implied, and does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions expressed by NETL and/or OHI do not necessarily state or reflect those of the United States Government or any agency thereof.**

We appreciate the opportunity to respond to the DOE's request for feedback pertaining to the proposed CHPS. We would welcome the opportunity to further engage with the DOE as the agency develops this important guidance. Thank you for your time and your consideration.

Sincerely,

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Derek Wissmiller, Head of Energy Systems Centers of Excellence
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1) Data and Values for Carbon Intensity

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

A single static value will always be incorrect when assessing the carbon intensity of individual hydrogen production at the facility level. Instead of attempting to identify a standard value, governments and market participants should be collaborating to develop agreed-upon structures and methodologies for identification of high-fidelity measured values representative of real-time operation and supply-chain characteristics. In doing so, carbon intensity calculations become reflective of the real-world operations of a single facility at a single point in time. This approach not only increases accuracy, but also creates a structure that incentivizes the rapidly growing industry to implement incremental, facility-level decarbonization solutions that would otherwise not be captured in a less granular approach.

B. Lifecycle analysis to develop the targets in this draft CHPS were developed using GREET. GREET contains default estimates of carbon intensity for parameters that are not likely to vary widely by deployments in the same region of the country (e.g., carbon intensity of regional grids, net emissions for biomass growth and production, avoided emissions from the use of waste-stream materials). In your opinion, 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?

Regional averages (both spatial and temporal averages) for carbon intensity parameters are insufficient for determining the carbon intensity of hydrogen production for a given facility. This is to say that there are very few values that are unlikely to vary meaningfully at a sub-regional level. If a facility pays a premium to source lower-carbon electricity or responsibly sourced natural gas, the model must factor this into the determination of the carbon intensity for the associated hydrogen production facility. Temporal granularity is also a very important parameter to capture in accounting for GHG emissions. The proposed methodology is far too tolerant of failing to capture this level of granularity.

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

Figure 1 does not seem to include downstream hydrogen compression for transport. This is appropriate given this is a producer's tax credit. Additionally, the emissions from compression for

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transport and refueling station and refueling station cooling are not controlled by hydrogen producer and thus should be outside of scope for the CHPS.

However, footnote 11 on page 5 states "In the CHPS, the lifecycle target corresponds to a system boundary that terminates at the point at which hydrogen is delivered for end use." Thus, there is inconsistency between Figure 1 of the CHPS guidance, and footnote 11 on page 5.

The language in footnote 11 on page 5 also implies that GREET will be used for CHPS. The default calculations in GREET also include emissions associated with compression of hydrogen up to high pressures (14,000 psi) for hydrogen vehicle filling stations. Footnote 11 on page 5 appears to indicate that these emissions won't be included, however, it's not clear how this will be accomplished given that these emissions are embedded in GREET (excel version 2021).

In general, the CHPS guidance is murky on the definition of LCA scope boundary. The table below defines five possible cases for which the scope could be defined. Subsequent tables in the report (Tables 2-5) reference these cases and show the impact of these different boundary assumptions on the results.

Table 1. Potential cases that could be used to define the LCA analysis boundary for CHPS.

	Upstream of Hydrogen Plant			Hydrogen Plant	Downstream of Hydrogen Plant	
	Construction of Infrastructure and Equipment	Production of Energy Feedstocks	Transportation of Energy Feedstocks to Hydrogen Production Facilities	Production of Hydrogen	Transportation of Hydrogen to Refueling Stations	Compression for Refueling of Hydrogen Vehicles
Case 1	Not Included	Included	Included	Included	Not Included	Not Included
Case 2	Not Included	Included	Included	Included	Included	Not Included
Case 3	Not Included	Included	Included	Included	Included	Included
Case 4	Included	Included	Included	Included	Included	Included
Case 5	Included	Included	Included	Included	Not Included	Not Included

In summary, our perspectives are as follows:

- We interpret that the CHPS guidance is recommending the scope to be Case 2. We disagree with this recommendation, as emissions associated with downstream transportation of hydrogen should not be included. Hydrogen producers are likely to be a separate business entity from midstream hydrogen transporters, and as such, the CHPS should be solely applied to the producer of the hydrogen, not the transporter of the

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hydrogen. In addition, CHPS' usage of Case 2 is not in alignment with IPHE guidance recommending the exclusion of downstream hydrogen transport.

- The Open Hydrogen Initiative has conducted extensive stakeholder engagement via our industry coalition over the last 9 months. Feedback from stakeholders suggests infrastructure emissions should be included where it contributes meaningful to a levelized carbon intensity and where it is practical to include. Please review the delta between Case 3 and Case 4 in Tables 2 & 3 for an example.

Given that the CHPS guidance implies that GREET will be used, and that emissions associated with downstream hydrogen transportation will be included, there is an important methodological issue to be raised. GREET performs calculations assuming the same electricity source for all steps of the process. That is, the electricity used for hydrogen production is the same electricity used for downstream hydrogen transportation. In real world implementation, the electricity used for hydrogen production (such as a solar), is very likely to be different than the electricity used for downstream hydrogen transportation (such as the US grid mix). This has meaningful impact on the results (see Table 2 versus Table 3 below). GREET is not currently capable of readily performing such calculations.

As DOE develops methodologies that are both practical and credible, we'd welcome DOE's active engagement with industry-forward coalitions like the Open Hydrogen Initiative. In general, a final decision on the boundary of the analysis should be made with transparency, openness, and collaboration with stakeholders.

D. 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?

Fugitive hydrogen emissions should be accounted for in the CHPS guidance framework. Reputable organizations that convene stakeholders and experts around this topic (e.g., IPCC) should be used to inform these guidelines.

At present, the energy community currently lacks a well-vetted understanding of where and to what extent hydrogen leakage occurs in the production supply chain. A comprehensive methodological assessment of hydrogen production systems at the unit process level should be supported by the US DOE to improve understanding on this front. Our recommendations are for the DOE to:

a. Follow IPCC guidelines;

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b. Work in coordination with R&D coalitions to support this necessary development of hydrogen as a decarbonization solution.
c. Assess existing hydrogen production supply chain at the unit-process level to understand emissions hotspots; and
d. Improve technology and deployment of hydrogen sensors.

Our understanding of the magnitude of fugitive hydrogen emissions and their associated impacts on global warming are sure to evolve over the coming years. This highlights the need for the CHPS implementation framework to be defined with relevant structures and processes to facilitate evolution in methodology and approach to accommodate new technologies and knowledge.

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

CO2 utilization is not relevant to a CHPS and should not be included in the lifecycle standard for hydrogen production. CO2 utilization is an important topic, however. Independent of CHPS, DOE should proactively seek to support efforts aimed at convening stakeholders and market participants to establish transparent and consistent frameworks for GHG accounting in CO2 utilization.

2) Methodology

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

ISO and IPHE are good standards to serve as a foundation for carbon accounting methodologies. They do not, however, provide the level of detail needed to support hydrogen market transactions. General system boundaries are specified but it is not clear what kind of unit processes are included or excluded within these boundaries. All stages in an LCA are defined in general terms and this can introduce uncertainty. DOE must ensure that stakeholders with real practice in the field are included in conversations to define those standards, as these practitioners will be able to provide a higher level of details on what needs to be included in the accounting framework. Furthermore, the IPHE framework does not provide guidance on data quality and confidence. Quantification of data quality is a prerequisite to a high-fidelity asset-level carbon intensity calculation.

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GHG reporting responsibilities are often segmented in a scope classification system, including Scope 1 emissions, Scope 2 emissions, and Scope 3 emissions. However, these scope emissions do not necessarily reflect the emissions coming from a specific stage in the LCA.

Moreover, the classification recommended for reporting within the ISO frameworks does not always align well with the LCA stages of a product. This can lead to confusion. It is critical that the scope and boundary of the LCA analysis be made clear (see Tables 1-5 in this document). Further, we recommend that stakeholders should be engaged in defining a consist set of frameworks and definitions for the LCA boundary, as we are doing under the Open Hydrogen Initiative.

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

Greater consistency is needed in the treatment of waste between various LCA standards, as well as within individual standards, and greater stakeholder engagement is needed to drive towards such consistency. At present, there is a lack of consistency with waste considered to be zero emission in some LCA frameworks, versus being accounted as a negative emission feedstock when considering consequential effects (avoidance) in other LCA frameworks. For example, in GREET, the following three wastes are treated differently: manure, waste natural gas, and petroleum coke (pet-coke).

a. Manure is a waste from the agricultural industry. Manure is currently treated differently depending on whether the LCA is being conducted for meat/dairy production versus renewable natural gas (RNG) production. In the LCA of meat or dairy, manure is treated as a waste stream with an emission factor of zero. However, if the manure is left to decompose in ponds, it will emit methane gas (scope 3). As such, an LCA of RNG production from waste manure yields a negative credit for the avoided emissions compared to leaving it in ponds. This is a demonstration in incongruencies that should be addressed in concert with a diverse set of participants and energy community stakeholders.

b. Oil-producing wells often have associated natural gas that is either vented or flared, making it a waste. In the LCA of oil production, it is a positive emission. In contrast, GREET does not treat it as a waste with negative consequential emissions when the

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natural gas is utilized (e.g., reforming to H2, used as fuel), even though it is avoiding venting or flaring emissions.

c. Pet-coke is a refinery waste. In GREET, it is treated as waste. Pet-coke is, however, oftentimes combusted for power generation. If it were gasified to hydrogen, it would avoid the combustion emissions, but it is unclear if GREET considers this consequential effect.

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

Co-product treatment can be done through displacement (e.g., substitution) or allocation (energy allocation, mass displacement, or market value). Each of these approaches can lead to very different results. There are advantages and disadvantages to each of these approaches – no single approach is universally favored. The approach used should be selected in a manner that (1) works most suitably for evaluating facility level analysis, and (2) is harmonized and consistent with stakeholder buy-in.

Choices made regarding co-product allocation can significantly impact results as shown in the GREET (v2021) results for steam methane reforming (SMR) for different allocation methods of steam in the following figure.

Figure 1. Carbon Intensity (kgCO2e/kgH2) of hydrogen production via steam methane reforming, as reported in GREET (v2021) for differing co-product allocation methods.

	kgCO2e/kgH2
Displacement of steam coproduction	11.20
Energy allocation	11.65
Market allocation	13.75

General comments regarding common co-product allocation methods are as follows:

a. Energy allocation is simplest when all products are energy products. Mass displacement is often favorable to H_2 under current default assumptions in GREET. Market is the most uncertain as value ratios can change in time with market fluctuations.
b. In system expansion with displacement there's many assumptions about the emission factors of the product that is substituted. Options need to be offered based on stakeholder input.

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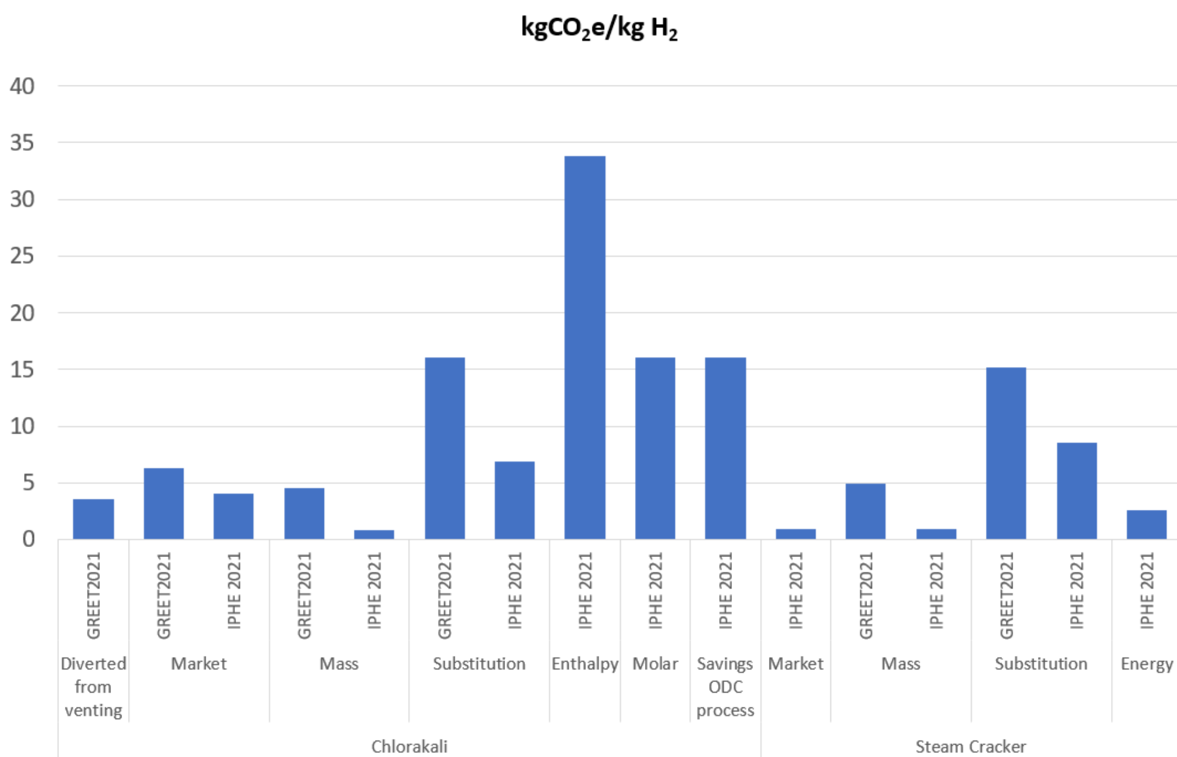
D. **How should GHG emissions be allocated to hydrogen that is a by-product, such as in chlor-alkali production, petrochemical cracking, or other industrial processes? How is by-product hydrogen from these processes typically handled (e.g., venting, flaring, burning onsite for heat and power)?**

These important methodological choices can greatly influence emission results, as illustrated by the figure below. Even when there is agreement on treatment methodology, certain assumptions might significantly impact the results. This is the case of choice of substituted product in a displacement methodology. More consistency in methodology is needed, as well as more transparency and options in terms of assumptions. Stakeholder engagement is key.

Figure 2. Carbon Intensity (kgCO2e/kgH2) of hydrogen production as by-product of chlor-alkali and steam cracker processes, calculated under different methodologies in GREET2021 and as reported in IPHE document "Methodology for Determining the Greenhouse Gas Emissions Associated with the Production of Hydrogen".



Different standards seem to be recommending different approaches. Examples from the May 2021 report "Options for a UK low carbon hydrogen standard" include (verbatim):

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a. "Value-based allocation (averaging the last 5 years of Eurostat data) is being used in CertifHy as an interim solution, with agreement to use the ODC process as a benchmark as soon as robust data are available."

b. "By contrast, TÜV SÜD uses an enthalpy-based allocation or allows benchmarking against the ODC process (where third-party validated data are available). The RTFO is yet to consider issuing certificates to renewable chlor-alkali by-product hydrogen."

c. "In line with RED, the RTFO has to date chosen to use a system expansion approach for combined heat & power (CHP) units, awarding a CHP credit for the avoided emissions compared to generating the same heat & power separately – although DfT are consulting on removing this CHP credit and returning to an energy allocation approach."

d. "The RED and RTFO also choose to allocate nil impacts to biogenic residues/wastes (only allocating emissions to products and co-products), to simplify GHG emissions calculations and prevent there being an incentive to produce more residues/wastes."

e. "The LCFS generally uses energy allocation for energy co-products, but for processes producing a mix of energy and non-energy co-products, a displacement (system expansion) method is often chosen for the non-energy products."

f. "However, the choice of the most appropriate allocation option for each certified route is made by CARB, and the overall philosophy is to make conservative allocation choices that allocate more emissions to the certified fuel."

IPHE guidelines seem to recommend energy allocation for steam cracker and displacement for chlor-alkali processes. Since IPHE guidelines are referenced throughout the DOE CHPS guidance, it seems they would also be used for allocation in the H2 as by-product cases. However, there is no apparent reason to not use the same approach in both cases.

In the case of chlor-alkali process, hydrogen is usually sold as chemical feed or as a fuel to produce steam or electricity. In this case, the IPHE recommends displacement since there is diversity in the products that can be substituted. For steam crackers, energy allocation is the method recommended though substitution is also possible. In steam crackers, co-product hydrogen is usually burned for heat in the facility. If this co-product hydrogen is sold into merchant markets, natural gas will need to be burned to produce heat to backfill for that hydrogen. If the steam cracker hydrogen is allocated by energy, it is ignoring this change in behavior and potential increase in net GHG emissions. There is a clear counterfactual, which justifies the substitution approach in the steam cracker case. There is no reason both cases should not be treated the same way. A transparent and consistent approach needs to be applied and clearly communicated.

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3) Implementation

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

DOE should adopt protocols that outline best practices in data reporting, monitoring, verifying, tracking, and traceability. These protocols should be written in concert with the industry, mindful of existing reporting guidelines, emissions hotspots, and emissions blind spots. Monitoring GHG emissions is likely to require novel equipment and reporting guidelines. Emissions should be reported on a per-kilogram hydrogen basis. Third-party verification companies have a positive track record of verifying reported emissions and ensuring deployment demonstrably aids achievement of the CHPS. DOE should confirm that there is no transaction, financial or otherwise, taking place between the verifier and the assets owner or operator, to ensure impartiality and avoid any conflict of interest.

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

Ultimately, CHPS should be linked to asset-specific characteristics of a given hydrogen production facility. That is, the overall carbon intensity assessment for a given hydrogen production facility should be based on the specific attributes of the source energy and feedstocks that are utilized by that hydrogen production facility and the operational parameters of the facility and its upstream supply-chain, rather than average values for source energy and feedstocks in a given region. For example, if certified or responsibly sourced natural gas is utilized, this should be taken into account when evaluating the carbon intensity of a given hydrogen production facility.

Frameworks for tracking the associated methane emissions and carbon intensity for natural gas value chains are currently in development (Veritas, OGMP, etc.). The CHPS carbon intensity evaluation methodology should be forward-looking and capable of accommodating information from these impending frameworks. In general, greater transparency in GHG data quality, tracking, and traceability is needed throughout and across energy value chains, both domestically and globally, to establish clarity in GHG accounting frameworks to underpin low-carbon energy markets.

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

Yes, renewable energy credits, power purchase agreements, and similar market structures should be allowed when characterizing the intensity of electricity emissions for hydrogen production. Production facilities may not always be located adjacent to renewable sources of energy. For example, it may be easier to transmit power to an electrolyzer sited at the point of hydrogen demand than to transport hydrogen from an electrolyzer sited at a renewable energy facility to the point of hydrogen demand.

There are multiple private companies that can calculate the carbon intensity of electricity being sent to the facility at every moment and can ensure that the power is indeed carbon-free. These services are already helping large companies like Microsoft and Google achieve their 24/7 renewable energy goals. In this way, hydrogen production facilities can be operated on carbon-free power throughout the day, even when the sun is not shining, or the wind is not blowing. Facilities that use market structures to source carbon-free power should be required to hire the verification companies themselves in order to be eligible for CHPS.

Care must be taken in providing guiderails on how the industry uses financial mechanisms to indicate decarbonization. Voluntary carbon markets, offsets, and some abatement programs are still maturing. This evolution should be taken into account when relying on these mechanisms to imply decarbonization, especially in how it relates to permanence, additionality, and fidelity.

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

As discussed earlier in our response in this document in relation to Table 1 above, the CHPS guidance is unclear regarding the scope of the LCA analysis that will be applied. Tables 2-5 below show the impact of the boundary definition case (see Table 1) on the carbon intensity for electrolysis, steam methane reforming, and biomass gasification. The results vary considerably depending on the system boundary for the same technology under the same assumptions and operating conditions. In some cases, this leads to results which exceed 4.0 kgCO2e/kgH2.

Table 2. Electrolysis carbon intensity (kgCO2e/kgH2) for different electricity sources. Results based on GREET (version excel 2021).

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Electricity Source Upstream of Hydrogen Plant	Electricity Source for Hydrogen Plant	Electricity Source Downstream of Hydrogen Plant	Case 1	Case 2	Case 3	Case 4
US Grid Mix	US Grid Mix	US Grid Mix	21.94	22.43	23.93	24.29
Solar Only	Solar Only	Solar Only	0.00	0.00	0.00	2.51
Wind Only	Wind Only	Wind Only	0.00	0.00	0.00	0.33
Nuclear Only	Nuclear Only	Nuclear Only	0.10	0.11	0.11	0.14

Table 3. Electrolysis carbon intensity (kgCO2e/kgH2) for different electricity sources for upstream and at hydrogen plant and US grid mix for downstream of hydrogen plant, which is likely to be a realistic scenario (it is not likely that 100% renewable energy could be used for downstream hydrogen transportation, for example). Results are based on GREET (version excel 2021) and GTI Energy calculations that are consistent with GREET LCA methodology. These GTI Energy calculations were performed because GREET is not capable of evaluating two different electricity sources for different portions of the overall hydrogen production pathway (see discussion under Table 1 above).

Electricity Source Upstream of Hydrogen Plant	Electricity Source for Hydrogen Plant	Electricity Source Downstream of Hydrogen Plant	Case 1	Case 2	Case 3	Case 4
US Mix	US Mix	US Grid Mix	21.94	22.43	23.93	24.29
Solar Only	Solar Only	US Grid Mix	0.00	0.49	1.99	4.50
Wind Only	Wind Only	US Grid Mix	0.00	0.49	1.99	2.32
Nuclear Only	Nuclear Only	US Grid Mix	0.10	0.59	2.09	2.11

Table 4. Steam methane reforming carbon intensity (kgCO2e/kgH2) for different carbon capture rates and electricity sources. Results based on GREET (version excel 2021).

Carbon Capture Rate	Electricity Source	Case 1	Case 2	Case 3	Case 4
85%	US Grid Mix	3.50	3.99	5.47	5.71
100%	US Grid Mix	2.18	2.67	4.16	4.39
85%	Wind	2.83	2.83	2.83	3.05
100%	Wind	1.44	1.44	1.44	1.67

Table 5. Biomass gasification carbon intensity (kgCO2e/kgH2) for different electricity sources. Results based on GREET (version excel 2021).

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Carbon Capture Rate	Electricity Source	Case 1	Case 2	Case 3	Case 4
0%	US Grid Mix	1.53	2.02	3.52	4.32
0%	Wind	1.26	1.26	1.26	2.07

GREET (v2021) results indicate that even with 100% carbon capture and sequestration, it is not possible for steam methane reforming (SMR) to achieve the 4.0 kgCO2e/kgH2 target if average US grid electricity is used for a system boundary according to Case 3 (see Table 1). For a system boundary defined according to Case 2 (see Table 1), a carbon capture rate of 85% or higher is required.

Electrolysis is a technology that could conceivably achieve the 4.0 kgCO2e/kgH2 target only if low-carbon electricity is available. If using the existing US mix (EF = 440 gCO_2e/kWh), the current electrolysis technology defined in GREET2021 gives a carbon intensity of 24 $kgCO_2e/kg$ H_2. To achieve the 4.0 kgCO2e/kgH2 target, the electricity needs to have an emission factor of 74 gCO_2e/kWh or lower (assuming Case 3 system boundary). This low electricity generation emission factor will have higher cost in comparison to current electric rates.

NETL recently released a study comparing costs and emissions associated with various fossil-based hydrogen production pathways. Their conclusion was that gasification of a combined coal and biomass feed and CCS of CO_2 produced in the gasifier resulted in net-negative emissions. Their calculations estimated a carbon intensity of -1.0 kg CO_2e/kg H_2, and the hydrogen cost is \$3.64/kg H_2.

The inclusion of fugitive hydrogen as an indirect GHG could send some production facilities above the 4 kgCO2e/kgH2 benchmark. This could lead to additional cost to achieve the 4 kgCO2e/kgH2 target.

4) Additional Information

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

Proper implementation of a clean hydrogen production standard requires highly transparent, collaboratively developed methodologies. Importantly, these methodologies need to assess carbon intensity at the asset/facility level. Usage of pathway level averages, regional averages,

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and literature values should be minimized, being replaced with measured, real-time values whenever possible. We also recommend broad sector-level engagement in the development of these methodologies, ensuring that practical, real-world experience is brought to bear. A focus on asset-level operational characteristics and broad sector-level engagement in development will help avoid delayed reactions and the associated catastrophic climate impacts associated with emissions oversights, recently highlighted by fugitive methane emissions.

We believe the following issues were not addressed in this guidance:

a. Will a given hydrogen production facility be able to calculate its carbon intensity based on facility-specific measurements of its energy consumption (e.g. electricity, natural gas, biomass) per unit of hydrogen produced? This is a fundamental parameter impacting the hydrogen production facilities' carbon intensity.

b. Will a given hydrogen production facility employing carbon capture be able to calculate its carbon intensity based on facility-specific measurements of its carbon capture rate? This is a fundamental parameter impacting the hydrogen production facilities' carbon intensity.

c. Will a given hydrogen production facility be able to calculate its carbon intensity based on facility-specific characterization of its specific energy and feedstock sources? That is, if responsibly sourced gas or biomass, or low-carbon grid electricity is purchased, will the hydrogen production facility be able to use values specific to where it gets its energy and feedstock from in its calculations? These are fundamental parameters impacting the hydrogen production facilities carbon intensity.

d. The CHPS guidance implies that GREET will be used as the tool for evaluation (see footnote 11 of pg. 14). Will the GREET excel version or GREET NET be used to perform the CHPS calculations? There are differences in functionality between these two tools.

e. The CHPS guidance implies that GREET will be used as the tool for evaluation (see footnote 11 of pg. 14). In our feedback, we have stressed the need for asset specific information, rather than average and/or representative values. To further highlight this point, consider the following. GREET version 2022 was just released on October 11, 2022. The GREET version 2022 results for the carbon intensity of hydrogen production differ from the GREET version 2021 results for several pathways and/or technologies. These differences are presumably the result of changes in default average and/or represented values embedded within GREET. It is not clear whether these default values can be readily accessed by a GREET user. Further, if they are readily accessible, it is not clear whether a user will be allowed to adjust these values as relevant for evaluation a

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given hydrogen production facility under the CHPS. The guidance does not provide sufficient clarity on these topics. Further, the guidance does not provide clarity as to the process for which changes in such default values would be defined, approved, and implemented into GREET.

f. The inclusion of fugitive hydrogen as an indirect GHG could send some production facilities above the 4 kgCO2e/kgH2 benchmark. Our understanding of the magnitude of fugitive hydrogen emissions and their associated impacts on global warming are sure to evolve over the coming years. This highlights the need for the CHPS implementation framework to be defined with relevant structures and processes to facilitate evolution in methodology and approach to accommodate new technologies and knowledge. The guidance does not speak to these issues.

g. Will embedded emissions (e.g., emissions associated with building infrastructure and equipment) be included in the analysis? If so, specifically what infrastructure emissions will be included and what infrastructure emissions will be omitted? When infrastructure-related emissions are included, solar powered electrolysis results in 2.51 $kgCO_2e/kgH_2$. This is a significant contribution. IPHE guidance seems to omit infrastructure emissions on the premise that they are minor. This is incorrect. Omission of infrastructure emissions would overlook a significant source of GHGs.

h. Generally, we believe that the system boundary for emissions calculations should stop at the plant gate with a functional unit of hydrogen (predefined temperature, purity, and pressure), excluding post-production processing that goes beyond this functional unit (like liquefaction or additional compression). This allows for improved like-to-like comparison, assists with hydrogen market formation through more consistent spot-market structures, and avoid penalizing producers for extraordinary delivered-state configurations required by hydrogen consumers.

i. Will the emissions from energy use for CO_2 injection and leakage from geologic storage be included in GREET? GREET2021 seems to include only emissions from the CO_2 capture alone, not the injection energy emissions, or CO_2 leakage over time.

j. Will any Carbon Capture and Utilization (CCU) cases be considered by the CHPS. How will the CHPS account for the emissions savings and recycling in cases where the CO2 is captured and utilized?

k. The CHPS guidance implies that GREET will be used as the tool for evaluation (see footnote 11 of pg. 14). GREET does not currently include a comprehensive set of hydrogen production pathways. For example, GREET does not include pathways for methane pyrolysis, partial oxidation (POX), and autothermal reforming (ATR), all

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technologies for which commercial plants are in operation or being developed. How will these technologies be evaluated under CHPS?

l. Will the CHPS incorporate a methodology to account for variability in data quality and confidence? The reliability and representativeness of real-time measured data far outweighs that of industry-average or literature data. The CHPS should include a framework to 1) attribute a confidence interval based on the net quality of data used for asset-level calculations, and 2) use this confidence interval as an incentive for the industry to gravitate towards the usage of real-world measured data vs relying on literature and average values.

m. The CHPS guidance is not clear on the greenhouse gases that will be evaluated beyond CO_2 and CH_4. In particular, CHPS should provide guidance on accounting of fugitive hydrogen and N_2O.

n. The CHPS guidance is not clear on whether GWP-100 or GWP-20 will be used to underscore the calculation of global warming potential (GWP). Furthermore, CHPS documentation is not clear on whether EPA or IPCC GWP values will be used.