December 1st, 2022

DoE Clean Hydrogen Production Standard Draft Guidance

Position of TotalEnergies

TotalEnergies welcomes the ongoing public consultation on the initial proposal of the Department of Energy for a Clean Hydrogen Production Standard (CHPS), developed to meet the requirements of the Infrastructure Investment and Jobs Act of 2021 and that can be aligned with the requirement of the Inflation Reduction Act. This memo presents the general observations of TotalEnergies regarding the draft CHPS.

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1) Data and Values for Carbon Intensity

a) Our estimated values in the next 5-10 years for the parameters that can influence the lifecycle emissions of hydrogen production are listed in the Appendix.

b) How accurate are the estimates default values in GREET of the carbon intensity for parameters that are not likely to vary widely by deployments in the same region[1]? What are other reasonable values for these estimates? what are the uncertainty ranges associated with these estimates?

We consider that the default values of GREET are sufficiently representative of the regionalized production in the US. However, it is advisable to leave the possibility of a calculation based on real data.

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 shows all key emissions sources associated with feedstock extraction or production, generation of electricity, feedstock delivery, hydrogen production, potential releases during CO2 transport, and carbon capture and sequestration of GHGs generated by the production process. In the context of hydrogen production, it would however be relevant to add the emissions of the water treatment to have a full well-to-gate life cycle assessment. This principle would be applicable whichever technology is being used (electrolysis, steam methane reforming, etc.)

d) 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?

TotalEnergies has developed a solution to monitor in real time GHG from a company down to individual equipment level. The tool provides key information empowering operators to look for CO2 reduction opportunities at different levels on their facilities. Actions can be compared to quickly quantify impact with a view to retain only the most effective. This could be a best practice to mitigate emissions downstream of the site of hydrogen production and potential CO2 leakage.

[1] E.g. carbon intensity of regional grids, net emissions for biomass growth and production, avoided emissions from the use of waste-stream materials.

e) What types of data, modeling or verification methods could be employed to improve effective management of the indirect climate warming impact of hydrogen?

Regarding the indirect climate warning of hydrogen, it is important that these analyses are carried out by a third-party organization like a DoE laboratory. The Hydrogen Council is currently working to provide clarity on climate impact of hydrogen releases/leakage.

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

Hydrogen can be used directly as a fuel as well as to produce synthetic fuels for the maritime or aviation sector by adding CO2 in a Fischer–Tropsch process. The CO2 incorporated in the chemical composition of a synthetic fuel can come from three distinct sources: (i) the CO2 is of fossil origin and has been captured from an industrial site (e. g. a refinery), (ii) the CO2 is atmospheric and has been captured with direct air capture technologies (DAC) or (iii) the CO2 is of biogenic origin and comes from the production or combustion of biomass.

For TotalEnergies, it is important that in the calculation of the life cycle analysis for a synthetic fuel, the captured and reused fossil CO2 benefits from a CO2 credit during a transition period to ensure scale-up. Without this credit, synthetic fuels would have no economic value for the consumer. Regarding biogenic CO2, it will be necessary for the CHPS to clarify the issue of net negative emissions pathways.

2) Methodology

a) What are the benefits and drawbacks to using these recommended ISO frameworks (14067, 14040, 14044, 14064, and 14064) in support of the CHPS? What other frameworks or accounting methods may prove useful?

The International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) refers to several ISO frameworks to calculate the carbon intensity of hydrogen. ISO 14067 and ISO 14064 are also used in the European taxonomy[2] to calculate the life cycle GHG emissions savings for the manufacture of hydrogen. For TotalEnergies, these ISO frameworks have a general character on the calculation of the LCA with a lot of flexibility left to the stakeholder. Therefore, it will be important within the CHPS to give clear guidelines to developers so that LCA could be compared between different projects.

In addition, TotalEnergies considers that it would also be appropriate to take into account the following frameworks and accounting methods in support of the CHPS:

- many companies, including TotalEnergies, are using the GHG Protocol that establishes comprehensive global standardized frameworks to measure and manage GHG emissions from private and public sector operations, value chains and mitigation actions. Even if this initiative is private, it would be relevant to have a coherence between its methodology and the one that will be developed by DoE;

[2] Regulation (EU) 2020/852 of the European Parliament and of the Council by establishing the technical screening criteria for determining the conditions under which an economic activity qualifies as contributing substantially to climate change mitigation or climate change adaptation and for determining whether that economic activity causes no significant harm to any of the other environmental objectives.

- emissions from the construction, manufacture and decommissioning of capital equipment (including hydrogen plant, ...) should be excluded from the scope to ensure consistency with GHG reporting for other energy carriers/product;
- the Hydrogen Council initiated work this year to review the methodologies and guidelines for assessing the carbon footprint of hydrogen production pathways with the objective to develop a consensus based international industry recommendations. These recommendations should be used to develop an ISO standard methodology for GHG assessment of hydrogen.

b) What frameworks, analytic tools, or data sources can be used to quantify emissions and sequestration associated with biogenic resources in a way that is consistent with the lifecycle definition in the IRA?

No opinion.

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?

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)?

For TotalEnergies, it is first and foremost important to provide in the CHPS a clear definition of a by-product and a co-product.

In Europe, the following rules could be applied according to a draft regulation[3] released later this year by the European Commission:

- where the process allows to change the ratio of the co-products produced, the allocation shall be done based on physical causality by determining the effect on the process' emissions of incrementing the output of just one co-product whilst keeping the other outputs constant;
- where the ratio of the products is fixed and the co-products are all fuels, electricity or heat, the allocation shall be done by energy content. If allocation concerns exported heat on the basis of the energy content, only the useful part of the heat may be considered;
- where the ratio of the products is fixed and some co-products are materials not used for fuels, the allocation shall be done by the economic value of the co-products. The economic value considered shall be the average factory-gate value of the products over the last three years. If such data is not available, the value shall be estimated from commodity prices minus the cost of transport and storage.

The CertifHy project mentioned in the public consultation could also apply an economic value-based allocation (3-year average based on EuroStat price data).

[3] Commission delegated regulation on establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels.

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 TotalEnergies, it could be relevant that the GHG controls are carried out by an independent and impartial certifying body, which verifies that the procedures put in place by the hydrogen producer are accurate, reliable and fraud-proof and that the H2 mass balance management as well as the GHG calculation are compliant with the defined rules. These certifying bodies should be accredited by DoE. The GHG emissions certificates issued by the certifying bodies should be based on multi-year cycles: initial audit and annual follow-up.

b) 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?

In order to have clear and precise information about fugitive emission, midstream operators who operate the natural gas gathering systems from the wellheads and transmission networks to the hydrogen production sites will have an important role to play and must be fully integrated into the discussions.

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?

There are different ways to qualify electricity as renewable in order to produce renewable hydrogen. The current debate in Europe on the "Delegated Act" shows that it will be important to have simple and understandable rules to provide certainty to stakeholders.

For TotalEnergies, to qualify renewable electricity, the following options may be relevant:
- <u>direct connection between the renewable energy source and the electrolyzer:</u> in practice, this case can be limited depending on the space available at the co-located hydrogen consumer site;
- <u>location-based method</u>: the hydrogen produced may use the average share of electricity from renewable sources in the State of production if the electricity supplying the electrolyzer is coming from the grid;
- <u>market-based method:</u> an alternative for electricity coming from the grid is to use the emissions intensity embodied in contractual agreement between the electricity produced and the consumer:
    - hydrogen producer may use renewable electricity coming from a power purchase agreement (PPA) with a renewable electricity producer or through a green tariff program to qualify the production of hydrogen as renewable ensuring that the renewable properties of that electricity are claimed only once
    - hydrogen producer may use a book and claim mechanisms like the renewable energy certificates.

For market-based methods, TotalEnergies wants to emphasize that DoE should avoid to introduce too strict rules: (i) hydrogen producers should be able to use certificates or PPA with renewable sources already in service and have received public subsidies, (ii) if a criterion on the balancing between hydrogen production and electricity production is to be introduced, this one should be on a monthly basis because industrial consumers of hydrogen do not have the ability to quickly modulate their consumption, and (iii) if a criteria on the Balancing Authority is introduced, this one should be flexible to take into account the geography and the renewable energy potential of each State.

Furthermore, the scope of the installations that will have to comply with the previous criteria should be clarified in the CHPS: electrolyser alone or compression and auxiliaries as well.

Finally, SOEC electrolysers (solid oxide electrolyzer cell) use steam in order to produce hydrogen. It would be relevant for the DoE to indicate whether similar criteria could be applied to the origin of this steam.

d) What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0 kgCO2e/kgH2)?

No opinion.

Appendix / Data and Values for Carbon Intensity

Parameter	Assumptions made in analysis supporting proposed targets within draft CHPS	Respondent feedback		
		Regional or national average values achievable within next 5 years (i.e. by 2027)	Regional or national average values achievable in future years, and respective timescale	Rationale for estimates and any additional comments
Fugitive methane emissions	~1% of methane throughput between the point of natural gas drilling to the point of use is assumed to be released through fugitive emissions (e.g. during drilling process, transmission pipelines). This loss rate is estimated to reflect average fugitive methane emissions between natural gas plays across the U.S. and current steam methane reformers. The basis for this estimate is further described in GREET supporting documentation*:* https://greet.es.anl.gov/publication-update_ng_2021 In columns C-E, please provide feedback on the technical and economic feasiblity of this leak rate being accessible regionally or as a national average.	To date, at national level, it is assumed that the 1% fugitive emissions is achievable.	Further reduction of 50% is targeted by 2030.	Leak detection is monitored on assets through the Leak Detection and Repair (LDAR) methodology, via the use of optic camera to identify fugitive emissions.

Rate of carbon capture	~95% carbon capture at natural gas reforming facilities and gasification plants is assumed to be commercially deployable, and to enable one path to achieving the targets proposed in this draft guidance. In columns C-E, please provide feedback on the technical and economic feasiblity of this rate of carbon capture being deployed.	95% CO2 capture is achievable for SMR or gasification process. In general, Syngas (process gas ex reforming / shift section) is treated by amine or cryogenic process to separate CO2 (High pressure Pre capture). If natural gas (or carbonated fuel gas) is used for prereforming or reforming heater or auxiliary boilers, flue gas need to be treated by amine to recover remaining CO2 (post combustion capture).		
Share of clean energy within electricity consumption	Use of predominantly clean energy (i.e. >85% clean energy, < 15% U.S. grid mix) in electrolysis is expected to enable achievement of the lifecycle target proposed in this draft guidance. In columns C-E, please provide feedback on the technical and economic feasibility of electrolyzers accessing this share of clean energy.	Technically, electrolysers can accept any type of electricity, the main constraint is related to the intermittency of the supply. Should the clean energy supply be intermittent, additional costs occur, impacting the cost of Hydrogen by up to 0.5 to 1$/kgH2.		Split between clean energy and US grid mix is based on the capacity to develop clean energy (renewable plants) in US along with the access to additional clean energy to increase the electrolysis load factor.

CO2 leak rate from CCS	Leak rates of <1% from CO2 sequestration sites are assumed to be feasible today, and expected to enable achievement of the proposed targets in this draft guidance. In columns C-E, please provide feedback on the technical and economic feasiblity of this CO2 leak rate being achieved.			
Other (e.g. pressure and purity conditions at output of hydrogen production facilities)	In analysis to inform the CHPS, systems were modeled to achieve hydrogen production with 99% purity and 3 MPa at the outlet.	Hydrogen purity will depend on technology used and presence of a Purification system. Targeted purity: 99.7% to cover different usage (mobility, industry). Lower purity is acceptable for industrial processes (for example refineries) Targeted pressure: Between 1 bar and 80 bars	Same	