**Date:** November 14, 2022

**From:** Dr. Michael E. Webber, Josey Centennial Professor in Energy Resources, Mechanical Engineering, The University of Texas at Austin

**To:** Cleanh2standard@ee.doe.gov

**Re:** U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance

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**Introduction**

In this memo, you will find key thoughts to consider regarding the Department of Energy's request for comment on CHPS Draft Guidance. In summary:

1) The definition of Clean Hydrogen should allow hydrogen composition with up to 10% non-GHG inert gases. This provision would allow for additional production pathways to achieve the ultimate goal of decarbonizing hydrogen production in a clean way from non-traditional sources. These non-GHG inerts can include species such as gaseous nitrogen but also helium, which has important national security value.
2) One of the benefits of GREET is that it is an industry-standard, scientifically-credentialed tool; however, it only considers a narrow subset of hydrogen production pathways. GREET should provide the opportunity to add or create additional pathways for emerging hydrogen technologies, otherwise the tool—despite its benefits—will unintentionally inhibit significant innovations that are not already included in its existing inventory of traditional, older vintage pathways. These new potential production pathways include pyrolysis, catalysis, radiolysis, photoloysis (e.g. photoelectrochemical, photobiological), biochemical reactions, redox reactions, and geological hydrogen (aka natural hydrogen, which is subsurface generation and reserves of hydrogen from geological, geochemical, or other natural pathways).
3) Geologic Hydrogen[1,2], hydrogen produced from subsurface resources via natural or geologic processes, and purified from other gases, should be considered as all hydrogen guidance and rules are drafted.

**Respondent Biography**

Dr. Michael E. Webber is the Josey Centennial Professor in Energy Resources at the University of Texas at Austin and CTO of Energy Impact Partners, a $3 billion cleantech venture fund. From September 2018 to August 2021, Webber was based in Paris, France where he served as the Chief Science and Technology Officer at ENGIE, a global energy & infrastructure services company. Webber has conducted research with support from and in collaboration with the U.S. Department of Energy, including multiple national laboratories (Sandia National Lab, NREL, Idaho National Lab, Pacific Northwest National Lab), and Oak Ridge National Lab). In addition to authoring or co-authoring multiple peer-reviewed papers and reports on the topic (including two recent articles on geologic hydrogen noted in this submission),

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[1] "Hydrogen Straight from the Earth," by Michael E. Webber, *Mechanical Engineering Magazine*, February 2021. Source: https://www.asme.org/topics-resources/content/energy-blog-hydrogen-straight-from-the-earth [Accessed November 14, 2022]

[2] "Natural Hydrogen: A Geological Curiosity or the Primary Energy Source for a Low-Carbon Future?", by I. Moretti and Michael E. Webber, "Renewable Matter, January 8, 2021. Source: https://www.renewablematter.eu/articles/article/natural-hydrogen-a-geological-curiosity-or-the-primary-energy-source-for-a-low-carbon-future [Accessed November 14, 2022]

he also oversaw a large corporate research lab dedicated to hydrogen. Webber's expertise spans research and education at the convergence of engineering, policy, and commercialization on topics related to innovation, energy, and the environment. He was selected as a Fellow of ASME (the American Society of Mechanical Engineers) and as a member of the 4th class of the Presidential Leadership Scholars, which is a leadership training program organized by Presidents George W. Bush and William J. Clinton. Webber has authored more than 550 publications, holds 6 patents, and serves on the advisory board for Scientific American and the Technical Review Panel of NREL's Energy Systems Integration division. Webber holds a B.S. and B.A. from UT Austin, and M.S. and Ph.D. in mechanical engineering from Stanford University. He was honored as an American Fellow of the German Marshall Fund and an AT&T Industrial Ecology Fellow on four separate occasions by the University of Texas for exceptional teaching.

**Responses**

**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.**

No Comment

**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?**

I consider GREET to be the standard-bearer for this kind of analysis. GREET's default estimate of fugitive emissions in upstream extraction, processing, and transportation of natural gas is likely a good average for the US as a whole. Recent work has shown actual values will have significant dependence on whether a natural gas stream is an associated gas stream from oil production, i.e. Permian basin, or a natural gas-only play, i.e. Marcellus. Data suggests that natural gas-only plays have significantly lower upstream fugitive emissions because the well, wellpad equipment, and gathering equipment can be designed fit-for-purpose. I believe that producers of clean hydrogen should be empowered to select either a reference value for fugitive natural gas leaks based on verified, measurement-based emissions performance from their suppliers or to have an option to acquire or contract gas produced at a verified higher standard. This approach would incentivize producers to improve technology for monitoring and controlling fugitive methane emissions.

GREET should disregard non-GHG inert fractions for its energy density basis. Those inerts (e.g. helium) are often of important national security value. Furthermore, though GREET is rigorous, its inventory of production pathways is limited to older, less advanced methods such as electrolysis or reformation; this limitation might accidentally cause other nascent production pathways (e.g. radiolysis, photolysis, pyrolysis, geologic, catalysis, biochemical, redox reaction cycles, etc.) to be excluded from proper consideration, which would inhibit innovation beyond the older entrenched methods.

The GREET supporting documentation should show the volumetric leak rates, gas compositions, and allocation to natural gas and natural gas liquids.

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

Figure 1 appears to presume that energy inputs for each type of energy source are counted including process fuel, natural gas, grid power, renewable natural gas (RNG), renewable power, etc. The analysis should be consistent with a correct carbon balance. For example, $CO_2$ emissions from a process with natural gas inputs and methanol outputs are not proportional to energy consumption. This analysis is correctly reflected in GREET.

The state of the clean hydrogen at plant gate should be defined to ensure that all producers are treated similarly and to provide a standard "baseline" hydrogen product. It would be good for a clean hydrogen product to be defined as hydrogen gas at 250 psig pressure or higher, where the gas composition includes a maximum of 0.1% carbon-containing gases and a maximum of 10% of inert non-GHG gases (nitrogen, helium, etc.). All energy and emissions required to produce clean hydrogen that satisfy these requirements should be accounted for in the Lifecycle Analysis. However, energy and emissions associated with any conversion of or transportation of clean hydrogen downstream of the plant gate should not be accounted for in the lifecycle analysis.

**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?**

No comment.

**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?**

The indirect GWP of hydrogen should be further studied by a wider array of investigators, and GWP of hydrogen emissions should ultimately be considered using the same 100-year impact that is applied to fugitive methane emissions and $CO_2$ emissions in the GREET model. Airshed modeling that considers diffusion, buoyancy, escape velocity, and potential local saturation should be further developed to improve accuracy of $H_2$ GWP estimates.

I also believe that measurements should replace estimates wherever possible.

Technology for monitoring hydrogen emissions from pipelines, compressors, production facilities, liquefiers, compressed delivery trucks, and other elements along the supply chain are nascent, but a program supporting the long-term growth of the hydrogen industry should also be focused on detection and mitigation of such leaks. Hydrogen-rich natural gas extraction from hydrogen-rich formations and possibly even some coalbeds, cratons or other geological features ("geologic hydrogen") could result in some level of natural hydrogen emissions or fugitive upstream hydrogen emissions and monitoring tools similar to natural gas emissions detectors should be developed so that hydrogen producers are not falsely penalized for those unrelated natural releases. Hydrogen is not as easily detectable using standard IR camera technology, but there may be methods using different spectroscopic approaches, electrochemical devices or other tools.

Any future standards around hydrogen emissions estimates should be applied uniformly across the various production methods such that all producers are operating on a level playing field and incentivized to engage in best practices to reduce emissions.

**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?**

No comment.

**2)Methodology**

**a)The IPHE HPTF Working Paper ([https://www.iphe.net/iphe-working-paper-methodology-doc-oct-2021](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?**

No comment.

**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 CO2emissions, especially given scenarios wherein biogenic waste stream-derived materials and/or( 19Paulot, 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?**

No comment.

**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?**

Allocation methods are a critical component of life cycle analysis, as energy inputs and emissions are distributed towards other products and co-products thereby reducing the carbon intensity of hydrogen. The life cycle analysis method should reflect the environmental impact of the production process which is described in the ISO standards cited by DOE.

Many allocation methods are considered within LCA frameworks. These include substitution or displacement as well as mass, energy, or economic allocation and even consequential LCA. Given the reference to GREET in the IRA, the frameworks within GREET would be appropriate choices for allocation methods. This constraint eliminates consequential LCA approaches such as those used under the EPA RFS which are also controversial and complicated to evaluate. The ISO standards recommend avoiding partitioning/allocation of the system that produce multiple products by instead "expanding the product system to include the additional functions related to the co-products" (ISO 14044, sec. 4.3.4.2).Note that this ISO recommendation is the same approach described above as "substitution or displacement".

The system expansion or substitution approach is recommended under ISO 14044 because it represents most closely the environmental impact of the co-product. Challenges to the substitution method include situations where the life cycle of the co-product is unknown. The co-product must be sold or productively used in order for a substitution credit to be valid. The constraint regarding sales of co-products has been implemented under the California Low-Carbon Fuel standard (LCFS) where evidence of sales of electric power, corn distillers grains from ethanol, and glycerin from biodiesel are required. Note that factoring co-products into allocation methods also requires the productive use of the material. The substitution method is implemented in numerous pathways in GREET as well as regulatory frameworks. Most notably corn DGS as well as export electric power from sugarcane ethanol receive substitution credits under the LCFS and this approach is the primary method available in the GREET model.

The analysis effort should allow for useful co-products from hydrogen production such as steam, electric power, high value chemicals, elemental carbon, and exotic materials such as helium. Upstream life cycle data for materials that are not in GREET are available from commercial life cycle databases.

**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)?**

Refer to 2c above

**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?**

For simplicity, GREET-based averages with the option to adjust such averages through detailed monitoring and verification programs make the most sense. Regulators should conduct periodic system-level spot checks to update and solidify such averages and determine whether they are appropriate or require adjustment.

**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?**

Acquiring natural gas from a pipeline would require significant accounting and monitoring to achieve an accurate level of fugitive emissions data from all producing assets feeding that pipeline. It isn't feasible to have unique fugitive emissions rates at various points along pipelines in different regions, especially since purchase contracts may span broad regions. Rather, developers should have an option to utilize a GREET average value, or through direct purchase agreements with producers, acquire a "certified" gas, a "responsibly sourced gas" product, or a biogas, for their feedstock. The onus would be on that specific producer to monitor and show fugitive emissions data every year to certify the lower emissions rate. Entities such as GTI Energy (formerly known as the Gas Technology Institute, on whose board I serve) are developing standards for gas certification that could potentially be used.

**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?**

Renewable energy credits, power purchase agreements, or other market structures should be allowable, but with common sense restrictions that prevent double crediting and that prevent producers from pushing the carbon impact of electricity on a regional grid to other users. Recommended restrictions would be the following:

(1) RECs should be available for renewable power produced in real time. Given the variability inherent in electricity supply and the high cost of electricity storage, RECs should not be bankable across hours in the same grid (i.e., a H2 facility should not be able to buy solar RECs and consume the power at midnight without accounting for storage).
(2) RECs should be available only on the basis of "additionality" – if a new electrolyzer is constructed consuming 100 MW, then RECs should be used if 100 MW of renewable capacity is added to the grid to supply it with power. For example, it would be counter to the CHPS' aims if electrolyzers that facilitate an extension to a coal plant's lifetime can use RECs as part of their accounting.
(3) RECs should only be available within the same balancing region, for example, wind power added in Wyoming should not be available for use by an electrolyzer in Florida.

These restrictions will lead to a more rational hydrogen economy where the criticality of grid-balancing and hydrogen storage is appropriately valued; otherwise, the burden of a very challenging problem would simply be shifted to grid operators, ultimately driving up the cost of power for the public.

**d)What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0kg$CO_2$e/kgH2)?**

The minimum fully burdened cost of transitioning from the relatively high carbon impact of contemporary steam methane reformed hydrogen to clean hydrogen with less than 4kg$CO_2$e/kg$H_2$ is approximately $400-500/tonne H2 on top of typical production costs, which includes additional operating costs and return of capital for capturing $CO_2$ from an autothermal reformer, transporting it, sequestering it, and monitoring it, while purifying the resulting hydrogen stream to meet a clean hydrogen standard. Costs increase substantially in most methods to get to lower carbon impact values, where electrolysis is viewed to be the most obvious option.

A different possibility is presented by the concept of geologic hydrogen, where hydrogen may be produced from subsurface resources and purified from associated gases using standard gas processing equipment. Such hydrogen would match or exceed the low CI of electrolyzers while addressing the challenges around use of intermittent renewable energy to produce hydrogen which is widely used by customers with baseload demand.

**4)Additional Information**

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

GREET is a powerful tool to measure success in our adoption of new hydrogen technologies to decarbonize the planet. To this end, GREET should provide the opportunity to add or create additional pathways for emerging technologies not currently provided for. A format or structure for the submission of said additional pathways would be beneficial to all.

A mechanism with which to show GREET equivalence for external models should be created.

Finally, I recommend publishing Well to Pump emission factors (upstream plus end use for various components of interest).