Clean Hydrogen Production Standard (CHPS)

Comments

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U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance

Summary

This draft guidance document contains the U.S. Department of Energy's (DOE's) initial proposal for a Clean Hydrogen Production Standard (CHPS), developed to meet the requirements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.

The CHPS is not a regulatory standard, and DOE may not necessarily require future funded activities to achieve the standard. However, hydrogen hubs funded in support of the BIL will be required to "demonstrably aid achievement" of the CHPS by mitigating emissions across the supply chain to the greatest extent possible (e.g., by employing high rates of carbon capture, using low-carbon electricity, or mitigating upstream methane emissions). Future DOE funding opportunity announcements will further describe merit review criteria that will be used in selection of successful projects subject to the CHPS.

Background

Hydrogen plays a critical role in a comprehensive energy portfolio for the United States, and the use of hydrogen resources promotes energy security and resilience as well as provides economic value and environmental benefits for diverse applications across multiple sectors in the economy.[1] The DOE is committed to creating and strengthening technologically and economically feasible production, processing, delivery, storage, and use of clean hydrogen fromdiverse fuel sources.

The BIL amended the Energy Policy Act of 2005 (EPAct 2005) to accelerate research, development, demonstration, and deployment of hydrogen from clean energy sources.[1] Section 40315 of the BIL states that "not later than 180 days after November 15, 2021, the Secretary, in consultation with the Administrator of the Environmental Protection Agency and after taking into account input from industry and other stakeholders, as determined by the Secretary, shall develop an initial standard for the carbon intensity of clean hydrogen production that shall applyto activities carried out under this subchapter."[2] Further, the statute directs that the Secretary shall determine no later than 5 years after the initial standard is published, if the standard shouldbe adjusted below the existing threshold and carry out the adjustment if deemed appropriate.

The statute requires that "the standard developed shall—"

- "support clean hydrogen production from each source described in section 16154(e)(2) ofthis title" (e.g., including but not limited to fossil fuels with carbon capture, utilization, and sequestration (CCUS); hydrogen-carrier fuels (including ethanol and methanol); renewable energy resources, including biomass; nuclear energy);
- "define the term "clean hydrogen" as provided in section 16166(b)(1)(B) to mean

[1] BIL Section 40311 (Findings; purpose.)
[2] 42 U.S.C. 16166(a).

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;and"

- "take into consideration technological and economic feasibility."[3]

Thus, the statute requires DOE to set a CHPS accounting for Congress's definition of "clean hydrogen" noted above, while also ensuring support for hydrogen production from diverse low-carbon energy sources, and consideration of technological and economic feasibility.[4] Accordingly, under the statute, the definition of clean hydrogen is a component of the CHPS but is not the sole component of the CHPS.

In this draft guidance, DOE seeks stakeholder comment on its proposal to implement the provisions of Section 40315 by adopting a CHPS that: (1) incorporates the definition of "clean hydrogen" provided in statute, and (2) supports diverse feedstocks and allows for consideration of technological and economic feasibility of achieving overall emissions reductions by establishing a lifecycle greenhouse gas emissions target for clean hydrogen production. The lifecycle target proposed in this draft also aligns with Section 13204 of the 2022 Inflation Reduction Act (IRA), which creates a new 10-year production tax credit (the 45V Credit) for "qualified clean hydrogen" defined with reference to the lifecycle greenhouse gas emissions rate of hydrogen production. [5] To qualify for a credit in the IRA, hydrogen must be 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."[6]

The CHPS is not a regulatory standard. Rather, it serves only to guide the DOE's hydrogen programs in EPAct 2005, as amended.[7] These include the Regional Clean Hydrogen Hubs Program and the Clean Hydrogen Research and Development Program. As set forth below, the BIL provisions governing Regional Clean Hydrogen Hubs (Hubs) provide that DOE can select projects that do *not* meet the CHPS so long as DOE selects projects that "demonstrably aid the achievement" of the CHPS by mitigating emissions as much as possible across the supply chain (e.g., through aggressive carbon capture onsite, measures to mitigate fugitive methane emissions, or use of clean electricity).[4] Additionally, the Clean Hydrogen Research and Development Program directs DOE to establish "a series of technology cost goals oriented toward achieving the CHPS."[5] Thus, these programs are expressly designed to reduce the carbon intensity of hydrogen production from diverse feedstocks over time. Accordingly, projects selected under those programs may not necessarily be required to meet the CHPS so long as they demonstrably aid the achievement of the CHPS.

While DOE-funded activities may not necessarily require achievement of the target set forth in the CHPS or achievement of an emissions intensity of 2 $kgCO_2e/kgH_2$ at the site of production (the definition of "clean hydrogen"), DOE may expect stakeholders to reduce emissions across

[3] 42 U.S.C. 16166(b).

[4] *Id.*

[5] Inflation Reduction Act of 2020, Sec. 13204, https://www.congress.gov/bill/117th-congress/house-bill/5376/text [6] The monetary value of tax credits available through 45V provision depends on the lifecycle emissions of a deployment. The provision has four tiers of credits, with each tier corresponding to a range of lifecycle GHG emissions, and lower emitting tiers corresponding to higher value credits.

[7] 42 U.S.C. 16166(a).

the supply chain as aggressively as technologically and economically feasible, and preference may be given to funding applicants on the basis of their emissions alongside other selection criteria. Previous DOE analyses of the emissions of hydrogen production from various feedstock have identified examples of parameters that could be optimized in real-world deployments to achieve these targets.[8,9] For example, DOE may give preference to projects that mitigate upstream fugitive emissions, use a cleaner electricity generation mix, employ high rates of carbon capture and sequestration, or blend fossil fuels with renewable natural gas or low-carbon biomass. When applying to DOE solicitations, applicants should review requirements and merit review criteria within those solicitations for corresponding guidance on DOE's expectations of successful proposals.

DOE's Proposed Clean Hydrogen Production Standard

Considering statutory factors within the BIL, DOE proposes that the CHPS establish an initial target for lifecycle greenhouse gas emissions of 4.0 $kgCO_2e/kgH_2$. This is consistent with the IRA's definition of "qualified clean hydrogen." This target is also likely achievable by facilities that achieve the BIL's definition of "clean hydrogen" as $\leq$2 $kgCO_2e/kgH_2$ at the site of production, and potentially have some additional emissions from upstream and/or downstream processes. As stated above, the establishment of a lifecycle target aligns with statutory requirements to consider not only emissions at the site of production but also technological and economic feasibility to support clean hydrogen production from diverse energy sources. This initial target of 4.0 $kgCO_2e/kgH_2$ is being proposed to encourage low-carbon hydrogen production from diverse feedstocks and using state-of-the-art technologies that are expected to bedeployable at scale today.

Fossil fuel systems that employ high rates of carbon capture or other thermal conversion processes such as pyrolysis, electrolysis systems that primarily use clean energy (e.g., renewables, nuclear), and certain biomass-based systems (e.g., gasification, reforming of renewable natural gas) are all generally expected to be capable of achieving 4.0 $kgCO_2e/kgH_2$ on a lifecycle basis using technologies that are commercially deployable today. For example, a steam methane reformer with ~95% carbon capture and sequestration (CCS) could achieve ~4.0 $kgCO_2e/kgH_2$ lifecycle emissions by using electricity that represents the average U.S. grid mix and ensuring that upstream methane emissions do not exceed 1%. Electrolysis systems that source about 15% of their electricity from the grid and the remainder from clean energy sources could also achieve ~4.0 kgCO2e/kgH2 lifecycle emissions. Both of these systems, and other pathways for hydrogen production (e.g., biomass gasification or reforming of renewable natural gas) could also achieve emissions lower than 4.0 $kgCO_2e/kgH_2$ through optimized design choices, such as the use of greater shares of clean electricity and low-carbon forms of biomass.[10]Over the coming decade, hydrogen production technologies that achieve the lifecycle target are also expected to become economically competitive through a combination of research,

[8] Lewis, E., et. al. Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies. DOE/NETL-2022/3241. Pittsburgh, PA. National Energy Technology Laboratory. https://www.netl.doe.gov/energy-analysis/details?id=ed4825aa-8f04-4df7-abef-60e564f636c9

[9] Elgowainy, A. "GREET Model for Hydrogen Life Cycle GHG Emissions". 2022 June 15. Argonne National Laboratory. https://www.energy.gov/sites/default/files/2022-06/hfto-june-h2iqhour-2022-argonne.pdf

[10] Emissions analysis conducted using GREET model cited in Footnote 9.

development, demonstration, and deployment to ultimately achieve economies of scale and private sector market lift-off.

Moreover, the 4.0 $kgCO_2e/kgH_2$ lifecycle target aligns with the new clean hydrogen policy drivers established in the IRA 45V Credit provisions described above. The proposed CHPS established under the BIL uses the same lifecycle analysis system boundary as the IRA and targets the emissions rate where the operators can begin to qualify for credits, thus creating alignment between the two statutory provisions.

System Boundary for Lifecycle Target

As shown in Figure 1 below, the emission sources that would be accounted for in the lifecycle target proposed in this draft guidance include upstream processes (e.g., electricity generation, fugitive emissions), as well as downstream processes associated with ensuring that CO_2 produced is safely and durably sequestered. Stakeholders have flexibility regarding how the lifecycle target could be achieved. For example, systems that do not release GHGs at the site of production or that achieve aggressive rates of carbon capture would have more flexibility for thedesign of upstream and downstream steps, while systems that use electricity with a lower carbonintensity or mitigate fugitive emissions would have more flexibility at the site of production. Thelifecycle system boundary accounts for these tradeoffs by including all key emissions sources associated with feedstock extraction or production, generation of electricity, feedstock delivery, hydrogen production, potential releases during CO_2 transport, and carbon capture and sequestration of GHGs generated by the production process. Examples of key emission sources within these steps are depicted in Figure 1 below.

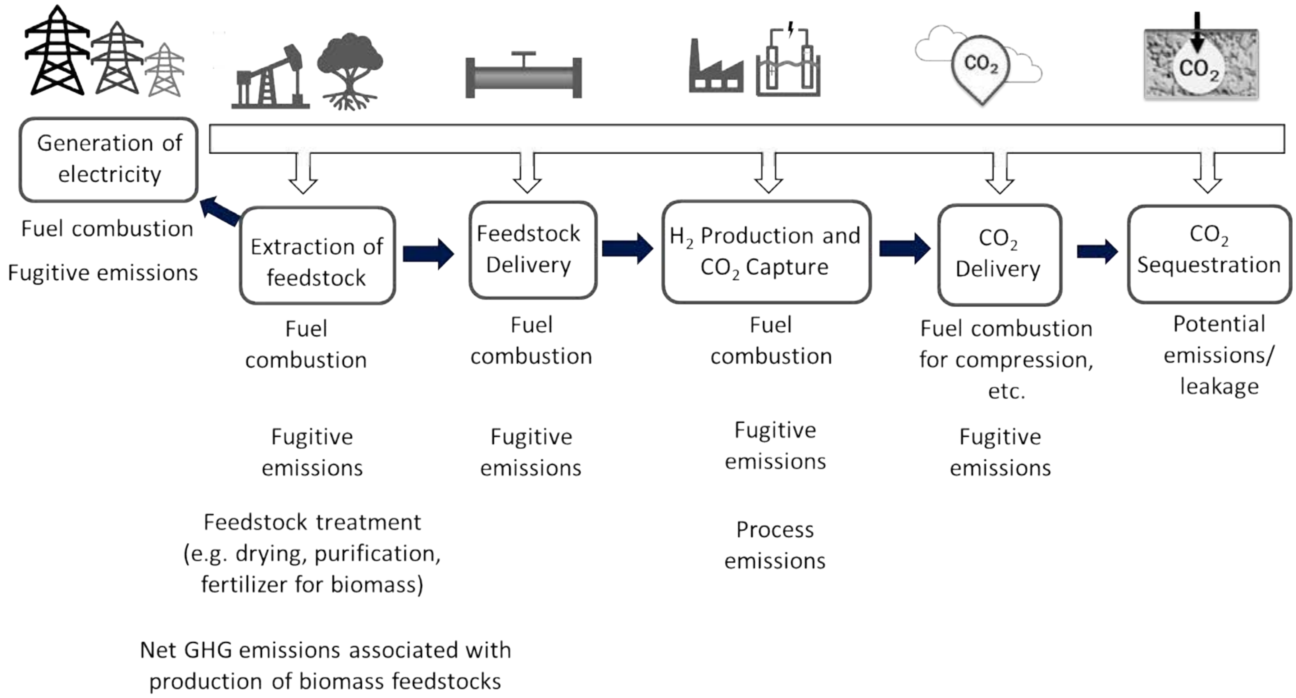

Figure 1: A lifecycle system boundary enables consistent and comprehensive evaluation of diverse hydrogen production systems. Examples of key emission sources within each step typically considered in the boundary are shown above.[11]

Emissions analysis using a lifecycle system boundary has been demonstrated by DOE and its National Laboratories in previous work,[12] is aligned with the 45V provision in IRA and is aligned with international best practices. Use of this system boundary will enable the nascent domestic industry to better integrate with global hydrogen markets. More than 20 countries havebeen coordinating since 2019 to harmonize emissions analysis methodologies and boundary conditions for hydrogen pathways through the International Partnership for Hydrogen in the Economy's (IPHE's) Hydrogen Production Analysis Task Force (H2PA TF), which is co-led bythe U.S.[13] The H2PA TF's initial work product focused on developing mutually agreed upon emissions analysis methods for hydrogen production and was published in a draft working paper recommending using a comprehensive system boundary including emissions upstream and

[11] In the CHPS, the lifecycle target corresponds to a system boundary that terminates at the point at which hydrogenis delivered for end use. This system boundary includes CCS even if sequestration is not at the site of production but does not include other post-hydrogen production steps such as potential liquefaction, compression, dispensing into vehicles, etc., consistent with the intent of a hydrogen production standard. To enable consistent comparisons across different hydrogen production technologies, the target corresponds to a functional unit of 1 kilogram of hydrogen at 99% purity and 3 megapascals (MPa) pressure. If a hydrogen production system achieves a higher pressure than this threshold, lifecycle analysis using GREET will adjust its emissions intensity accordingly. This adjustment is currently done by estimating the emissions that would have been generated by compression from 3 MPa to the pressure actually achieved and deducting these emissions from those generated by hydrogen production(effectively crediting the hydrogen production system for achieving a higher pressure that is likely to offset further compression requirements downstream).

[12] Elgowainy, A., "GREET Model for Life Cycle Analysis of Greenhouse Gas Emissions". Argonne NationalLaboratory. 2021 October 28. https://www.energy.gov/sites/default/files/2021-11/h2iq-hour-10282021.pdf

[13] For more information, please see https://www.iphe.net

downstream of the point of production.[14] As another example, a European project called CertifHy,[15] with roughly 100 industry partners determined that the most appropriate boundary conditions for hydrogen emissions analysis should include both upstream and downstream emissions. CertifHy has developed hydrogen certification schemes that cover both well to gate (WtG) and well to wheel system boundaries.

Notably, as set forth above, this approach to the CHPS will not categorically exclude projects from eligibility for DOE funding programs related to the BIL or EPAct 2005 if their emissions exceed the emissions threshold for "clean hydrogen" or the lifecycle target set by the CHPS. The BIL provisions governing Regional Clean Hydrogen Hubs make clear that DOE can select projects that do not meet the CHPS so long as the selected projects "demonstrably aid the achievement" of the CHPS.[16] Likewise, the Clean Hydrogen Research and Development Program directs DOE to establish "a series of technology cost goals oriented toward achieving the CHPS."[17] These goals may guide RDD&D activities to enable large-scale clean hydrogen deployments using diverse feedstock to achieve the targets in the CHPS in the long term.

Additionally, as noted above, the proposed target of 4.0 $kgCO_2e/kgH_2$ in the current draft guidance may be subject to revision based on stakeholder feedback. Based on this feedback, DOE intends to finalize guidance establishing the CHPS. The CHPS may then be subject to revision within 5 years, as required by the BIL. Data from demonstration and deployment projects, including the Hubs, will inform those future revisions. It is also important to note that DOE encourages stakeholders to reduce lifecycle emissions to the greatest extent possible, and that other policies and market forces may incentivize deployments that are cleaner than the targets established in the CHPS.[18]

DOE seeks feedback on this proposal by October 20, 2022. DOE will use feedback on thisproposal to finalize its initial guidance.

Stakeholder Feedback

The statute requires DOE to consider input from industry and other stakeholders before establishing the CHPS. As such, DOE is seeking feedback on the proposed CHPS and information on data that will inform the value of the CHPS. Please provide comments to Cleanh2standard@ee.doe.gov by October 20, 2022.

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[14] IPHE 2021, Methodology for Determining the Greenhouse Gas Emissions Associated With the Production of Hydrogen, A Working Paper Prepared by the IPHE Hydrogen Production Analysis Task Force, Available online:https://www.iphe.net/iphe-working-paper-methodology-doc-oct-2021

[15] https://www.certifhy.eu/

[16] 42 U.S.C. 16161a(b)(1).

[17] 42 U.S.C. 16154(e)(1).

[18] For example, deployment of technologies that can achieve even lower lifecycle emissions may be incentivized by policies being established in other countries. The European Taxonomy classifies clean hydrogen as that which achieves lifecycle emissions of <3.0 $kgCO_2e/kgH_2$ and the European Renewable Energy Directive sets a lifecycle target of approximately 3.4 $kgCO_2e/kgH_2$. As another example, the United Kingdom set a standard of 2.4 $kgCO_2e/kgH_2$. To support achievement of such targets, technologies that can achieve less than 4.0 $kgCO_2e/kgH_2$ mayadvance over the coming years, which may further enable their deployment domestically.

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.

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 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?

Currently, GREET uses a single national average CI factor for the NG Scope 3 emissions (upstream emissions in NG supply chain). This factor may not accurately reflect large regional differences in Scope 3 for NG from different sources. The CI factors for power in GREET are usually old (back dated by 3 – 5 yrs) and do not reflect increase in renewable power production. On the flip side, it is not clear if GREET uses residual mix factors (after accounting for PPAs for different generation sources). If residual mix factors are not used, then the possibility exists for double counting benefits of renewable power.

One common issue for the above is expected improvements in CI factors of all energy sources over the project's lifetime. If the grid gets greener and NG supply gets cleaner, the lifetime GHG emissions of any project at the beginning of a 15-year project may be significantly overestimated.

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.

CO_2 venting from gas processing plants should be listed. This is not associated with leaks (i.e., fugitive), but CO_2 separated from CO_2-rich NG to meet pipeline specs.

d) Mitigating emissions downstream of the site of hydrogen production will require close monitoring of potential CO_2 leakage. What are best practices and technological gaps associated with long-term monitoring of CO_2 emissions from pipelines and storage facilities? What are the economic impacts of closer monitoring?

Every pipeline operator has a mass-balance based system in place to track product flows and to do reconciliations for billing process; this already existing work process can be leveraged for leak detection on the pipelines with minimal cost impact.

e) 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 indirectimpact?

Using some published values of H2's GHG potential, this impact is much smaller than most people think. Key is the GHG potential value that should be used. In our view, a reputable organization such as IPCC (Intergovernmental Panel on Climate Change) should establish a consensus value that everyone can use. Major sources of hydrogen leaks are likely from LH2 production and distribution and to a smaller extent from H2 compression equipment. Pressurized H2 transport can be designed to be essentially leak-free.

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

It will be complicated to come up with a generic approach for CO_2 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?

The framework is reasonable but more explicit guidance should be provided on what Scope 3 emissions should be included and excluded.

In addition, the definition of LCA boundary should be given more consideration – page 19 mentions "from raw material to end of life treatment". it is particularly challenging to understand downstream Scope 3 emissions due to the lack of visibility into these processes and versatile applications of hydrogen in some cases. A "well to product/gate" methodology will be preferred since producer can control the scope 1, 2 and upstream scope 3 emissions to some extent.

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 CO_2 emissions, especially given scenarios wherein biogenic waste stream-derived materials and/or

[19] Paulot, F., Paynter, D., Naik, V., Malyshev, S., Menzel, R., and Horowitz, L. W.: Global modeling of hydrogen using GFDL-AM4.1: Sensitivity of soil removal and radiative forcing, Int. J. Hydrogen Energy., 46, 13446–13460, https://doi.org/10.1016/j.ijhydene.2021.01.088, 2021.

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?

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?

The two most relevant approaches for H2 production are system expansion and energy allocation. Please The IPHE methodology document specifies the following order of allocation on Page 34,

- Allocation based on Energy content;
- Allocation based on System expansion;
- Allocation based on Economic value.

But within the document the recommended use of allocation methodologies is not consistent in various Hydrogen pathways described in the document. For example, on Page 47, for SMR-based H2 plant producing steam and/or power for export, it is recommended to use energy allocation. Whereas on Page 69, for H2 from coal gasification pathway it is suggested that system expansion should be used to allocate emissions to steam and power.

We request you to provide consistent guidance on which of these allocation methodologies are to be used across the pathways.

We also recommend that system expansion should be allowed to be used as preferred allocation method for utility by-products (steam and power) when by-product's utility and understanding of the market for the by-products is clear. This is also an allowed allocation approach in models such as GREET and CARB-GREET.

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)?

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?

LCA calculation using GREET or H2PATF including scope 1, 2, 3 can be used for the assessment. Need feedstock, electricity, steam, H2 product, CO_2 capture data, etc for the calculation.

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?

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?

RECs with regional considerations and reasonable time of generation constraints should be allowed

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

4) Additional Information

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

Natural gas upstream emissions: Specify if supplier specific data is available for upstream carbon intensity of natural gas, can those values be used to calculate hydrogen's CI instead of default numbers in GREET model? If yes, specify what documentation will be needed to "authenticate" the upstream emissions factor of such natural gas.

Certified Natural Gas: DOE should allow use of Certified natural gas or responsible sourced gas (RSG) to reduce the Hydrogen's life cycle carbon footprint. Certified natural gas/RSG is gas that is verified to have lower upstream methane emissions. Various certification standards currently exist such MiQ, Project Canary that certify the lower upstream emissions of natural gas.

DOE should provide guidance on what kind of documentation will be required for validation of such natural gas' use in the project. Also specify if these standards (MiQ, Project Canary) will be allowed to be used as upstream emissions authentication documents.

H_2 Liquefaction: For end use in liquid form, it is not clear if emissions from power consumption for H_2 liquefaction needs to be included in the CI calculation or not. Please provide clear guidance in the document.