Submitted by email to Cleanh2standard@ee.doe.gov
Response to DOE on U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance

Shell is pleased to offer these comments in response to the Department of Energy's (DOE) initial proposal for a Clean Hydrogen Production Standard (CHPS). Shell believes that the carbon intensity of hydrogen should be based on a life cycle analysis, technology and feedstock agnostic, and that the carbon intensity reduction be relative to today's emissions. Further, the methodology used by CHPS should align with international efforts to ensure that domestic decarbonization efforts remain competitive and serve as a platform for the US to be a leader in the adoption of hydrogen.

It is important the CHPS provides flexibility to pursue project specific carbon reduction methods. As CHPS is based on a lifecycle system boundary model of carbon accountability, project developers should have the ability to improve emissions along the entire value chain. Shell also agrees with forecasts of the Credit for Production of Clean Hydrogen (now 45V), which state that volumes from green hydrogen will take a significantly longer time to materialize at scale in comparison to those from blue hydrogen. The technology of blue hydrogen production is proven and already deployed at scale (ex. steam methane reforming, partial oxidation technologies (POx), and carbon capture and storage). It is for these reasons that we expect blue hydrogen projects to be the dominant solution in the near-term that can provide utility as founding anchors of H2Hubs. While this near-term deployment of blue hydrogen is an important opportunity to reduce greenhouse gases, significant additional benefits will flow to and accelerate the development of other forms of hydrogen production. One such benefit is that blue hydrogen provides the pathway to underwrite the buildout of hydrogen infrastructure including storage, pipeline, and transportation that will serve as the backbone of the clean hydrogen industry. This infrastructure will enable markets for green hydrogen as the technology stack matures and potentially becomes the leading solution at larger scale. Shell is actively pursuing blue and green hydrogen projects with equal excitement for the potential of both solutions.

As a technology focused company, Shell is actively involved in various efforts to advance industry standards across many frontier industries. The DOE has an opportunity to foster the development and scale of clean hydrogen production through the CHPS. In hydrogen, Shell has been heavily involved in hydrogen standards work at the World Business Council for Sustainable Development (WBCSD) to support H2Zero pledges along with the forthcoming 'Guide to 1.5°C aligned hydrogen investments' paper. Further, Shell is involved in the development of the CertifHy hydrogen carbon intensity standards in the European Union. It is with this perspective that Shell provides these comments on CHPS and urges the DOE to provide flexibility in its standard to promote investment in clean hydrogen production. We appreciate the opportunity to participate and look forward to continuing to serve as a resource.

Yours sincerely,

Eelco Gehring – Shell US Country Lead Hydrogen Industry
Shell Woodcreek Complex – 150 N. Dairy Ashford Rd, Houston, TX 77079
Email: Eelco.Gehring@Shell.com
Phone: +1 312 608 6200

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?

The default estimates contained in GREET are good representative data for the limited number of cases in the model. However, the relevant parameters used to capture these pathways will vary significantly for each individual project, even within a specific region. For example:

- Currently, GREET has only limited flexibility for the upstream greenhouse gas (GHG) intensity of natural gas (NG) production. Local natural gas pipeline networks, or contractual agreements, might allow for the procurement of lower GHG-intensity NG feedstock, both nationally and within specific regions. It should be possible to represent this in the model. For example, the inability of a project developer to benefit from a low emission feedstock like renewable natural gas (RNG), and instead be subject to regional feedstock carbon intensity scores, would represent a missed opportunity to incentivize such infrastructure investments. Non-physical instruments that recognize constraints in the market such as power purchase agreements (PPAs), renewable energy certificates (REC), and Book-and-claim are also valuable market mechanisms to incentivize decarbonization investments.

- Biomass cultivation and harvest GHGs may be significantly reduced (perhaps up to approximately 50%) by minimal nitrogen fertilizer application, or no tillage farming leading to increased soil organic carbon. On the flip side, less efficient farming practices could lead to significantly higher emissions from biomass cultivation and harvesting. These practices could be implemented independent of regional location.

- Avoided emissions from waste stream materials (potentially used to make RNG for hydrogen production) could vary dramatically within regions, depending on the end-of-life fate from which the waste has been diverted. For instance, municipal solid waste (MSW) diverted from incineration without energy recovery would likely have the greatest avoided emissions benefit, whereas MSW diverted from landfilling with efficient methane recovery would likely have a very minor avoided emissions benefit. This could vary within regions.

- Use of a PPA or other market instrument (e.g. REC) to demonstrate the use of renewable power as an input to hydrogen production would lead to a zero or no GHG source of power, which could be very different from a regional grid average.

In addition to variability between projects in the above parameters in GREET, there are several aspects of hydrogen production projects that are not easily represented in the model which will significantly impact their life cycle GHG emissions. A few examples include steam quantity and quality required as a utility input or generated as a co-product, the effective capture rate of CCS activities, and the composition of flue gases at a facility. Although editing these parameters may be possible indirectly in GREET, it is not straightforward how this can be accomplished. This could lead to divergent or erroneous results between life cycle analysis (LCA) practitioners making submissions to CHPS.

Therefore, to achieve a high degree of accuracy for the lifecycle carbon intensity of a given hydrogen production project, CHPS should allow for the representation of project specific parameters in GREET, including but not necessarily limited to:

- Well-to-gate GHG intensity of feedstock natural gas
- Imported power GHG intensity (currently GREET has grid power factors available for 10 sub-national regions, but greater regional specificity (e.g. state level) would be more accurate)
- Imported steam quantity and quality
- Other utility or material inputs (e.g. process water, cooling water, nitrogen, instrument air, oxygen)
- Quantity and quality of co-produced steam, power, solid carbon, oxygen, or other co-products
- Direct emissions or flue gas quantity and composition
- The use of non-physical instruments to reduce GHG emissions including PPAs, RECs, and book-and-claim.

Furthermore, DOE should provide guidance on exactly which parameters (tab and cell locations) may be edited to reflect specific projects, as well as the evidence required to deviate from a default assumption, parameter value, or emission factor. This would provide clarity for the submission process and help generate more consistent results under the CHPS program.

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

A hydrogen monitoring and reporting program analogous to the OGMP2.0 framework used for methane should be considered as a methodology for the future. However, the technology necessary for this methodology is not yet available as there are gaps in availability of suitable hydrogen sensors to do "top down" verification of reported emission by measurement at the site level. It would be useful if the DOE focused on helping to accelerate the development of this technology.

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?

If CO_2 captured during the process of hydrogen production is subsequently used, and is not permanently stored, the benefit of the carbon capture and use (CCU) should only be reflected in one product LCA: either the hydrogen product, or the synthetic fuel or other product using the carbon. It cannot be reflected in the LCA of both products or else there would be double counting/ claiming of the benefit.

In the case of CCU to produce synthetic fuels, this would function in the following way:

- If the CCU benefit was attributed to the hydrogen product, the captured CO_2 (net of emissions associated with capture processes) should not be included in the life cycle inventory of the hydrogen product. However, the CO_2 that is used and ultimately emitted (e.g. during combustion in the case of synthetic fuel) must be included in the life cycle inventory of the fuel product.

- If the CCU benefit is attributed to synthetic fuel, the captured CO2 should be included in the life cycle inventory of the hydrogen product. However, the CO_2 that is used and ultimately emitted (net of emissions associated with capture processes) should not be included in the life cycle inventory of the fuel product.

If this is followed, fossil CO_2 that is 'used twice' (captured during hydrogen production and used as feedstock for synfuel production) generates a benefit only for one of the two uses. It would also be possible, in principle, to enable sharing of the 'second use' benefit between the two products, but this would further complicate the documentation required to demonstrate that no double counting/ claiming is occurring.

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?

We consider the ISO standards cited above to be the gold standard and foundation for all subsequent LCA methodologies, so we strongly support the use of ISO as the basis for CHPS. Some additional standards, also built on or aligned with ISO, that may prove useful:

- GHG Protocol Product Standard
- PAS 2050
- WBCSD H2Zero Hydrogen Pledges, and WBCSD Policy Recommendations to Accelerate Hydrogen Deployment for a 1.5°C Scenario

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 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?

Use of the default data/ pathways in GREET is an excellent starting point. This could be further supplemented with use of the EPA WARM model for MSW feedstocks or GREET or CA-GREET pathways for RNG from landfills or animal manure. RNG-derived hydrogen pathways from different feedstocks should be included as an option in the GREET model.

Since these avoided emissions can, in many cases, be so significant as to dominate the overall lifecycle results, it will be important to reflect project-specific parameters in calculating the LCA of the hydrogen product whenever possible. Otherwise, there may be a significant discrepancy in LCA results reflecting a general case and the conditions of a specific feedstock source.

Furthermore, there are projects under consideration which could potentially combine biogenic resources with CCS, resulting in permanent storage of biogenic CO_2. Guidance from the DOE on how this would be treated (e.g. crediting as a 'negative' source of emissions) would be helpful for project evaluation.

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?

ISO stipulates that system expansion should be used whenever possible to avoid allocation. However, system expansion can be difficult to implement in practice because there needs to be clarity around what is being displaced from the market and the associated GHG footprint. To avoid diverging results for similar systems, the DOE should provide specific guidance on the GHG credit values tied to certain co-products when system expansion is used (similar to the approach CARB uses in CA-GREET).

In other instances, particularly when it is difficult to determine the products displaced from the market, or the co-products are energy carriers (e.g. electricity), it could be more meaningful to use energy allocation. Mass allocation rarely results in a meaningful comparison given the utility of different products, so it should only be used if system expansion is impractical and energy allocation is not meaningful for the relative utility of the products.

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)?

If the decision to produce by-product hydrogen has consequences that impact the GHG emissions of a plant, this impact should be accounted for in the LCA of the hydrogen. For example, if by-product hydrogen that is currently being used in burners is diverted from this existing use and is replaced in the burners with natural gas or another fuel source that produces GHG emissions, then such hydrogen should bear the GHG burden of the substitute fuel.

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?

A periodic auditing and verification process should be implemented, similar to CARB. Certified verifiers check actual plant operations against modeled data and update the LCA data as necessary. Aligning this with existing verification processes (like CARB) would make it much easier to implement the CHPS in practice.

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?

Developers would need to rely on the provision of data from their natural gas supplier. This is most likely either the midstream pipeline operator or integrated company who both produces and delivers the NG. Until NG suppliers are willing and able to furnish these data, developers may need to rely on generic data (from DOE studies and others) which reflect average emissions in a given NG supply network, or even national level data (such as is in GREET) if regional data are unavailable.

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

Yes, these types of instruments should be allowable. These are important mechanisms for sending a strong market signal for lower GHG intensity power generation, enabling accelerated investments in renewable capacity, while still taking advantage of the economies of scale and load balancing of grid-connected power generation. In many instances, renewable power and hydrogen generation are driven by geographic constraints that do not often overlap. For each project to be optimally located, a commercial agreement is a useful tool that facilitates development and can greatly expand the overall potential of both industries. In some circumstances, RECs generated in the same hydrogen production region could be paired with the grid electricity to produce green hydrogen through electrolysis. Hydrogen producers should be able to benefit from the rapid growth in renewable energy generation development in the near-term to encourage green hydrogen investment. RECs are verified and can be easily tied to regional production. But, while co-locating generation with electrolyzers may seem logical, it is not economically feasible to require it be part of the CHPS, given the mismatch between the intermittent nature of the generation and the base load demand of the electrolyzer. To accommodate existing or proposed co-located facilities, the CHPS can provide a multiplier for the behind the meter generation, while allowing producers to acquire regional RECs to meet the demand in hours when the on-site facility is not generating.

However, there need to be safeguards in place to ensure the benefits of renewable power are only claimed once. If a PPA is in place for the power output of a grid-connected wind farm, that power should not also be used to calculate the 'residual' average grid power GHG intensity, because this power is no longer available. This should follow the GHG Protocol Scope 2 guidance published by WBCSD and the World Resources Institute.

4) Additional Information

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

Shell supports the DOE in establishing an additional CO_2 intensity metric for evaluation of the regional clean hydrogen hubs, but the DOE must also comply with the statutory definition of clean hydrogen. In the draft guidance for the proposed CHPS, the DOE states that the lifecycle target aligns with the new clean hydrogen policy drivers established in the Inflation Reduction Act (IRA) 45V Credit provisions. The DOE should also seek to align with the IRS guidance on 45V and other relevant provisions of the IRA. Shell notes that DOE's proposed CHPS does not use the same LCA system boundary (well-to-gate) as the IRA requires for 45V. The DOE's proposed CHPS system boundary for hydrogen production methods that utilize fossil fuel includes emissions associated with CO_2 compression, transport, and storage is beyond the "well-to-gate" boundary required by 45V. The proposed CHPS also does not consider "significant indirect emissions" for all production methods as required in the definition of lifecycle analysis.

Additionally, any modeling of the lifecycle GHG emissions from hydrogen production in the GREET model should provide the flexibility to accurately represent the various technology line-ups for producing low carbon hydrogen. For example, Shell believes POx will have an important part to play in the development of a hydrogen economy. POx offers many benefits including an ability to deliver large quantities of hydrogen at scale. It is also a mature technology; Shell has significant experience and a proven track record in designing, licensing, and operating POx technology since the 1950s with over 150 POx reactors licensed, built, or operated worldwide of which around ten plants are for Hydrogen Service. Shell is actively pursuing the development of hydrogen POx projects in the US.

However, the GREET model does not currently include a technology pathway for hydrogen production from POx. This technology does not necessarily need to be represented in detail, but at a minimum there should be a generic pathway in the GREET model, which would enable the input of heat and material balances for various technology configurations and calculate the GHG emissions intensity in line with the requirements of CHPS.