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U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

RE: Comments Responding to the U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance – Fidelis New Energy, LLC

Fidelis New Energy, LLC ("Fidelis") appreciates the opportunity to respond to the U.S. Department of Energy's ("DOE") Clean Hydrogen Production Standard ("CHPS") Draft Guidance. Fidelis is an energy transition company driving decarbonization through investments in renewable fuels, low-carbon intensity products, and carbon capture and storage. Using proprietary technology, Fidelis aims to develop, invest, and deliver climate positive and carbon negative infrastructure to reach carbon reduction and climate positive targets. Fidelis is headquartered in Houston, Texas with projects in Louisiana.

Fidelis applauds the Administration's and DOE's commitment to supporting U.S. energy development, securing U.S. energy independence, and tackling the climate crisis. The $62 billion appropriated to the DOE under the Infrastructure Investment and Jobs Act of 2021, also known as the Bipartisan Infrastructure Law ("BIL"), in combination with the energy tax incentives and $369 billion allocated for "Energy Security and Climate Change" under the Inflation Reduction Act ("IRA"), will drive significant U.S. job creation and industry growth while simultaneously supporting climate goals and providing equitable outcomes for disadvantaged communities.

Fidelis particularly commends the $7 billion Regional Clean Hydrogen Hubs ("H2Hubs") Program established by the BIL. Hydrogen energy development has the potential to fundamentally reshape clean energy generation, storage, and transport, and it is critical that the U.S. establish itself as a leader in this burgeoning industry. Fidelis agrees that the implementation of H2Hubs Program, in concert with other federal support like the IRA 45V Tax Credit, will catalyze U.S. production, processing, delivery, storage, and end-use of clean hydrogen, "in support of the Biden Administration's goal to achieve a carbon-free electric grid by 2035 and a net zero emissions economy by 2050."

As an industry stakeholder, Fidelis offers the below feedback to support the Administration in its efforts to galvanize domestic hydrogen development. The establishment of a uniform CHPS that facilitates both the H2Hubs Program and broader federal hydrogen development initiatives will provide the foundational consistency and clarity necessary to support comprehensive hydrogen development across the country.

Fidelis Stakeholder Feedback

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

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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.

Response: See below (also provided in the attached spreadsheet) –

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 feasibility of this leak rate being accessible regionally or as a national average.	It is technically and economically feasible to achieve <1% fugitive methane emissions today, as seen by voluntary methane emission reductions undertaken through groups like One Future, MiQ certification, and Project Canary. Members of One Future achieved a 0.334% methane intensity in 2019 for the entire upstream value chain from Production through to distribution as seen by the 2020 Methane Intensity Report. In addition to these voluntary programs, Methane Emissions Reduction Program (H.R 5376 Sec. 60113) strongly incentivizes significant reduction in methane emissions to below <1% for the entire value change with fees for noncompliance with methane emissions limits for each segment beginning in 2024 with $900 per metric ton of methane above the allowable threshold and increasing to $1,500 per metric ton by 2026 and there on forward. This program applies to 94% of total U.S. onshore production, 67% of total U.S. processing facilities, 27% of transmission compressor stations, and 49% of total U.S. transmission pipeline mileage. If assuming the maximum limit leakage rate in the Methane Reduction Program for each segment of onshore natural gas, the resultant methane emission would be 0.52% (presupposing that all segments fall under the definition of applicability for the regulation).	Regional and national values of methane emissions should continue to decrease as compliance with the Methane Emissions Reduction Program continues and facilities not explicitly covered by the program adopt the limits outlined in the program. Additionally, it seems likely that facilities will reduce emissions beyond the thresholds of the Methane Emissions Reduction Program with more stringent certifications through MiQ or similar.	As evidenced by One Future, methane emissions rates are available for individual systems and segments of the natural gas value chain. Use of system specific low methane natural gas should be allowed in order to calculate site specific hydrogen carbon intensity.
Rate of carbon capture	~95% carbon capture at natural gas reforming facilities and gasification plants	It is conceptually possible to retrofit existing natural gas reforming facilities to achieve >90% carbon capture by adding post combustion capture. However, due to likely plot constraints around existing	Greenfield developments will continue to be able to achieve >95% capture, which	Definition of carbon capture for hydrogen production should be based on a time averaged % recovery of the carbon in the natural feed and/or fuel.

	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 feasibility of this rate of carbon capture being deployed.	reformers and cost it is likely unfeasible to implement post combustion capture in practice. Syngas capture on existing plants is more likely to be feasible in practice due to the higher-pressure capture allowing for minimal plot space, cost, and energy requirements. Syngas capture would allow for upwards of ~60% or higher carbon recovery for most SMR designs. New greenfield developed hydrogen plants can reach and exceed 95% capture through proper technology selection on hydrogen production and carbon capture based on proven technology offerings today.	will likely be able to climb higher as new configurations are deployed. Retrofitting existing SMRs will continue to struggle to meet high capture rates.	C(recovered) / C in Feed+ Fuel to Hydrogen unit. Additionally, life cycle analysis of particular projects should be based on site specific carbon recovery rates, which can exceed 95%.
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 electrolyzes accessing this share of clean energy.	Achieving the approximately 85% clean energy and 15% U.S. grid mix ratio would require the facility to be co-located with a renewable generation asset or some form of non-direct connected ("book and claim") renewable energy for the foreseeable future given that renewable electricity generation in the first half of 2022, as reported by the Energy Information Administration, only accounted for 24% of electricity. As expanded upon in our later response to 3)c), "book and claim" renewable generation should not be allowed for under the Clean Hydrogen Production Standard due to significant issues like grid instability induced by intermittent renewable generation with mismatched demand and constrained transmission lines. Any imported grid connected electricity should be subject to local grid emission factors. Only "behind the meter" renewable generation or direct connection to renewable generation should not incur the local grid electricity emission factor for that electricity. Additionally, electrical consumption for electrolysis must also include balance of plant utilities and electrical loads to quantify carbon intensity. Underlying assumptions about electrolyzer efficiency must factor these auxiliary loads, including water preparation, when considering renewable energy supply.		The Clean Hydrogen Production Standard should only allow consideration of electric power with a carbon intensity lower than the local grid for direct connect generation. Remote low carbon generation, through practices like book and claim, creates grid instability risk due to transmission line constraints, generation intermittency, and mismatches of local electricity generation and demand.
CO_2 leak rate from CCS	Leak rates of <1% from CO_2 sequestration sites are assumed to be feasible today and expected to enable achievement of the proposed targets in	Negligible leakage rates are achievable from CO_2 sequestration sites today with little economic impact due to stringent Class VI Carbon Capture, Utilization, and Storage ("CCUS") permitting requirements.	Negligible leakage rates will continue to be possible from sequestration sites.	Stringent metering requirements in programs like the IRA's 45Q Tax Credit or the California Air Resources Board's ("CARB") Carbon, Capture, Sequestration protocol, and the related program incentives per metric ton of CO_2, strongly incentivize the

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	this draft guidance. In columns C-E, please provide feedback on the technical and economic feasibility of this CO2 leak rate being achieved.			minimization of any leakage to the maximum extent in compression, transmission and sequestration. Additionally, permitting for a Class VI well (CO2 Sequestration well) is extremely stringent and rigorous to ensure the containment and permeance of the sequestered CO2. The Class VI well permitting requires compliance with the following: 1. Proper characterization of confining intervals within the injection formation; 2. Proper evaluation of any artificial penetrations within the carbon dioxide plume and artificial penetration front that form the Area of Review ("AoR"); 3. necessary 3D baseline seismic evaluation of AoR before injection is approved; 4. 3D seismic surveys conducted within the AoR to monitor the plume extent during the operational period of the injection well; 5. Proper understanding of the saturation rates of Carbon Dioxide within the injection formation; 6. Use of both pressure/temperature transducers and distributed temperature sensing via fiber optics for direct monitoring of the pressure front within the injection zone; 7. Time-lapse vertical 3D seismic profiles ("VSPs") used to monitor carbon dioxide plume movement and development; 8. Use of distributed acoustic sensing ("DAS") technology for passive seismic monitoring; and 9. Robust operational plan to respond to and act accordingly to any abnormalities identified during the operational period.
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.	99% purity hydrogen at 3 MPA is readily achievable today through a number of production pathways.		This is a reasonable boundary condition for hydrogen to form the functional unit for carbon intensity analysis. As stated in the CHPS guidance, hydrogen exported at a higher pressure should be credited for the energy (and emissions) to produce higher pressure hydrogen.

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

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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?

Response: Regional developments can have similar emission factors for key carbon intensity parameters like local grid carbon intensity. However, it is also possible for notable differences to occur in the carbon intensity for parameters like natural gas that could have significant differences in methane leakage rates.

GREET default estimates should serve as the basis for many carbon intensity parameters, with the ability to substitute development specific carbon intensity parameters, such as natural gas methane leakage and natural gas transmission distance which GREET has the existing functionality to model.

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.

Response: While not a direct emission source, Figure 1 and the demonstrated lifecycle boundary ignore the use of water as part of the production of hydrogen. Water sources and consumption should be tracked and quantified as part of the lifecycle analysis to better understand the broader impacts of hydrogen production facilities on the environment beyond just CO2 emissions.

While commonly understood that lifecycle emissions can be allocated between co-products figure 1 does not explicitly show co-products and the allocation of emissions. Figure 1 should be updated to note that co-product allocation is allowed for under the clean hydrogen production standard.

d) Mitigating emissions downstream of the site of hydrogen production will require close monitoring of potential CO2 leakage. 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?

Response: The strenuous permitting requirements of a Class VI CCUS well and Department of Transportation requirements for CO2 pipelines in the U.S. ensure extremely high levels of containment integrity for transportation and sequestration of CO2 when sent to geological sequestration.

On a technical basis, leak detection of carbon dioxide from pipelines via a statistical volume balance method model is an accepted method in the transmission of natural gas. The system is a software solution that uses both flow and pressure data from Supervisory Control and Data Acquisition, Distributed Control Systems, Programmable Logic Controller or Remote

Telemetry Unit systems. A statistical volume balance software solution can detect leaks under all operating conditions with no change in minimum detectable leak size during transient periods. The detection system can detect both onset and existing leaks and quickly shut-down a pipeline in the event of a leak or rupture. The statistical volume software solution can detect leaks from the input of carbon dioxide into the pipeline all the way to the wellhead.

Leaks within the carbon dioxide plume area, although very rare, can be detected through the well-established process of direct pressure-front monitoring using both pressure/temperature transducers and distributed temperature sensing via fiber optics for direct monitoring of the pressure front within the injection zone.

In addition to the aforementioned monitoring methods, additional technologies and methods can be used to supplement and support the direct pressure front monitoring to allow for indirect geophysical monitoring of the plume and pressure front. These technologies and methods include 3D seismic surveys which can be conducted within the Area of Review of the carbon dioxide plume during the operational period. Time-lapse 3D vertical seismic profiles can also be used to monitor the plume movement and development indirectly. VSPs use distributed acoustic sensing technology and offer higher resolution images of the subsurface than surface seismic.

There is minimal incremental cost related to conducting detailed monitoring of CO2 emissions from sequestration wells as such investments are already a required under the permitting requirements of the Class VI CCUS, which requires leak detection, plume front characterization, and operational plans for real time monitoring.

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?

Response: As captured in Figure 1 of the Clean Hydrogen Production Standard, site specific fugitive, process, and combustion emissions from hydrogen production and CO2 capture should be rigorously monitored and reported, capturing both typical GHG emissions and hydrogen emissions as the scientific community continues to understand the indirect effects of hydrogen.

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

Response: Systems that utilize CO2 generated in the conversion of fossil fuels to hydrogen in synthetic fuels should consider the full system boundary from fossil fuel extraction through synthetic fuel combustion with consideration for the total energy output of the system and potential co-product allocation between the synthetic fuel useful energy output and fossil fuel useful energy outputs.

Atmospheric originated CO2 should be considered neutral for both direct air capture and biogenic CO2 by including the appropriate biogenic uptake factor.

The CO2 captured during the production of hydrogen and used for applications that result in the CO2 effectively being stored from the atmosphere for extend periods of times, such as the production of concrete, should be treated as sequestered with a permanence factor. The permanence factor should quantify how much CO2 leaks from the material or use into the atmosphere to pro-rate the effectiveness of storing the CO2 in that medium.

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?

Response: The ISO frameworks identified in the IPHE HPTF Working Paper for LCA form a beneficial framework for a uniform methodology for conducting the life cycle analysis.

The inclusion of Scope 1, Scope 2 and partial Scope 3 emissions as recommend by in the IPHE HPTF Working paper form a system boundary is equivalent to system boundary as is recommend by Figure 1 of the Clean Hydrogen Production Standard (“CHPS”). A drawback of the Scope 1, Scope 2, and Scope 3 framework is that the framework is unclear on accounting biogenic carbon emissions. It is our recommendation that the lifecycle emissions should be determined based on the system boundary as described in Figure 1 of CHPS utilizing the GREET model to ensure uniform emission calculations as opposed to the Scope 1, Scope 2 and Scope 3 framework.

   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 CO2 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?

Response: No response at this time.

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?

Response: GHG emissions should be allocated on a process system level basis. Examples of this are feedstock extraction emissions should be allocated between the various co-products generated in the extraction process; likewise, emissions from the hydrogen production including the embodied upstream emissions should be allocated to the co-products of the hydrogen production step. This is consistent with established methodologies as seen in the IPHE HPTF Working paper.

System expansion is an appropriate method of allocating GHG emissions to co-products in the hydrogen production step. As described in the IPHE HPTF Working Paper, system expansion allows the subtraction of environmental burdens associated with substitute produces from the hydrogen production system under study. This allows for the valorization of energy and non-energy products (oxygen, elemental carbon) alike. Care should be taken for comparing substitute products at equivalent conditions. For example, oxygen produced as by product of electrolysis should be compared oxygen production processes at equivalent conditions: purity, temperature, pressure.

Energy-based approach is also appropriate for allocation of systems that valorizes energy products (steam or electricity).

Mass based co-product allocation is an inappropriate allocation method for hydrogen production pathways due to the low molecular weight of Hydrogen, which results in disproportionate allocation of emissions to the co-product. For example, a mass-based approach for electrolysis-based Hydrogen production would result in approximately 89% of the lifecycle emissions being allocated to the co-produced oxygen.

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)?

Response: Hydrogen rich off gas streams generated in refineries or other industrial processes are typically used for onsite power and heat generation or recovered for use

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in processes such as hydrogenation. Substitution method as outlined in the IPHE HPTF Working is an appropriate method as the majority of this produced Hydrogen is used for power and heating today and this heat will have to be produced using other energy sources.

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?

Response: GHG emissions of commercial-scale deployments can be verified through metered connections of material and energy inflows and outflows. Verification of commercial facilities lifecycle emissions through the metering of material inputs and out connections is a well-established practice today for clean fuels facilities participating in California's Low Carbon Fuel Standard and other markets. Rigorous metering and reporting of energy and material inputs and outputs allow for the site-specific carbon intensity and GHG emissions to be readily tracked and calculated.

   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?

Response: Commercial natural gas consumers can work with their natural gas provider to understand the mix of natural gas being supplied to their facility and from where it is being transported.

There is a growing industry consensus on efforts to minimize fugitive emission rates for specific natural gas providers in upstream production steps. This is seen by groups and organizations like Project Canary, One Future, MiQ, and others working to limit and certify methane emission rates. As these efforts continue to grow along with regulatory incentives/mandates established by the Methane Emission Reduction Program, it is likely that more and more natural gas supply will have system specific fugitive emissions.

DOE should consider and allow for the use of system specific fugitive emissions with applicable certification and or monitoring rigor when quantifying the life cycle of hydrogen production.

   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?

Response: Hydrogen production in the United States is primed to grow significantly given both the Clean Hydrogen Production Standard and Clean Hydrogen Production Tax Credit (§45V). Increased power consumption due to production of electrolytic hydrogen could significantly exacerbate grid instability if "book and claim" market mechanisms for determination of the electricity emissions for Hydrogen Production encourage the use of remote renewable or low carbon generation for electrolytic hydrogen plants. Therefore, "book and claim" market structures like renewable energy credits ("RECs") and power purchase agreement ("PPA") should not be allowed in characterizing the intensity of electricity emissions for hydrogen production.

"Book and claim" market structures would allow electrolytic hydrogen producers consuming grid power at constant rates geographically segregated from the renewable generation units to claim non-local grid emission factors. The geographic distance between renewable generation and hydrogen production unit as well as the constant power demand of the clean hydrogen production unit enabled by "book and claim" ignores the reality that solar and wind generation is intermittent and transmission of the produced electricity is typically locationally constrained due to congested transmission lines. This results in decreased grid stability and reliability. Thus, to meet the increased demand of these additional electrolytic hydrogen producers and maintain stability, grid operators are required to add additional fossil fuel generation, grid battery storage, and add transmission lines to move renewable and/or low carbon power from the generation source to the "book and claim" hydrogen producer. However, the cost of these system enhancements and maintenance are transferred to the other users of the transmission grid without providing any mechanism for compensation, causing market distortions not paid for by those that create the issues.

These effects are magnified as intermittent wind and solar generation have become major power sources in many areas. For example, April 2022, the Energy Reliability Council of Texas ("ERCOT") grid hit a record wind penetration of 69.5% and California hit 100% renewable penetration[1,2].

These drawbacks of "book and claim" generation are evidenced by California's famed "Duck Curve" and by Locational Marginal Pricing which causes electricity rates to go negative at peak renewable generation to discourage over generation in certain grid nodes while electricity rates are very high in high usage areas. Allowing "book and claim" for

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[1] ERCOT, (November 2022). https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf
[2] Lewis, M. (May 2, 2022). https://electrek.co/2022/05/02/california-runs-on-100-clean-energy-for-the-first-time-with-solar-dominating/

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clean H2 production would only increase these pricing discrepancies without addressing the real infrastructure gaps.

Allowing for "Book and Claim" renewable electricity in characterizing the intensity of electricity emissions for hydrolytic hydrogen production ignores the negative impacts on the transmission grid stability and reliability; the significant investments required for new transmission lines, utility energy storage facilities, and dispatchable fossil-based generation units; and the Locational Marginal Pricing impacts of, in effect subsidizing electrolytic hydrogen production via grid power. While subsidizing electrolysis hydrogen, the "book and claim" also exacerbates overgeneration from too much wind and solar power requiring curtailments in areas that have "too much" renewable generation resulting in worse economics for wind and solar producers due to the lower pricing and curtailments.

Hence, "book and claim" for electrolysis-based hydrogen production will cause huge market distortions as it will not replace the need for transmitting power from the production site to the hydrogen production site and instead will transfer such costs to other users of the transmission grid without providing any mechanisms for compensation.

Electrical power "book and claim" mechanism results in higher usage of fossil fuels for power generation, higher costs for other customers, lack of funding for battery storage facilities for load balancing, lack of funding for new transmission lines moving renewable generation from remote locations to industrial areas producing and using renewable generation through "book and claim" virtual transmission ignoring the reality of moving large amounts of intermittent power, negatively impacts on transmission grid stability and reliability, and causing higher overall grid carbon intensity

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

Response: No response at this time.

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

Response: No response at this time.

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Thank you for the opportunity to submit these comments. We welcome the opportunity to meet with the Department of Energy discuss these issues in greater detail and to answer any questions that you may have.

Respectfully submitted,

Fidelis New Energy, LLC

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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.	It is conceptually possible to retrofit existing natural gas reforming facilities to achieve >90% carbon capture by adding post combustion capture. However, due to likely plot constraints around existing reformers and cost it is likely unfeasible to implement post combustion capture in practice. Syngas capture on existing plants is more likely to be feasible in practice due to the higher-pressure capture allowing for minimal plot space, cost, and energy requirements. Syngas capture would allow for upwards of ~60% or higher carbon recovery for most SMR designs. New greenfield developed hydrogen plants can reach and exceed 95% capture through proper technology selection on hydrogen production and carbon capture based on proven technology offerings today.	Greenfield developments will continue to be able to achieve >95% capture, which will likely be able to climb higher as new configurations are deployed. Retrofitting existing SMRs will continue to struggle to meet high capture rates.	Definition of carbon capture for hydrogen production should be based on a time averaged % recovery of the carbon in the natural feed and/or fuel. C(recovered) / C in Feed+ Fuel to Hydrogen unit. Additionally, life cycle analysis of particular projects should be based on site specific carbon recovery rates, which can exceed 95%.
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 techincal and economic feasibility of electrolyzers accessing this share of clean energy.	Achieving the approximately 85% clean energy and 15% U.S. grid mix ratio would require the facility to be co-located with a renewable generation asset or some form of non-direct connected ("book and claim") renewable energy for the foreseeable future given that renewable electricity generation in the first half of 2022, as reported by the Energy Information Administration, only accounted for 24% of electricity. As expanded upon in our later response to 3)c), "book and claim" renewable generation should not be allowed for under the Clean Hydrogen Production Standard due to significant issues like grid instability induced by intermittent renewable generation with mismatched demand and constrained transmission lines. Any imported grid connected electricity should be subject to local grid emission factors. Only "behind the meter" renewable generation or direct connection to renewable generation should not incur the local grid electricity emission factor for that electricity. Additionally, electrical consumption for electrolysis must also include balance of plant utilities and electrical loads to quantify carbon intensity. Underlying assumptions about electrolyzer efficiency must factor these auxiliary loads, including water preparation, when considering renewable energy supply.		The Clean Hydrogen Production Standard should only allow consideration of electric power with a carbon intensity lower than the local grid for direct connect generation. Remote low carbon generation, through practices like book and claim, creates grid instability risk due to transmission line constraints, generation intermittency, and mismatches of local electricity generation and demand.

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.	Negligible leakage rates are achievable from CO2 sequestration sites today with little economic impact due to stringent Class VI Carbon Capture, Utilization, and Storage ("CCUS") permitting requirements.	Negligible leakage rates will continue to be possible from sequestration sites.	Stringent metering requirements in programs like the IRA's 45Q Tax Credit or the California Air Resources Board's ("CARB") Carbon, Capture, Sequestration protocol, and the related program incentives per metric ton of CO2, strongly incentivize the minimization of any leakage to the maximum extent in compression, transmission and sequestration. Additionally, permitting for a Class VI well (CO2 Sequestration well) is extremely stringent and rigorous to ensure the containment and permeance of the sequestered CO2. The Class VI well permitting requires compliance with the following: 1. Proper characterization of confining intervals within the injection formation; 2. Proper evaluation of any artificial penetrations within the carbon dioxide plume and artificial penetration front that form the Area of Review ("AoR"); 3. necessary 3D baseline seismic evaluation of AoR before injection is approved; 4. 3D seismic surveys conducted within the AoR to monitor the plume extent during the operational period of the injection well; 5. Proper understanding of the saturation rates of Carbon Dioxide within the injection formation; 6. Use of both pressure/temperature transducers and distributed temperature sensing via fiber optics for direct monitoring of the pressure front within the injection zone; 7. Time-lapse vertical 3D seismic profiles ("VSPs") used to monitor carbon dioxide plume movement and development; 8. Use of distributed acoustic sensing ("DAS") technology for passive seismic monitoring; and 9. Robust operational plan to respond to and act accordingly to any abnormalities identified during the operational period.
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.	99% purity hydrogen at 3 MPA is readily achievable today through a number of production pathways.		This is a reasonable boundary condition for hydrogen to form the functional unit for carbon intensity analysis. As stated in the CHPS guidance, hydrogen exported at a higher pressure should be credited for the energy (and emissions) to produce higher pressure hydrogen.