DOE Hydrogen Program
U.S. Department of Energy's (DOE) Clean Hydrogen Production Standard (CHPS) Draft Guidance
DATE: October 20, 2022
SUBJECT: U.S. Department of Energy's (DOE) Clean Hydrogen Production Standard (CHPS) Draft Guidance
RESPONSES DUE: October 20, 2022
SUBMITTED BY: Pacific Gas and Electric Company (PG&E)

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to submit comments in response to the U.S. Department of Energy's (DOE) Clean Hydrogen Production Standard (CHPS) Draft Guidance. DOE seeks to obtain feedback on the proposed CHPS and information on data that will inform the value of the CHPS. PG&E, a subsidiary of PG&E Corporation, is a combined natural gas and electric utility serving more than 16 million people across 70,000 square miles in - Northern and Central California. For more information, visit www.pge.com.

Please reach out to the below contact if you have questions on this submission:

Danielle Mark
Expert Gas Engineer
Danielle.mark@pge.com
925-813-8191

Or

Jamie Randolph
Principal Hydrogen Program Manager
jamie.randolph@pge.com
415-218-6979

Pacific Gas and Electric Company

COMMENTS FROM PACIFIC GAS AND ELECTRIC COMPANY ON U.S. DEPARTMENT OF ENERGY CLEAN HYDROGEN PRODUCTION STANDARD (CHPS) DRAFT GUIDANCE

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.

Based on the examples on page 3 of the CHPS, the focus is on the process emissions only. Other emissions sources include operational emissions (scheduled/planned blowdowns, components that use the fuel source within the pipe). If these are not accounted for already, do they need to be considered?

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?

There was a recently published article by the Environmental Defense Fund titled *Climate consequences of hydrogen emissions* published in July 2022[1]. The following were recommended:

- Chemistry-climate modeling to understand net effects with co-emissions from hydrogen and fossil fuel technologies, estimate climate responses to hydrogen emissions beyond forcings, assess how changing concentrations of other constituents in the atmosphere affect hydrogen's potency.
- Develop technologies to accurately measure hydrogen emissions at parts per billion (ppb) levels to improve quantification of hydrogen leakage rates

f) How should the lifecycle standard within the CHPS be adapted to accommodate systems that utilize CO2, such as synthetic fuels or other uses?

[1] https://acp.copernicus.org/articles/22/9349/2022/

- In general, for systems that convert CO2 into fuels, chemicals or building materials or directly use CO2 (e.g., in yield boosting, solvent, heat transfer fluid, other operations), it is the amount of avoided CO2 (not emitted) that should be accounted for. For CO2 conversion, the CO2 avoided should be the sum of the amount converted plus the amount not emitted from process improvements/waste reductions. For CO2 use, the CO2 avoided should be the reduction in the life-cycle emissions when compared with the product it displaced. It should displace a product with higher life-cycle emissions to result in a reduction.
- Section 45Q carbon oxide sequestration credits have a CO_2 utilization lifecycle analysis requirement to be eligible and have established a program to accommodate systems that utilize CO2. The same methodology can be followed with the addition of solid carbon as described below.
- The lifecycle standard should also account for solid carbon. For example, methane pyrolysis creates hydrogen gas and solid carbon. The solid carbon can be sequestered, converted or used directly. The CO2 avoided (not emitted) emissions should be accounted for.

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?

In seeking to quantify emissions, DOE should look to leverage existing, generally accepted tools, tailored, as appropriate, for the hydrogen industry. In general, methods of verifying GHG emissions have been developed and are used in other sectors of the energy economy. This includes third-party verifiers for the biogas industry, as well as for programs like the Low Carbon Fuel Standard and to obtain renewable energy credits. Specifically, 40 CFR Part 98 Subpart P (Hydrogen Production) requires owners or operators of facilities that produce hydrogen to collect and report GHG emissions. Procedures for GHGs to report, calculating GHGs, quality assurance, estimating missing data, data reporting and record keeping must be followed. In addition, consider third-party certification to provide an independent and nationally recognized verification of the clean hydrogen.

Pacific Gas and Electric Company

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?

The source of natural gas used at a delivery point is not typically traced back to its source in publicly available sources. This would be difficult information to accurately access for developers of hydrogen production. The data isn't readily available nor is the gas traced in detail from source to end-user in the natural gas market.

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?

- PG&E supports allowing the use of instruments such as renewable energy credits, power purchase agreements, and other market structures to characterize the intensity of electricity emissions for hydrogen production.
- Time of generation or time of use of such instruments should not constrain their ability to be tied to the electricity emissions for hydrogen production. That said, for the use of renewable energy credits (RECs), PG&E suggests that there should be a shelf life and that the RECs be required to have been generated within 3 years of its use by a hydrogen producer.

The geographic source of the RECs or power purchase agreement (PPA) tied to the hydrogen production facility should be broadly defined, given that greenhouse gases are a global pollutant. It should be determined which REC tracking systems can be used for verifying retirements for hydrogen production and then those tracking systems can have their own geographical coverage areas. For example, the Western Renewable Energy Generation Information System (WREGIS) covers the Western United States, and so hydrogen producers in the Western United States could be required to procure RECs that are tracked in WREGIS (using RECs tracked in WREGIS also conforms with California Renewables Portfolio Standard eligibility requirements).