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Stakeholder Feedback on DOE Proposed Clean Hydrogen Production Standard

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Executive Summary

DOE's proposed Clean Hydrogen Production Standard (CHPS) represents a crucial opportunity to signal early ambition, demonstrate hydrogen's potential as a decarbonization solution, and set 'best in class' industry standards. The CHPS should also represent a first step toward developing a broader clean hydrogen lifecycle standard that applies to all hydrogen projects – not just DOE investments. As the hydrogen economy evolves, it will be increasingly important to align markets and ensure that hydrogen is truly meeting its promise as a climate and environmental solution. While it may be too early to set such an industry-wide standard today, the DOE CHPS offers an opportunity to test feasibility and establish the enabling processes around data collection, reporting and verification.

DOE's proposed standard of 4.0 kg CO_2e/kg H2, on a well-to-gate basis, makes strides toward maximizing hydrogen's climate objectives, including considering other lifecycle stages beyond the point of production. However, EDF believes the standard can go even further:

- The current standard of 4.0 kgCO_2e/kgH2 is not sufficiently rigorous. Industry should be driving towards attainable goals like a total upstream methane rate of 0.4% or less, CCUS capture efficiency at or above 90%, and a leakage rate from long-term geologic storage of CO2 of no more than 1% over 1,000 years[1] – which together yields a significantly lower emissions intensity.
- DOE should more clearly explain how it will adhere to the CHPS and ensure developed projects "demonstrably aid achievement" of climate goals.
- DOE should move toward more comprehensive lifecycle assessments (LCA), including more stages of the lifecycle, all direct and indirect GHGs, and multiple time horizons (100-year and 20-year). This requires key updates to the GREET model.
- DOE should note the importance of accounting for hydrogen emissions and an intent to empirically account for hydrogen emissions in LCAs once it becomes technically feasible to do so. In the meantime, DOE should consider adopting interim hydrogen emissions rate estimates.
- DOE should make LCA estimates publicly available, both to enable early-stage industry learning and to facilitate future updates to the CHPS, as required by legislation.
- DOE should work with the EPA to establish a monitoring and measurement program coupled with on-site verification of reported lifecycle emissions. The GHGRP can serve as a basis, supplemented with additional reporting requirements and methodological updates.
- Fossil fuel-based hydrogen hub developers should be required to identify the basin from which their gas is sourced and provide verified, company-specific emissions data.
- DOE should work to establish a rigorous emissions accounting framework for grid-connected electrolyzers that reduces system-wide GHG emissions through additionality, regionality, and granular temporal matching.

Each of these points is elaborated upon in the following set of comments.

[1] EDF would also recommend a total hydrogen emissions target of no more than 1%, once technically feasible

Introduction

Environmental Defense Fund (EDF) appreciates the opportunity to provide comments on DOE's proposed Clean Hydrogen Production Standard (CHPS). Clean hydrogen has emerged as key strategy in the transition to clean energy. It offers the potential to solve pressing energy challenges for 'hard-to-abate' sectors such as steel and cement production and parts of global transportation, which have fewer readily available alternatives to fossil fuels and feedstocks. However, hydrogen also presents climate, environmental, and social risks, and its development must be undertaken carefully, responsibly, and equitably.

This includes designing a clean hydrogen production standard that maximizes hydrogen's climate benefits. Because this particular standard will guide DOE's investment decisions on hydrogen hubs and R&D, it represents a crucial opportunity to signal early ambition, demonstrate hydrogen's potential as a decarbonization solution, and set 'best in class' industry standards. It will also likely serve as a reference point for states considering their own clean hydrogen definitions and eligibility, giving it even greater industry weight.

While the CHPS currently applies only to DOE investments, it should represent a first step toward developing a broader clean hydrogen lifecycle standard that applies to all hydrogen projects. A robust and comprehensive industry standard will be crucial to preserve the environmental integrity of the clean hydrogen industry, to shape decisions on private investments and policy support (at multiple levels of government), and to facilitate international and domestic markets. While it may be too early to set such an industry-wide standard today, the DOE CHPS represents a crucial opportunity to test feasibility and establish the enabling processes around data collection, reporting and verification.

Lifecycle Scope

DOE's proposed standard of 4.0 kg CO_2e/kg H2, on a well-to-gate basis,[2] makes strides toward maximizing hydrogen's climate objectives, including considering other lifecycle stages beyond the point of production.

The IIJA directs DOE to account for multiple considerations when developing CHPS, and we support DOE in doing so.[3] The standard developed under section 16166(a) must account for factors beyond the point-of-production carbon intensity specified in the statute.[4] Given the degree to which greenhouse

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[2] Well-to-gate emissions refer to those associated with feedstock extraction (e.g., natural gas drilling), generation of electricity (used in numerous steps associated with hydrogen production), feedstock delivery (e.g., natural gas compression, natural gas leakage), hydrogen production (e.g., reforming, electrolysis, gasification, pyrolysis), and delivery and sequestration of CO2 (e.g., fuel combustion for compression, leakage).

[3] Section 16166(a) requires DOE to "develop an initial standard for the carbon intensity of clean hydrogen production that shall apply to activities carried out under [42 U.S.C. § 16151 et seq.]." 42 U.S.C. § 16166(a)-(b)

Section 16166(b)(1) then sets out three general requirements for the standard: a) "support clean hydrogen production" from various sources; b) employ a point-of-production carbon intensity of 2kg/CO2e or less, and c) "take into consideration technological and economic feasibility." *Id*. § 16166(b)(1)(A)-(C)

These three general requirements are components of the standard under section 16166(a), which must also be developed in consultation with the Environmental Protection Agency and after considering stakeholder input.

[4] The definition of "clean hydrogen" in section 16152 also supports this: "The terms 'clean hydrogen' and 'hydrogen' mean hydrogen produced in compliance with the greenhouse gas emissions standard established under section 16166(a) of this title, including production from any fuel source." While DOE must consider multiple factors when setting the CHPS, the statute is clear that the point-of-production carbon intensity cannot exceed 2kg/CO2e. *Id.* § 16166.

emissions arising upstream (and downstream) of the point of production can dictate the final emissions profile of hydrogen production pathways, it is crucial to account for these emissions.

As it becomes technically and methodologically feasible, a full industry standard must include an even broader lifecycle scope – including hydrogen emissions, in addition to CO2 and methane, and covering additional downstream phases all the way to end use. DOE should utilize this opportunity to begin collecting comprehensive emissions data and inform the standard's evolution.

Moreover, lifecycle assessments should consider climate impacts on both long-term and short-term time horizons. The GWP100 metric significantly understates the warming impacts of short-lived GHGs – like methane and hydrogen – in the near term.[5]

(EDF has provided additional comments regarding lifecycle accounting later in response to 1b, 1c, and 2a.)

Target Level

Given that DOE's standard applies to investment decisions on R&D and demonstration projects, it should be designed to set 'best in class' standards and demonstrate the feasibility of decarbonization pathways. By this measure, a GHG-intensity of 4.0 kgCO2e/kgH2 ending at the point of production is not sufficiently rigorous. EDF believes that industry should be driving towards attainable goals like a total upstream methane rate of 0.4% or less, CCUS capture efficiency at or above 90%, and a leakage rate from long-term geologic storage of CO2 of no more than 1% over 1,000 years – all of which have been deemed technically feasible.[6]

Yet under DOE's proposed threshold, CCUS capture efficiency could be as low as 64% or methane leakage rates as high as 3.4%.[7] Such leniency leaves significant climate benefits unrealized, which threatens the cost/benefit analysis of hydrogen as a decarbonization option. This is particularly true considering that the standard is currently based on solely a 100-year time horizon and neglects near-term warming effects.

In its draft, DOE acknowledges that other countries have deemed it technically feasible to set stronger targets – including the European Taxonomy clean hydrogen classification of <3.0 kgCO2e/kgH2, the

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[5] Sun, Tianyi, *et al*., 2021. Path to net zero is critical to climate outcome. *Scientific Reports* 11, https://www.nature.com/articles/s41598-021-01639-y; and Ocko, Ilissa *et al.* Unmask temporal trade-offs in climate policy debates. *Science* 356, 492–493 (2017), https://www.science.org/doi/10.1126/science.aaj2350.

[6] EDF would also recommend a total hydrogen emissions target of no more than 1%, once technically feasible.

0.4% is based on the production segment leakage target of 0.20% set by the Oil and Gas Climate Initiative and the combined leak for gathering, processing or transmission reported by OneFuture. (OneFuture, 2021. *2021 Methane Emissions Intensity Overview*, https://onefuture.us/2021-methane-emissions-intensity-report/); A demonstrated CO2 leakage rate of no more than 1% over 1,000 years was indicated likely by the IPCC CCS report in 2005. (IPCC, 2005. "Carbon Dioxide Capture and Storage." Cambridge Univ. Press, UK, https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf)

[7] Our calculations suggest that a 4.0 kgCO2e/kgH2 standard could be met with a 0.4% methane leak rate and CCUS capture rate of 64%, or a 3.5% methane leak rate and CCUS capture rate of 90%. (Methane leak rates of 3.5% have been observed from production across the Permian Basin. https://www.edf.org/media/new-data-permian-oil-gas-producers-releasing-methane-three-times-national-rate)

Both calculations assume an unmitigated SMR baseline of 10 kgCO2e/kgH2 and a GWP100 factor of 29.8 for methane.

European Renewable Energy Directive target of 3.4 kgCO2e/kgH2, and the UK low-carbon hydrogen standard of 2.4 kg CO2e/kgH2. Not only is it in DOE's interest to position itself as a world leader in hydrogen decarbonization by utilizing more stringent criteria, but alignment of GHG intensities is also a key enabler of international trade. A substantially more carbon-intensive standard creates risks for the US export market.

EDF believes DOE has latitude to adjust this level downward. The CHPS was intended to direct DOE decisions on hydrogen hubs and R&D, rather than to inform eligibility for the hydrogen production tax credit (45V). These two policy instruments are designed to serve different functions and meet different innovation challenges (demonstrating feasibility, in the case of CHPS, and scaling up, in the case of 45V). Thus they do not necessarily need to be aligned. Moreover, by outlining different tiers, the PTC itself implies that lower GHG intensities (such as 2.5, 1.5, or 0.45 kgCO2e/kgH2) hold greater value.

Adherence to CHPS

DOE proposes to treat the standard as non-binding – meaning, DOE could invest in projects that fall above 4.0 kg CO2e/kgH2 so long as they "demonstrably aid the achievement" of the CHPS. The quoted language is unclear, which could reduce the incentive for ambitious decarbonization and undermine DOE's ability to ensure projects meet their projected lifecycle emissions commitments during and after project development.[8] We therefore urge DOE to more clearly explain how it will adhere to the CHPS and ensure developed projects meet or exceed the CHPS and their projected and claimed climate goals.

Further, DOE must ensure that the IIJA directive of 2.0 kgCO2e/kgH2 (or less) <u>at the point of production</u> is achieved in every instance as Congress intended. This preserves an important assurance mechanism that may be needed in the future – e.g., in the event that a project grossly fails to deliver on its climate promises. This will also ensure the clean hydrogen standard remains minimally protective over time.

The CHPS represents an opportunity for DOE to catalyze ambitious emissions abatement, catch up with international peers paving the way on hydrogen sustainability, and hold companies accountable for their climate impacts. To take advantage of this opportunity, DOE must go further in strengthening this standard's rigor and committing to its achievement – while laying the groundwork for an even broader industry lifecycle standard. EDF appreciates the opportunity to advise and has provided several more specific comments in response to DOE's questions below.

1. **Data and Values for Carbon Intensity**

    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?**

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[8] We also note that both the definition of "clean hydrogen" in 42 U.S.C. § 16152 and the language in the CHPS provisions of 42 U.S.C. § 16166 appear to envision a central role for the CHPS in all activities carried out under the subchapter.

GREET's default estimates of carbon intensity for parameters that are not likely to vary widely by deployments in the same region of the country are assumed to be accurate. GREET relies on a variety of data sources, which include open literature and results from other researchers, simulations with models, stakeholder inputs, and baseline technologies and energy systems, such as EIA AEO projections and EPA's eGrid for electric systems.[9]

However, data accuracy aside, it is not clear to EDF based on our analysis of GREET that the model is currently capable of meeting the full scope of need for a cradle to grave assessment of clean hydrogen, given that it does not incorporate hydrogen emissions and is primarily focused on transportation as an end use. As DOE more clearly establishes the parameters of the clean hydrogen standard and the necessary reporting processes, it should ensure that the model is properly updated in order to comprehensively account for and assess emissions in a manner that fits the current standard and its future evolution.

To have a thorough accounting for clean hydrogen production emissions as the hydrogen economy develops, GREET will need to begin incorporating hydrogen as a greenhouse gas and using shorter timeframes for global warming potentials of short-lived pollutants like hydrogen and methane. Within GREET, the default global warming potentials of these greenhouse gases are presented as 100-year values, which underestimates the damage done by short-lived greenhouse gases. For example, methane's 100-year global warming potential is 27-30 times that of carbon dioxide while it's 20-year global warming potential is 80-83.[10] GREET should include an advisory about using GWP20 values to estimate the climate impacts of methane. Moreover, hydrogen, which is a powerful indirect greenhouse gas that triggers warming effects in the atmosphere for a decade after it is emitted, should also be included as an emissions source within GREET. (See responses to 1c and 2a for more details.)

For GREET to fully be able to conduct a cradle to grave analysis for clean hydrogen, it must also be updated to include a full suite of hydrogen end-uses and consider the temporal dynamics associated with those emissions and those of methane.[11] Without such inclusions the analysis provides a spurious understanding of the climate comparative implications of producing and using hydrogen. GREET is primarily a transportation focused model. It can comprehensively evaluate energy and emissions impacts of advanced and new fuels and the fuel cycle from well to wheel. However, hydrogen will have other end uses beyond transportation, and the current model is not well-suited to conduct full lifecycle analysis for non-transportation applications (apart from steel production). GREET should be updated to ensure its accuracy in non-transportation applications and any temporal implications.

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.**

Hydrogen as an Indirect GHG

DOE's proposed standard applies to greenhouse gases beyond just CO_2, (specifically mentioning methane) and it spans multiple life cycle stages and types of emissions (due to fuel combustion, fugitive,

[9] Wang, Michael (2015). GREET Life-Cycle Analysis Model and Key LCA Issues for Vehicle/Fuel Transportation. https://www.concawe.eu/wp-content/uploads/2017/01/Michael-Wang_GREET-Life-Cycle-Analysis-Model.pdf

[10] IPCC Sixth Assessment Report, Chapter 7 - https://www.ipcc.ch/report/ar6/wg1/chapter/chapter-7/

[11] Incorporating 20-year time horizons into LCAs can easily be done, utilizing GWP factors 80 (83 if fossil origin) for methane, and 33 for hydrogen.

process, etc.). However, it does not explicitly state whether hydrogen emissions – due to leaking, venting, or purging – would be included in the LCA calculation.

Hydrogen is a short-lived, indirect GHG that causes warming by increasing the concentration of other GHGs in the atmosphere. It is also a small and slippery molecule that can easily escape from all parts of the value chain. Recent studies found hydrogen's warming power is over 30 times larger than CO_2 pound for pound over the 20 years after it is emitted, and about 10 times larger over 100 years – values that are 2-6 times higher than previously thought.[12] EDF research shows that if the hydrogen emission rate is high across the value chain, it can severely undermine the intended benefits of clean hydrogen.[13]

Calculations suggest that this emissions source may have a material effect on GHG intensity when both direct and indirect warming are considered. For illustration, we estimate that for a blue hydrogen facility with a 90% capture rate and 2.3% methane leakage rate, limiting hydrogen emissions to 1% would yield a GHG intensity of 3.2 $kgCO_2e/kgH_2$. However, under a high hydrogen emissions scenario of 10%, GHG intensity would rise to 4.5 $kgCO_2e/kgH_2$ – falling below the proposed standard.[14]

Currently, estimates of hydrogen leakage rates range considerably, due to a lack of empirical data on leakage from specific infrastructure such as electrolyzers, pipelines, and storage. However, development of appropriate sensor technologies is currently underway which would enable such measurement. (See response to 1e for more details.)

Thus, EDF believes that **hydrogen emissions should be explicitly included within LCAs once emissions rates are able to be empirically assessed and/or reasonably estimated.** We applaud DOE's notice to companies in the hydrogen hubs Funding Opportunity Announcement (FOA) that they may be required to monitor and report hydrogen emissions as soon as technically feasible. In the meantime, DOE should consider adopting interim hydrogen emissions rate estimates for different production processes and life cycle phases that can be incorporated into project developers' LCAs. We have summarized below the range of hydrogen emission rate estimates for production and downstream activities and have provided relevant literature sources.

Production Emission Estimates

Hydrogen emissions associated with production include both unintended leakage and intentional purging/venting. For example, some hydrogen is currently vented as part of the waste gas from the purification/drying process of electrolysis. Overall, estimates of emissions associated with electrolytic hydrogen production currently range from 0.1% to 9.2% (with the upper estimate including intended venting as well as unintended leakage).[15] Emissions from operational venting/purging can be controlled by incorporating technology that recombines purged and vented hydrogen back into the electrolysis

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[12] Ocko, Ilissa and Hamburg, Steve (2022). "Climate consequences of hydrogen leakage." Atmospheric Chemistry and Physics. Vol. 22, Issue 14. https://acp.copernicus.org/articles/22/9349/2022/; and Warwick et al., (2022). "Atmospheric Implications of Increased Hydrogen Use". Department for Business, Energy & Industrial Strategy. https://www.gov.uk/government/publications/atmospheric-implications-of-increased-hydrogen-use

[13] Ocko, Ilissa and Hamburg, Steve (2022). "Climate consequences of hydrogen leakage." Atmospheric Chemistry and Physics. Vol. 22, Issue 14. https://acp.copernicus.org/articles/22/9349/2022/

[14] Assumes a SMR baseline of 10 kg CO2 / kg H2

[15] The low-end emission rate estimate is from Cooper et al., (2022). "Hydrogen emissions from the hydrogen value chain-emissions profile and impact to global warming". Science of the Total Environment. Vol. 830. https://linkinghub.elsevier.com/retrieve/pii/S004896972201717X

The upper-end emission rate estimate is from Frazer-Nash Consultancy (2022). "Fugitive Hydrogen Emissions in a Future Hydrogen Economy". https://www.gov.uk/government/publications/fugitive-hydrogen-emissions-in-a-future-hydrogen-economy process. We recommend DOE requires these best practices to eliminate hydrogen purging and venting, as discussed in more detail in 1e.

Blue hydrogen production is estimated to have less than 1.5% hydrogen emissions, since waste gas is likely to be flared or used for process heat.[16]

Downstream Emission Estimates

Beyond production, hydrogen has the potential to leak from various delivery segments of the value chain from processes including compression, liquefaction, storage, and transportation via pipelines or trucks. Hydrogen is a challenging molecule to contain because it has a low volumetric energy density relative to existing carriers like natural gas, so it is often stored at high pressure or liquified, which then has a higher potential to leak. Liquid hydrogen is particularly prone to boil-off loss. For example, a recent report suggests liquid hydrogen handling currently has a loss rate of 10-20%.[17] Overall, current estimates of leakage rates for the full hydrogen value chain, including production, processing, storage and delivery, range from 0.3% to 20%.[18]

However, even many of these estimates offer limited reliability. Studies on hydrogen leakage often rely on natural gas supply chain leakage as a proxy, and there is a high degree of uncertainty in existing methane emission estimates. Moreover, the patterns of hydrogen leakage can be different from that of methane, with fluid dynamics theory suggesting that hydrogen can leak 1.3 to 3 times faster than methane,[19], and experimental studies suggest different leak rates for different leak regimes.[20]

Please see response to 2a for comments regarding inclusion of downstream activities in LCAs.

The table below includes several key sources of emission estimates to date. Many of these differ in assumptions regarding supply chain stages.

Paper	Range of emission rate	Lifecycle stages included
Schultz et al., 2003	3% to 10% Up to 20% is possible, but highly unlikely due to safety and economic considerations	Full life cycle Also states that leak rates below 0.1% can be achieved in ***industrial*** applications

[16] Arrigoni, A. and Bravo Diaz, L. (2022). “Hydrogen emissions from a hydrogen economy and their potential global warming impact”. Publications Office of the European Union, Luxembourg. doi:10.2760/065589, JRC130362.

[17] Arrigoni, A. and Bravo Diaz, L. (2022). “Hydrogen emissions from a hydrogen economy and their potential global warming impact”. Publications Office of the European Union, Luxembourg. doi:10.2760/065589, JRC130362.

[18] The low-end estimated full value chain leakage is from van Ruijven et al., (2011). “Emission scenarios for a global hydrogen economy and the consequences for global air pollution”. Global Environment Change, Vol. 21, Issue 3. https://www.sciencedirect.com/science/article/pii/S0959378011000409 The upper end estimated leakage for the full value is from Schultz et al., (2003). “Air Pollution and Climate-Forcing Impacts of a Global Hydrogen Economy”. Science, Vol. 302. https://www.science.org/doi/10.1126/science.1089527

[19] Swain, M. R. and Swain M. N. (1992). “A Comparison of H2, CH4, ad C3H8 Fuel Leakage in Residential Settings”. International Association for Hydrogen Energy, Vol. 17, Issue 10. https://doi.org/10.1016/0360-3199(92)90025-R

[20] Mejia, A, et al. (2020). “Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure”. International Journal of Hydrogen Energy”. Vol. 55, Issue 15. 10.1016/j.ijhydene.2019.12.159

Penchev, M. et al. (2022). Hydrogen Blending Impacts Study Final Report. University of California, Riverside. Agreement Number: 19NS1662

Tromp et al., 2003	10% to 20% Losses during current commercial transport of H2 are substantially greater than 10%, suggesting an upper boundary of 20% should be expected	Production, storage, and transport
Warwick et al., 2004	1% to 12%	Production, transport, and storage.
Colella et al., 2005	1% to 3% for a gaseous-based hydrogen economy, noted liquid hydrogen could result in higher leak rate; considered 10% leak rate as an extreme case	Transportation sector only – well to wheel
Jacobson et al., 2005	1% to 10% leak rate Noted that gaseous-based hydrogen economy would have a hydrogen leakage rate between 1% to 3% Liquid-based hydrogen economy could result in a significant leakage rate of 10% of all hydrogen produced, although 10% may be an unlikely upper bound	Production, transport, and storage
Jacobson 2008	3% This is a leakage rate assumed for one specific hydrogen use case where the world's on-road vehicle fleet is converted wind-powered hydrogen fuel cell vehicles	Transport sector only – for wind-powered hydrogen fuel cell vehicles, from well-to-wheel
Wuebbles et al., 2010	2.5%, noted that confidence in current knowledge of leak rates is low and not aware of any real-world measurements	Only consider transportation sector, and assumes total world road transportation switches to H2 economy
Van Ruijven et al., 2011	0.3% to 10% depending on the configuration of the total hydrogen system	Full value chain
Bond et al., 2011	1% to 4%	Full value chain
Paulot et al., 2021	0.3% to 10%	Full value chain estimate based on existing literature
Cooper et al., 2022	0.3% to 20%, considered all ranges in existing literature	Production (compared emission estimates for blue, biomass, and green hydrogen), transmission and distribution, and storage.
Fan et al., 2022	2.9% to 5.6%	Full value chain
Frazer-Nash Consultancy, 2022	0.96% to 1.5%	Full value chain
Warwick et al., 2022	1-10%	Production, transportation, and storage

Arrigoni & Bravo Diaz 2022	0.8% to 2%	Full value chain

d. **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?**

CO_2 Pipelines: Recent hazardous events make clear that best practices and regulatory programs related to safely managing CO2 pipelines deserve serious reconsideration and improvement in advance of an increase in this transport option. CO_2 leakage is both an environmental and safety concern, and it will be vital to develop rules requiring (1) regular leak surveys using advanced technologies combined with fast repair protocols, as well as (2) planning and mitigation of risks related to land-movements and geohazards. The proper prioritization of these leakage risks and implications in DOE's Clean Hydrogen Production Standard would be valuable in encouraging swift and effective improvements. EDF recommends that DOE reference the following resources to better assess the current best practices and technological gaps associated with CO_2 pipelines:

1. Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S., prepared for the Pipeline Safety Trust (March 2022), *available at* https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf.
2. US Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *Failure Investigation Report – Denbury Gulf Coast Pipelines, LLC – Pipeline Rupture/Natural Force Damage* (May 2022), *available at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf.
3. *PHMSA Announces New Safety Measures to Protect Americans from Carbon Dioxide Pipeline Failures After Satartia, MS Leak*, PHMSA.DOT.GOV, May 26, 2022, https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures .

Geologic CO_2 Storage: As a foundational principle, the Intergovernmental Panel on Climate Change has made clear that well-selected, designed and managed geologic carbon storage sites will likely retain a vast majority (over 99%) of injected volumes for thousands of years or longer (IPCC 2005; IPCC 2022). However, the process of properly selecting, designing and managing these sites is not trivial and must be appropriately regulated and monitored to ensure and demonstrate secure outcomes. Proper demonstration of secure storage of carbon captured in association with the hydrogen production process should be a vital component of assessing the "clean" claims of that hydrogen – this underscores the importance of properly permitted carbon storage wells and associated monitoring, reporting, and verification (MRV) plans approved under Subsection RR of EPA's Greenhouse Gas Reporting Regulations. DOE should ensure, in addition to incorporating leakage into life cycle assessments, that clean hydrogen projects involving carbon storage operate consistently with established best practices and operate under approved MRV plans. It may be that some available best practices, such as DOE's own Best Practices Manuals for geologic storage should be updated in light of recent and future expanded activity and importance since 2017. EDF recommends the following guidance documents related to carbon dioxide leakage monitoring (EPA's General Technical Support Document is recommended for the provisions relating to Subpart RR):

4. IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 5: Carbon Dioxide Transport, Injection and Geological Storage (2006), https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_5_Ch5_CCS.pdf.
5. U.S. Department of Energy, Best Practices: Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects (2017), DOE/NETL-10`7/1847, https://www.netl.doe.gov/sites/default/files/2018-10/BPM-MVA-2012.pdf.
6. U.S. Environmental Protection Agency, General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU Greenhouse Gas Reporting Program (November 2010), https://www.epa.gov/sites/default/files/2015-07/documents/subpart-rr-uu_tsd.pdf (sections related to RR only are relevant to the question presented).

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 indirect impact?

Empirical data collection is critical to understanding site level hydrogen emissions at commercial facilities. EDF has learned, through decades of work on methane emissions measurement and quantification, that component level emission factors can lead to severe underestimation of real-world emissions.[21] Facility level data collection and emission quantification requires high frequency (seconds) and high sensitivity (low ppb level) sensing technologies and well demonstrated dispersion models. While emission factors can be a useful tool to estimate total supply chain emissions, they should be verified with empirical data.

Atmospheric measurement of hydrogen concentration can also be used to understand hydrogen emissions and the global hydrogen budget. Existing measurements by the Global Monitoring Lab at NOAA should be well managed and possibly expanded, to further our understanding of natural and anthropogenic hydrogen emissions and verify atmospheric modeling efforts.

While the requisite sensor technologies are being developed, the industry should make plans to implement (and budget) for hydrogen measurement, reporting and verification systems, as well as leakage and repairs.

In the meantime, the industry should explore several common-sense best practices that may reduce hydrogen leakage, including but not limited to:

- Minimizing boil-off and otherwise eliminating venting of hydrogen gas, applying oxidation for vented gas when possible
- Proper treatment of hydrogen losses during electrolysis, such as recombination of hydrogen with oxygen
- Stronger insulation of pipes and storage vessels, as well as proper materials (e.g., plastic lining)
- Minimizing transport and delivery / co-locating facilities

[21] Alvarez, Ramon, et al. (2018). "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." https://www.science.org/doi/10.1126/science.aar7204

- Minimizing points of pressurization and depressurization
- Regular facility inspections

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?**

Downstream Scope 3 Emissions

The IPHE framework of life cycle emissions takes an important step of including Scope 2 and partial Scope 3 emissions, reflecting the importance of considering the entire system impact of a fuel. However, EDF believes that LCAs should be expanded even further to include additional downstream Scope 3 emissions that would have a material effect on climate outcomes – including those associated with liquefaction, compression, storage, transport, delivery, and distribution. Indeed, the HPTF Working Paper notes the importance of considering downstream emissions associated with hydrogen infrastructure and transportation and promises to revisit this topic in future reports.

IPHE suggests that one criterion by which system boundaries should be judged is the materiality of the emissions and whether they are projected to decline in the future (i.e., this is the rationale for not including emissions from construction of capital goods or business travel).[22] Under this same criterion, downstream hydrogen emissions should be considered because they are material and are not projected to decline in the absence of targeted mitigation measures.

DOE's proposed standard already includes certain downstream activities, including safe delivery and sequestration of CO2. This implies that project developers – particularly those receiving public support – should assume responsibility for their byproducts past the point of production. Like CO_2 and methane, hydrogen emissions are a byproduct of hydrogen production and must be accounted for as it becomes technically feasible to do so. DOE's hydrogen hubs FOA echoes this logic and notes the importance of mitigating hydrogen losses, stating that "any emissions or criteria pollutants associated with transport, delivery, and distribution will factor into the LCA of the H2Hub."

Additionally, the types of sensors required to monitor hydrogen leakage at sufficient precision and frequencies are still in the early demonstration stage. However, they are likely to become commercially available on a similar timeframe as hydrogen hub deployment. Thus, DOE should note in its CHPS (as it does in the hydrogen hubs FOA) the importance of hydrogen emissions and an intent to empirically account for hydrogen emissions in LCAs once it becomes technically feasible to do so. This includes ensuring that the necessary reporting and verification structures and calculation tools (like GREET) are capable of incorporating hydrogen emissions, as well as considering the use of interim hydrogen emissions rate estimates for different production processes and life cycle phases that can be incorporated into project developers' LCAs.

Upstream Emissions

EDF applauds DOE's inclusion of upstream Scope 2 emissions from energy consumption. As discussed in a previous stakeholder letter, overlooking these emissions would incentivize hydrogen resources that pose serious climate risks – including steam methane reformers that source gas linked to high methane

[22] IPHE, pg. 25, https://www.iphe.net/_files/ugd/45185a_ef588ba32fc54e0eb57b0b7444cfa5f9.pdf

leakage, as well as electrolyzers powered by fossil-fuel based electricity generation. For example, an electrolyzer powered by the average U.S. electricity grid mix would register a carbon intensity as high as 20 kg CO_2/kg H2 – nearly double the carbon intensity of today's incumbent and unmitigated gas-based hydrogen production pathway.

GWP Time Horizons

IPHE does not prescribe which time horizon is used in a LCA – rather, it leaves it as "a chosen time horizon." While GWP100 is the more commonly utilized metric, it hides the near-term potency of short-lived gases like methane and hydrogen. Given that the impacts of climate change are already perceptible across societies and ecosystems on every continent and in every ocean, we must minimize near-term warming as much as possible to limit further damage.[23] It is important to standardize the use of additional metrics, such as GWP20, that convey the near-term impacts of hydrogen use.

Incorporating 20-year time horizons into LCAs can easily be done, utilizing GWP factors 80 (83 if fossil origin) for methane, and 33 for hydrogen. DOE should work with the Argonne National Laboratory to better integrate this capability in GREET and require hydrogen producers calculate and report an alternative LCA using GWP20.[24]

Evaluation Cycle

IPHE recommends that hydrogen LCAs be conducted at least yearly.[25] DOE should not only require an initial LCA to determine alignment with the CHPS, but it should specify that this evaluation must take place every year and anytime there is a material change in the hydrogen production process to remain compliant.

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?

DOE should ensure it is accounting for full lifecycle greenhouse gas emissions from biogenic resources in a way that is consistent with the IRA definition. This means accounting for upstream fugitive emissions, including those which occur prior to processing. The IRA defines "lifecycle greenhouse gas emissions" as "the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the [EPA], related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to

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[23] Sun, Tianyi, *et al*., 2021. Path to net zero is critical to climate outcome. *Scientific Reports* 11, https://www.nature.com/articles/s41598-021-01639-y; and Ocko, Ilissa *et al.* Unmask temporal trade-offs in climate policy debates. *Science* 356, 492–493 (2017), https://www.science.org/doi/10.1126/science.aaj2350.

[24] GREET currently includes a GWP20 option, but it's not a default option and is difficult to incorporate into LCAs.

[25] IPHE, pg. 27-28, https://www.iphe.net/_files/ugd/45185a_ef588ba32fc54e0eb57b0b7444cfa5f9.pdf

the ultimate consumer[.]"[26] For certain biogenic resources, like landfill gas from municipal solid waste landfills, there are significant upstream emissions that occur during generation, collection, and distribution that DOE should accurately account for.

EPA's Waste Reduction Model (WARM) is a tool that estimates the potential greenhouse emissions, energy savings and economic impacts of waste management practices, including source reduction, recycling, combustion, composting, anaerobic digestion, and landfilling.[27] The model calculates emissions, energy units and economic factors across a wide range of material types commonly found in municipal solid waste and could be used by DOE to help evaluate lifecycle emissions from municipal solid waste. Further, methane emissions from landfills are already reported to EPA's Greenhouse Gas Reporting Program (GHGRP),[28] and this data provides another tool DOE can use to help estimate upstream emissions from landfill gas used to produce hydrogen. Landfill gas capture and collection systems can experience leaks and failures like those in natural gas infrastructure, and the resulting emissions should be accounted for by DOE.[29] Finally, we encourage DOE to require landfills supplying gas used for clean hydrogen production to follow a defined set of best practices for reducing methane emissions (e.g., optimizing well density, minimizing the active work face, using biocover materials, and installing emissions monitoring technology).[30]

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?

To verify emissions from hydrogen deployments, DOE should require emissions monitoring, reporting and verification across the value chain. While this is already feasible and should be required for certain segments of the value chain (e.g., methane leakage from oil and gas production as described in 3b. below), other segments may require the use of models and other estimation tools (e.g., hydrogen leakage).

To help assess whether a deployment aids in achievement of the CHPS, DOE can look to existing emissions and activity data in EPA's Greenhouse Gas Reporting Program (GHGRP).[31] While there are known issues of under-reporting for certain sectors within the GHGRP,[32] it provides a foundation for generating emission estimates based on reported data that DOE could work with EPA to improve for use

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[26] IRA Section 45V. Credit for Production of Clean Hydrogen (cross referencing Clean Air Act section 211(o)(1) (42 U.S.C. § 7545(o)(1)(H).

[27] EPA, Basic Information about the Waste Reduction Model (WARM), https://www.epa.gov/warm/basic-information-about-waste-reduction-model-warm.

[28] 40 C.F.R. Part 98, Subpart HH. Current reporting requirements, however, significantly underestimate actual observed emissions. We encourage DOE to work with EPA in updating reporting methods for accuracy.

[29] *See* EDF Comments on Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36,920, at 55, https://blogs.edf.org/energyexchange/files/2022/10/EDF-GHGRP-Comments-10.6.2022-Final.pdf.

[30] Ebun Ayandele et al., RMI, Key Strategies for Mitigating Methane Emissions from Municipal Solid Waste (July 2022), https://rmi.org/insight/mitigating-methane-emissions-from-municipal-solid-waste/.

[31] Greenhouse Gas Reporting Program (GHGRP) - https://www.epa.gov/ghgreporting

[32] Rutherford et al., Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas.

in this context. Greenhouse gas emissions from a wide variety of sectors report emissions to this program and can be used to help estimate actual emissions from hydrogen deployments.[33]

GHGRP data, however, is not fully comprehensive—not all facilities are required to report, not all sectors are covered, and emissions of hydrogen are not currently reported. And, in many cases, reported data is not based on actual monitoring and measurement. We therefore recommend that DOE use this data when it is available and accurate but supplement it with additional information (e.g., hydrogen production flow chart, list of raw materials for hydrogen production and their associated GHG emissions, energy metering system diagram, etc.) whenever necessary. And while emission estimates reported to the GHGRP are useful in the near-term, DOE should ultimately ensure CHPS is achieved in practice through verification procedures, including periodic monitoring and measurement of actual emissions.

Oil and gas facilities that would likely supply natural gas to future commercial-scale deployments of blue hydrogen already report their methane emissions data to the EPA through subpart W of the GHGRP. These reporting protocols, which are currently under revision and must be further updated in accordance with a Congressional directive in the IRA,[34] provide data that can be used in assessing upstream emissions of blue hydrogen deployments. DOE should also consider requiring more rigorous monitoring and reporting of upstream methane emissions for facilities supplying natural gas used to make blue hydrogen. (See response to 3b for more details.)

In addition to reporting on upstream methane emissions, the GHGRP requires hydrogen production facilities to report CO_2, methane, and N_2O emissions. Reporting facilities include "process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks."[35] We encourage DOE to work with EPA in evaluating these reporting requirements and consider whether additional revisions to hydrogen production facility reporting standards are necessary for accuracy and to encompass emerging forms of production.

DOE should also analyze upstream GHG emissions from electricity used to produce hydrogen. This may require working with EPA to require reporting of electricity consumption data. EDF recently recommended that EPA require reporting of data on energy consumption by facilities that are already subject to reporting requirements under the GHGRP, as well as by facilities that meet certain thresholds for overall energy consumption and/or energy-use capacity (depending on the type of facility).[36] In collecting this data, we recommend distinguishing between purchases of electricity and other forms of energy, and for electricity specifically, gathering data on a wider range of attributes.

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[33] We note that for certain sectors, only larger facilities are required to report (those emitting >25,000 CO2e). Therefore, GHGRP data may not capture all emissions, and in these cases, DOE should use other available tools to supplement and ensure accuracy.

[34] *See* 42 U.S.C. § 7436(h) (directing EPA to "revise the requirements of subpart W . . . to ensure the reporting under such subpart, and calculation of [the methane waste charge], . . . accurately reflect the total methane emissions and waste emissions from the applicable facilities" by August 2024).

[35] 40 C.F.R. Part 98, Subpart P- Hydrogen Production, https://www.ecfr.gov/current/title-40/part-98/subpart-P

[36] *See* EDF Comments on Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36,920, at 80, https://blogs.edf.org/energyexchange/files/2022/10/EDF-GHGRP-Comments-10.6.2022-Final.pdf; *see also id.* at 9-14 (explaining how such reporting could apply to electrolysis facilities).

In addition, reported GHG emissions data should be publicly available through a web-based data repository to maintain easy accessibility and transparency, so that organizations are able to track progress over time and identify opportunities to further reduce pollution.

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?

Rigorous assessment of upstream methane emissions data is vital to ensure that LCA outcomes are both comprehensive and accurate, potentially affecting both hydrogen hub funding and production tax credit eligibility. To enable this, fossil fuel-based hydrogen hub developers should be required to identify the basin(s) from which their gas is sourced and provide verified, company-specific emissions data. This is already a common practice among purchasers of natural gas and is critical for ensuring hydrogen production meets the CHPS.[37]

We recommend two pathways for ensuring developers use accurate upstream methane emissions data in determining rates specific to their deployment. First, developers could use methane emissions data reported by oil and gas companies to subpart W of the GHGRP. The IRA recently directed EPA to update these methods to ensure reporting is based on empirical data to improve the accuracy of both the basin averages and individual company data. DOE can and should work with EPA working to improve the accuracy of emissions methane emissions reporting through subpart W. Alternatively, DOE could set forth independent monitoring, reporting, and verification (MRV) standards for facilities and developers supplying natural gas to hydrogen deployments, building from existing protocols.

Pathway A: GHGRP Data

Methane emission data reported to the GHGRP could be used to ascertain fugitive emission rates associated with natural gas used in hydrogen deployments. However, for this data to be accurate, certain improvements to subpart W reporting are required. EDF recently recommended a three-step process for updating subpart W so reporting is empirically-based and accurate.[38] First, EPA should compile representative site-level measurement data by major production basin. Second, EPA should work with other relevant federal agencies to develop independent, routine, top-down estimates of total emissions by major production basin. And third, EPA should reconcile the two data sets to generate default site-level emission estimates to be used by reporters alongside the existing source-level estimates. Reporters could also follow EPA-defined protocols for collecting and submitting their own measurement data to demonstrate emissions lower than the site-level defaults.

The resulting basin-specific site-level emission estimates (which would be periodically updated to account for increases or decreases in emissions) would help ensure an accurate understanding of upstream methane emissions. This reporting structure would also allow and incentivize operators to directly measure and report emissions from their facilities, which can be used to demonstrate their better performance. Developers of hydrogen production facilities would be required to use natural gas

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[37] Differentiated gas: Nothing but hot air without these five criteria (edf.org)

[38] For more detail on the recommendations see EDF Comments on Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, at pages 19-22, available at: https://blogs.edf.org/energyexchange/files/2022/10/EDF-GHGRP-Comments-10.6.2022-Final.pdf

suppliers' data reported to subpart W under this framework to ascertain the upstream methane emissions rate from the gas they use.

Pathway B: Independent MRV

If subpart W is not rigorously updated as described above, we recommend instead that gas used for hydrogen production under CHPS be subject to independent monitoring, reporting, and verification (MRV) requirements. Ensuring that natural gas is produced and transported with low methane emissions is challenging, and existing certifications for differentiated gas (also called responsibly sourced gas (RSG) or certified gas) may not be rigorous enough to ensure CHPS is achieved in practice.[39] To credibly ensure gas is produced with low methane emissions, comprehensive direct measurement and independent verification and transparency around intensity calculations are needed. Below we outline three criteria that are critical to ensuring gas is produced with low methane emissions.

1. Require and verify that best practices and regulatory standards are met. Voluntary actions cannot be viewed as substitutes for rigorous work practice regulatory standards, measurement and reporting requirements, or any mandated comprehensive and stringent measurement-based methane emission policy. Regulations mandating work practice standards (i.e., technology and operational standards) provide foundational reductions in both methane and local environmental pollutants across all producers. DOE should support such standards by ensuring gas producers can demonstrate compliance with existing work practice standards.

2. Methane emission estimates and intensity calculations must be based on high-integrity monitoring and reporting consistent with Oil and Gas Methane Partnership (OGMP) 2.0 Level 5. The OGMP 2.0 Framework provides guidance on integrating bottom-up and top-down direct methane measurements and reporting emissions. The highest reporting tier, Level 5, includes requirements for all sources of methane emissions and requires direct measurement at both the source and site level, including methane emissions from vented, fugitive and incomplete combustion emissions. Covered emissions should also include intermittent emissions, both intentional and those due to abnormal process conditions. The latter is especially important as they can cause events with extremely high emissions. If EPA's subpart W reporting protocols are updated as described above, that data could also be used for determining emissions and intensity.

3. Reported emissions must be accompanied by verification from a credible and independent third party. There should be an established process by which verifiers are accredited by a respected and knowledgeable body that attests to the verifier being able to carry out accurate verification of an operator's reported emissions. Reported emissions should also be validated against top-down measurement data. DOE, EPA, and other relevant federal agencies (e.g., NOAA) should work together to perform, coordinate, and oversee routine top-down measurements covering most oil and gas producing regions that account for the overwhelming majority of oil and gas production. Top-down approaches should be based on a set of previously peer reviewed, scientifically robust approaches including aircraft, towers, and satellites. Top-down approaches should incorporate robust attribution methods that allow for separating emissions between oil and gas and other methane sources.

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**

[39] Lackner & Mohlin, 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.

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?

EDF supports NRDC and RMI's comments on the importance of developing a rigorous renewable electricity accounting framework for grid-connected electrolyzers that ensures system-wide GHG emissions. We present key highlights below.[40]

Grid-connected electrolyzers will need to rely on mechanisms like energy attributes certificates (EACs) and power purchase agreements to offset their emissions. However, not all clean EACs are made equal – and any such book-and-claim system must reduce effective, system-wide greenhouse gas emissions.

We recommend DOE implement a two-step approach committing to effective accounting pillars for grid-connected electrolyzers. In the near term, DOE should use the GREET model to assess hydrogen projects' carbon intensity – using either the grid average for a grid-connected electrolyzer, or a site-specific number for on-site projects. In the medium term, DOE should create a technical working group (including EPA, EIA, and Treasury) to establish a robust electricity emissions accounting framework.

Such a framework should, at minimum, meet the following requirements:

- It should have sufficient rigor and stringency to avoid emissions increases on the grid and deliver on the requirement to reduce effective GHG emissions;
- It should be implementable by relevant agencies of government, including the DOE; and
- It should have a measure of certainty and practicality for industry so as not to hinder the economics and market lift-off of grid-connected electrolytic hydrogen.

Given these requirements, the following three key principles are critical for ensuring a truly low emitting regime of green hydrogen production.

- **Additionality**: To offset emissions linked to new grid power consumption, electrolyzers must contract *new* clean generation to match this load. If electrolyzer loads are not paired with new clean generation, the grid will respond by ramping fossil generators to serve the new load, which could substantially increase net emissions.
- **Regionality**: An emission accounting framework should incorporate relevant spatial variability in power system dynamics and grid congestion, and impose operational guardrails to ensure clean energy resources powering electrolyzer loads are located in a region that allows for reasonable electricity delivery.
- **Granular Temporal Accounting**: The more granular the time period (i.e., hourly matching), the more assurance regulators and policymakers will have that hydrogen producers are effectively offsetting induced emissions from their grid-connected power electrolyzers with clean energy resources operating in real time. As solar and wind generation increases on the grid, the daily variation of grid emissions increases – thus sub-daily measurements are required for accurate emissions accounting.

4. Additional Information

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

[40] For additional details on these three key principles, please see comments submitted by NRDC and RMI.

Transparency

DOE's draft CHPS does not comment on the reporting process and level of transparency around LCA estimates. It is critical that these estimates be made publicly available, particularly for hydrogen hubs receiving funding.

The hydrogen economy is still in its infancy, and hydrogen hubs are intended to be industry leaders – opportunities to test concepts, demonstrate viability and refine processes before large-scale deployment. They need to show what is feasible, so that other projects can replicate the successes. Keeping LCA estimates proprietary prevents crucial learning from happening and negates the IIJA objective of "demonstrably aiding achievement" of the CHPS.

DOE also notes that the 5-year revision of the CHPS will be informed by data from demonstration and deployment projects – failure to make LCA information public would severely limit the discussion around feasibility and impede future ambition as the CHPS evolves.