

World Resources Institute  
10 G St NE, Suite 800  
Washington, DC 20002

Submitted by: Zachary Byrum and John Feldmann  
Zachary.Byrum@wri.org  
703-967-3897

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*Response to DOE request for stakeholder comments on draft guidance for a Clean Hydrogen Production Standard.*

To whom it may concern,

Thank you for the opportunity to provide input into DOE's draft guidance for a Clean Hydrogen Production Standard (CHPS), as it pertains to the implementation to the Bipartisan Infrastructure Law (BIL). As a guiding metric for the development of the BIL's hydrogen hub program, the CHPS must clearly present to program applicants the minimum carbon intensity of their proposed hydrogen production project. It is just as important to explicitly communicate the means by which applicants should or should not achieve the standard. Below, we have selected several questions from the request for comments document that the World Resources Institute hopes can inform the Department of Energy's finalization of the CHP.

1. Data and Values for Carbon Intensity

**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.**

- Embodied emissions in production and distribution infrastructure. The infrastructure required to produce, distribute, and store hydrogen could be significant given that the material needs for hydrogen containment are different from those for natural gas and other gaseous fuels, and therefore existing infrastructure would mostly have to be modified or new infrastructure would be needed.
- Land use, land use change, and forestry emissions (LULUCF). If biomass feedstocks are to be used, LULUCF emissions should also be considered. Emissions intensities vary by region and type of land use and land use change. It isn't clear whether this is being considered in the production of biomass feedstocks (labeled as "Net GHG emissions associated with production of biomass feedstocks" in Figure 1). A clear reference case for each resource (land, forest) should be determined in order to estimate this contribution. Furthermore, land use change can be due to infrastructure (facilities, pipelines, etc.).
- Methane emissions from uncapped or abandoned wells. It is estimated that 7-20 Mt CO<sub>2</sub>e are emitted from abandoned and orphaned natural gas wells annually in the U.S., and the real figure could be higher ([link](#)). These emissions should be attributed to the natural gas industry and included in leakage rates.

- Hydrogen leakage and consideration of hydrogen’s 20-yr global warming potential. Distribution and storage of hydrogen will necessarily lead to boil off and leakage, and hydrogen’s 20-yr global warming potential has been estimated to be 30-35 times that of carbon dioxide (Ocko and Hamburg 2022 [link](#)). Assuming a leakage rate of 1% for hydrogen in 2050 using DOE’s H2@Scale estimate of 80 EJ/yr of hydrogen (700 Mt hydrogen) demand would yield 7 Mt of leaked hydrogen, equivalent to 210-245 Mt CO<sub>2e</sub> due to hydrogen leakage alone.

**e. Atmospheric modeling simulations have estimated hydrogen’s indirect climate warming impact (for example, see Paulot 2021).<sup>19</sup> 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?**

- Laboratory experiments should be conducted to simulate hydrogen’s release into the atmosphere and its effects on chemical species evolution
- Monitoring at the plant level should be supported by leak detection technology and mass balance of inputs/feedstocks vs. Products/byproducts
- Monitoring of distribution and consumption should be supported by mass balance of hydrogen produced vs. delivered/consumed

**f. How should the lifecycle standard within the CHPS be adapted to accommodate systems that utilize CO<sub>2</sub>, such as synthetic fuels or other uses?**

In most applications, CO<sub>2</sub> utilization does not yield the same reduction in GHGs as dedicated storage. This is primarily due to the amount of time utilized CO<sub>2</sub> is “stored” in some pathways (e.g. beverage carbonation vs mineralized for use in cement clinker) but may also be due to the energy and feedstocks required to convert CO<sub>2</sub> into products. When incorporating CCU-products within the boundaries of the CHPS standard, what should be considered in-scope are the net emissions of processing and using CO<sub>2</sub> within the product and the use of that product. For example, CO<sub>2</sub> for chemical production should incorporate the energy required to use CO<sub>2</sub> as a feedstock balanced against the emissions of the final product’s use. However, it should not include the emissions from other parts of the products lifecycle that are otherwise unaffected by the use of CO<sub>2</sub> as a feedstock. In other words, what should be considered in-scope is the absolute net-balance of CO<sub>2</sub> use rather, for example, the relative carbon intensity reduction in the product using that CO<sub>2</sub>.

Several key utilization pathways and their LCA considerations are outlined below:

- Enhanced Oil Recovery (EOR): The National Academies of Sciences, Engineering, and Medicine (2019) consider EOR to be permanent storage, with over >99% of CO<sub>2</sub> stored without risk of leakage back into the atmosphere; leaks would likely be acute, not chronic, and thus able to be remediated.
  - Compliance with the CHPS should consider volumetric net-CO<sub>2</sub> stored of using a barrel of oil for refined fuel following CO<sub>2</sub> injection to extract that barrel on a per-ton basis.
- Mineralization: Converting captured CO<sub>2</sub> into mineral form offers effective permanence. However, mineralization into products, namely concrete production, requires changes to process energy and feedstocks. Three key variables that greatly influence the carbon intensity of

[CCU-concrete](#) are whether CO<sub>2</sub> is used for cement curing or mixing, whether supplementary cementitious materials (SCM) are used as a binder material, and the emission intensity of SCM

- Compliance with the CHPS should consider volumetric net-CO<sub>2</sub> stored within concrete following CO<sub>2</sub> processing for curing or mixing and producing SCMs.
- Chemical Production: The complexity of chemical supply chains, the relatively low maturity of CO<sub>2</sub>-use pathways aside from urea production, and the uncertain lifetime of petrochemical products like plastics complicates carbon accounting. Key factors that need to be considered are the energy requirements to use CO<sub>2</sub>, the disposal/use of the product, and where CO<sub>2</sub> was used in the product's manufacturing.
  - Urea: Produced by combining CO<sub>2</sub> with ammonia, urea is one of the largest CO<sub>2</sub>-use markets today. However, much of not all of that CO<sub>2</sub> is [re-emitted](#) after it is applied to agricultural lands, making its permanence highly dubious and unpredictable. More research is needed to fully understand CO<sub>2</sub> fluxes, but this should likely not count towards CO<sub>2</sub> storage.
  - Methanol: Methanol can be used in its current form as an intermediary or solvent, a fuel, and as a possibly sustainable feedstock for olefin and aromatic chemical production. All [production pathways](#) must consider the carbon-intensity of the energy needed to process CO<sub>2</sub> into methanol and its end-use.
    - Methanol used as fuel must incorporate combustion emissions, which would be relatively easy to account for as fuel use and can be tracked.
    - Methanol as a feedstock for inorganic products like plastic can, theoretically, be considered long-term storage (multi-thousand year lifetime) given plastic's resistance to decomposition. However, approximately 15% of plastic is incinerated, eliminating the carbon storage benefit, and landfill plastic can lead to indirect methane emissions. These uncertainties should disqualify CO<sub>2</sub>-to-methanol-plastics as a storage route.
  - Ethylene: As a plastic precursor, ethylene has the same limitations as methanol-based products.
- Synthetic fuels: CO<sub>2</sub> can be converted into fuels through several routes, both direct and indirect. Similar to EOR, their inclusion within the CHPS framework must account for both storage during production and emissions upon combustion. But unlike EOR, the CO<sub>2</sub> that is ultimately used to produce synthetic fuels—namely sustainable aviation fuel via Fischer-Tropsch synthesis—is re-emitted into the atmosphere.
  - Because CO<sub>2</sub> that is used is ultimately emitted upon combustion and additional CO<sub>2</sub> is emitted during synthetic fuel production due to energy use, this pathway would likely add to the carbon intensity of the clean hydrogen production.

## 2. Methodology

**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 byproduct hydrogen from these processes typically handled (e.g., venting, flaring, burning onsite for heat and power)?**

While extensive research on dedicated hydrogen is available, there is a paucity of publicly available data on by-product. This is likely due to the proprietary use of by-product by plants or a lack of need to report on amounts vented as a waste product. By-product hydrogen is predominately handled as outlined below:

- Refining, the largest hydrogen market, satisfies slightly less than half of its hydrogen needs with hydrogen byproduct from catalytic reforming. It is isolated from flue gas and fed into hydrocracking and hydrotreating units to upgrade and desulphurize fuels, namely diesel. It can also be recycled into process heaters for combustion.
- Steam crackers for olefin production at petrochemical plants produces not insignificant amounts of by-product that is fed back into the cracker's furnace as fuel. One study estimated that steam crackers could add [3.5Mt](#) of hydrogen to the merchant market if isolated and exported. However, that would require importing or using additional methane to meet the heat deficit lost by removing hydrogen.
- Chlor-alkali processes that manufacture chlorine create by-product hydrogen through electrolysis, which is typically powered by grid electricity or on-site combined heat and power turbines (CHP). The power source affects the product's carbon-intensity and how hydrogen is handled, with by-product mostly likely recycled if CHPs are used. [Most](#) of the hydrogen not combusted is sold to the merchant market, with smaller amounts vented, leading to indirect atmospheric warming.

The cited studies above indicate that emissions can be attributed to by-product in three ways: Substitution, mass-allocation, and market-allocation.

- Substitution: These are emissions created by substituting fossil fuels for hydrogen that is exported rather than burned on site. Importing natural gas rather than burning hydrogen on-site requires adding the emissions from isolating and exporting the hydrogen, transporting the natural gas (e.g. methane leakage, extraction), and burning the new fuel. For petrochemicals and chlor-alkali process, substitution yields an insignificant GHG reduction if using GREET's baseline carbon intensity for SMR of 9kgCO<sub>2</sub>/kgH<sub>2</sub>.
- Mass-allocation: If hydrogen is slated for export, its carbon intensity is considered to be a percentage of the total carbon intensity from the product slate according to its stoichiometric balance. Thus, if hydrogen composes 7.6% of the product slate, its carbon intensity is 7.6% of the total.
- Market-allocation: A similar proportional system to mass allocation but uses the market value of hydrogen relative to other products.

Despite the potentially large potential for by-product hydrogen in the merchant market, we do not recommend making eligible for consideration as low-carbon hydrogen for the purposes of the BIL for several reasons. 1) The BIL's CHPS aims to indicate achievement of dedicated, low-carbon hydrogen to scale up clean-hydrogen production pathways that are poised to become competitive with conventional production. 2) By-product generally produces lower emissions than conventional dedicated production but could crowd out investment for other promising, state-of-the-art, low-carbon pathways. 3) It could yield equivalent emissions if fossil fuels are substituted for combustion. 4) It could create a perverse incentive to manufacture other products (e.g. petrochemicals) to capture hydrogen revenues.

## 1. Implementation

### **d. What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0 kgCO<sub>2</sub>e/kgH<sub>2</sub>)?**

- It is estimated by NREL's H<sub>2</sub>A production models that the economics of electrolysis-based hydrogen will likely not be affected by meeting such a standard, since distributed renewable electricity electrolysis is cost-competitive and even cheaper than central grid electrolysis in some regions of the country. Therefore, allowing for the use of approximately 15% grid electricity in order for electrolysis-based hydrogen production to meet the standard will likely not affect the economics of this production route up to a certain production capacity.
- The economic impact of meeting the proposed standard on hydrogen production from natural gas using steam methane reforming would be to increase the cost of production by approximately 50% relative to hydrogen production using steam methane reforming without carbon capture, according to this [DOE NETL study](#).
- Meeting the proposed standard would not be expected to have an economic impact on hydrogen production from waste biomass feedstocks, since the standard is well above the expected emissions intensity of this production route.
- Meeting the proposed standard would not be expected to have an economic impact on hydrogen production via electrolysis at nuclear fuel facilities, since the standard is well above the expected emissions intensity of this production route.

## 3. Additional Information

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

- Recommend setting a standard that increases in stringency over time.
- Recommend setting a standard whose components (leakage monitoring, leakage mitigation, biomass feedstock requirements, renewable electricity requirements, fossil fuel feedstock requirements) increase in stringency over time.
- Recommend that the 20-yr GWP for hydrogen, CH<sub>4</sub>, and all GHG emissions be used to calculate CO<sub>2</sub>e emissions of a facility that is operating under the standard.