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February 26, 2024

Internal Revenue Service
P.O. Box 7604, Ben Franklin Station
Washington, D.C. 20044

The Honorable Lily L. Batchelder
Assistant Secretary for Tax Policy
Department of the Treasury
1500 Pennsylvania Avenue, N.W.
Washington, D.C. 20220

Mr. William M. Paul
Principal Deputy Chief Counsel and Deputy Chief
Counsel (Technical)
Internal Revenue Service
1111 Constitution Ave., NW
Washington, D.C. 20224

IRA 45V – New Fortress Energy's Comments and Proposal from a Clean Hydrogen Perspective

Dear Mrs. Batchelder and Mr. Paul,

On behalf of New Fortress Energy Inc. ("NFE") and its wholly owned subsidiary, ZeroParks Inc. ("Zero"), we are grateful for the opportunity to provide feedback and recommendations to the Biden Administration, Treasury, and the IRS on the §45V Credit for Production of Clean Hydrogen ("45V") pursuant to the Notice of Proposed Rulemaking (REG-117631-23), hereby referred to as the "Draft Rules". The subjects of clean hydrogen, the energy required to produce it, and the general success of the U.S. clean hydrogen economy, are topics we take extremely seriously. We hold the utmost respect and appreciation for the leadership the Biden Administration has demonstrated in energy transition, decarbonization, and combatting climate change, and we believe the U.S. clean hydrogen market can be a world leader in helping to achieve these goals. We appreciate the opportunity to comment on the Draft Rules and, given NFE's core mission to provide cleaner and cheaper power to address energy inequality around the world, we believe we are in a unique and experienced position to assist in this process.

As a general comment, we believe the Draft Rules, as written, will significantly limit clean hydrogen adoption in the U.S., delay the Biden Administration's decarbonization efforts, and eliminate the potential for millions of jobs that the clean hydrogen market could generate. Additionally, as outlined in this letter and the accompanying Articles, the current Draft Rules will cause disparity between geographies in the U.S., limiting which regions can support clean hydrogen projects and restricting broad market adoption. In this letter of comment, we not only outline why we hold this view, but also offer suggested changes, based on our experience in the clean hydrogen and energy transition space, that we believe would yield positive results for both the Biden Administration's decarbonization goals and the clean hydrogen market more generally. At all times we strive to uphold the intent of the Inflation Reduction Act ("IRA") of 2022[1] while detailing areas of

[1] https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf

common ground where we believe the Biden Administration can modify the Draft Rules in a manner that will enable the U.S. clean hydrogen economy to flourish, while preserving the integrity of the renewable energy that is essential to its growth.

Background to New Fortress Energy

NFE was established approximately ten years ago, born out of the first-of-its-kind conversion (from diesel to cleaner burning natural gas) of the locomotives operating on the Florida East Coast Railway. Since then, it has grown into a global organization, with a current enterprise value of approximately $13bn, that focuses on energy transition through the execution of energy and infrastructure projects around the world. At its core, NFE is an energy transition company with its chief mission to provide access to cleaner power for energy impoverished parts of the world. NFE solves energy inequality by developing the supply chain necessary to convert customers from heavily polluting energy sources to cleaner burning, cheaper natural gas. It currently owns, operates, or is developing assets in more than 10 countries, consisting of liquified natural gas ("LNG") storage, liquefaction and regasification terminals, and thermal power generation plants. Most recently, NFE took over the management and operation of Puerto Rico's entire power generation system. In this capacity it has improved power generation reliability in existing assets, deployed critical temporary power generation infrastructure with the support of FEMA, is working to convert many of the island's power sources from diesel to natural gas, and to lower power prices for the island's inhabitants.

ZeroParks – Our Clean Hydrogen Business

Zero, established in 2020 as a pure-play, clean hydrogen production company, is a continuation of NFE's energy transition focus. Zero adopts the same customer centric approach for the development of clean hydrogen production hubs in key regions throughout the U.S. which have access to low-cost renewable power, an established network of logistics infrastructure, and proximity to industrial hydrogen demand. Zero's goal is to provide its customers with an easy and seamless transition from grey hydrogen, produced by a high carbon intensity process, to green (or clean) hydrogen, produced via electrolysis using renewable energy. Zero is a leader in the U.S. clean hydrogen movement, with its project in Beaumont, Texas ("ZeroPark I"), being one of the first industrial scale projects in the United States to reach Final Investment Decision ("FID") and begin construction.

ZeroPark I will build up to 200 MW of electrolysis, constructed and installed in two distinct phases of 100 MW each, the first of which is expected to be operational in early 2025. Zero will utilize Proton Exchange Membrane ("PEM") electrolysis technology manufactured and supplied by Electric Hydrogen ("EH2"), a U.S. based hydrogen technology start-up enterprise. The hydrogen produced from ZeroPark I will be supplied to OCI Global's ammonia and green methanol plant in Beaumont under one of America's first, arm's length green hydrogen supply agreements in the IRA era. The Beaumont site is a key region for Zero, given the existing industrial (grey) hydrogen demand in the region, including the two largest refineries in the U.S. (Exxon Beaumont and Motiva Port Arthur), and the existing infrastructure needed to support industrial decarbonization (i.e. pipeline access, transmission level power distribution, and ample industrial land). Zero has additional projects in development around the U.S. including in the Northeast and Pacific Northwest where it will source clean power largely from nuclear and hydroelectric generation assets, respectively. The breadth of energy sources that will supply Zero's clean hydrogen projects means the implementation of the IRA 45V production tax credit for clean hydrogen is fundamental to Zero's ability to provide its customers with cost effective green hydrogen as a replacement for carbon-emitting grey hydrogen and to support emerging clean hydrogen markets.

The Three Pillars

This letter focuses on the specific requirements applied to the energy sources used to produce clean hydrogen via the electrolysis of water to qualify for IRA 45V production tax credits. The term “clean hydrogen” as used in this letter, and accompanying Articles, means hydrogen produced via electrolysis which meets the carbon intensity threshold of 0 - 0.45 kg CO2e per kg of hydrogen. The three fundamental considerations (or “Three Pillars”) in connection with the use of renewable energy (via Energy Attribute Certificates or “EACs”) to produce clean hydrogen, as detailed in the Draft Rules are: (i) time matching, (ii) incrementality, and (iii) deliverability. As previously stated, unless modified, we believe the Draft Rules will hinder the U.S. clean hydrogen economy, delay energy transition efforts, and restrict broad market adoption of clean hydrogen. This would be counter to the intention of §45V under the IRA and further exacerbate the climate crisis whilst limiting the U.S.’s role in the global energy transition. However, we believe the changes proposed in this letter and detailed in the accompanying Articles would enable the U.S. clean hydrogen economy to flourish, capture the intent of the IRA, generate thousands of U.S. clean technology jobs, and address environmental concerns. A summary of our proposed changes are as follows:

I. **Time Matching** – we propose that clean hydrogen facilities which start construction before January 1, 2028, should be grandfathered over the full 10 year 45V term and be allowed annual matching for five (5) years, once the facility reaches Commercial Operations Date (“COD”), then transition to quarterly matching beginning in year six (6) and ending in year ten (10). Additionally, for those early projects which begin construction before January 1, 2028, we propose a standard four year safe harboring mechanism. For qualifying clean hydrogen facilities which begin construction after January 1, 2028, we suggest time matching on an hourly basis should be phased in gradually, with annual matching to apply until 2030, monthly matching to apply from 2030 to 2035, and hourly matching to apply after 2035. A gradual progression to strict hourly matching will reduce the disparity that exists today between different regions in the U.S. due to resource and development limitations for renewable energy. A gradual progression also means regions which currently lack sufficient EAC sources, which are needed to offer hourly matching, will have sufficient time to develop the renewable mix to achieve levels. A grandfathering provision will enable early clean hydrogen projects to succeed by giving developers more flexibility in sourcing EACs and will eliminate the need for an initial burdensome plant design (i.e. adding battery storage, oversizing the electrolyzer for intermittency, adding hydrogen storage, switching renewable energy sources after operation has commenced, etc.) that can run in an hourly matched manner or for the facility to change its EAC sourcing after it becomes operational. Adding strict hourly matching without adequate time for both the EAC and clean hydrogen markets to develop, will drive the cost of clean hydrogen up to a level that will prevent grey hydrogen displacement and restrict clean hydrogen market adoption. The buildout of clean hydrogen projects (and 45V credits), while maintaining a well-defined target date for strict time matching, will, in turn, promote the further build out in all regions of a proper mix of renewables needed for strict hourly matching. Further details are provided in Article I.

II. **Incrementality** – we propose that qualifying clean hydrogen facilities which begin construction before January 1, 2028, with a four year safe harbor, or commence commercial operations (“COD”) prior to January 1, 2030, should be exempt from the requirement to source EACs which meet the incrementality requirement for the duration of the IRA 45V term (or ten years). Grandfathering on incrementality would provide flexibility in sourcing the necessary EACs for early clean hydrogen projects and give ample time for regions with fewer EAC assets to catch up (see Figure 1 in Section I(B)(2)), thus leveling the playing field between all geographies in the U.S. Grandfathering will also provide a marked transition to stricter incrementality requirements, and would encourage the development of early clean hydrogen projects in regions with limited EAC assets that may not otherwise be built given the lack of qualifying EAC generating resources in those regions. Incrementality rules should also allow options for Minimal Emitting Generators ("MEGs") to participate in the new clean hydrogen economy. Specifically, MEGs should not be required to meet incrementality requirements if certain thresholds are met (like controls around induced grid emission from MEGs shifting load, and regional safeguards requiring new generation to be MEG) and there should be a minimum specified level of a MEG's generation capacity that is permitted to support a new clean hydrogen load. On this point, we note that three of the seven proposed DOE Hydrogen Hub projects selected for funding by the DOE pursuant to the Infrastructure, Investment and Jobs Act of 2021, will produce clean hydrogen using energy (nuclear and hydroelectric) from MEGs. We believe closer alignment is required between the Draft Rules and the steps taken by the DOE to support the nascent clean hydrogen economy. Further details are provided in Article II.

III. **Deliverability** – we believe this concept should be modified to allow clean hydrogen producers to source (and EAC generators to provide) EACs from adjacent and interconnected Balancing Authorities, rather than requiring generators and producers to be located within the same authority. This flexibility will eliminate geographic differences which, in the early stages of the IRA era, would otherwise put certain regions at a disadvantage if they lack either adequate existing renewable resources or sufficient hydrogen demand. It will also encourage the further buildout of new renewable generators in all regions and limit incremental regional grid emissions since interconnection and proximity (being located adjacent to an authority) will be a requirement. Further details are provided in Article III.

IV. **Other notable Items that we would propose include**:

(i) **45H2V- GREET Consistency** - Provisions should be added to ensure that updates to the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation ("GREET") model specific to the IRA 45V, 45H2V-GREET (or "GREET model"), do not impact a clean hydrogen facility's Carbon Intensity ("CI") score (assuming no changes have been made in the facility's process inputs). As an example, if a clean hydrogen facility qualifies for a certain level of 45V credit based on one version of the GREET model, as such its level of 45V credit changes due to an update in the GREET model, it would have a detrimental effect on that facility's ability to secure funding due to the uncertainty in 45V credit value and resulting project economics, which the facility cannot reasonably control.

(ii) **EAC Registry Standards** - A national standard should be established for EAC tracking and qualification, including requirements for EAC minting frequency. The current Draft Rules address this need in part but do not include any guidance on EAC minting frequency. There is typically a delay of up to two months for some EAC registries between the generation of an EAC and its minting (or when it becomes usable and tradeable). Such a delay will lead to difficulty in matching EACs by the hour and will undoubtedly result in instances where clean hydrogen is produced under an assumption such that production has matched EACs being generated when, in fact, a producer has inadequate EACs to retire or cannot source EACs necessary to cover all their production.

(iii) **45H2V-GREET Grid Boundaries -** The GREET model should use the grid emission profile to match the DOE's Balancing Authority map, thereby providing a better representation of actual grid emission profiles and the resulting CI scoring; and

(iv) **Clean Hydrogen Operating Margin** – The Draft Rules should add a provision for operational tolerance, whereby a clean hydrogen producer has a maximum percentage, or buffer, to operate outside its corresponding EAC profile that would not be penalized by an aggregate CI score (based on the combined production from EAC-matched and grid-supplied product as dictated in the current Draft Rules). Rather, the clean hydrogen producer would just forgo 45V credit for volumes it produces that do not have corresponding EACs, up to a maximum of twenty percent (20%) of total annual volume.

Regarding proposals (4)(ii) and (4)(iv) above, there are two key issues that need to be addressed under the Draft Rules for the U.S. clean hydrogen economy to be successful and for 45V to enable the growth in clean hydrogen that was intended by the Biden Administration: (1) a clean hydrogen facility's ability to ensure the level of 45V credit its production methodology will generate and (2) the ability for clean hydrogen producers to operate at high capacity factors (at or near continuous operations) on an instantaneous basis (where it might not have visibility into the corresponding EACs being generated instantaneously) in order to serve existing and new hydrogen markets. Further details on these additional proposals are provided in Article IV.

The following Articles provide a more detailed analysis of each of the requirements described above, the implications the Draft Rules will have on the U.S. clean hydrogen market if not modified, and guidance on revising the Draft Rules to better support the nascent clean hydrogen industry while still upholding the integrity of the Three Pillars. We believe the proposed modifications to the Draft Rules will preserve the legacy of the Biden Administration, catalyzing the U.S. clean hydrogen market, generating countless jobs in new, clean technologies, preserving the Three Pillars of renewable energy, and driving America's decarbonization efforts.

Thank you, again, for the opportunity to comment on the Draft Rules and for your consideration of our comments and proposals. We firmly believe the United States can be the world leader in the production of clean hydrogen, and we hope to play a key role in that success alongside the Biden Administration. We look forward to supporting you in this endeavor and would be happy to meet with you to consider any of the thoughts, comments or proposals set out in this letter, or any other issues you may wish to discuss.

Sincerely,

Cameron MacDougall

General Counsel

Article I: Temporal Matching

Section I(A): The Draft Rules on Temporal Matching

Proposed § 1.45V–4(d)(3)(ii)(A) would provide the general rule that an EAC satisfies the temporal matching requirement if the electricity represented by the EAC is generated in the same hour that the taxpayer's hydrogen production facility uses electricity to produce hydrogen. Proposed § 1.45V–4(d)(3)(ii)(B) would provide a transition rule to allow an EAC that represents electricity generated before January 1, 2028 to fall within the general rule provided in proposed § 1.45V–4(d)(3)(ii)(A) if the electricity represented by the EAC is generated in the same calendar year that the taxpayer's hydrogen production facility uses electricity to produce hydrogen.

Section I(B): Issue with current draft

I(B)(1): Temporal Matching, as proposed in the Draft Rules, will result in a material disadvantage for geographies that currently have a lack of existing or planned renewable energy as outlined in Sections I(B)(2) – I(B)(3), including a significant mix of wind generation needed to meet hourly matching as shown in Sections I(B)(3) – I(B)(4), or regions which have historically long timelines and low success rates for the development of new renewable projects as detailed in Section I(B)(3). In addition, a premature transition to hourly matching while there are significant differences in the amount of renewable energy assets between geographies, will impose significant disadvantages for clean hydrogen projects in regions with limited renewable energy supply due to excessive renewable costs (resulting in fewer EAC options). This cost disparity between regions with fewer renewables will ultimately increase the cost of clean hydrogen, which will either make it harder for offtakers in those regions to adopt clean hydrogen; or it will drive new clean hydrogen developments into regions with lower renewable energy costs, many of which are farther from the end users of clean hydrogen which creates an infrastructure problem for offtake. Lastly, there are limitations in the accounting systems related to EACs, which will prevent many regions from being able to offer around-the-clock hourly matching of EACs, as noted in Section I(B)(7).

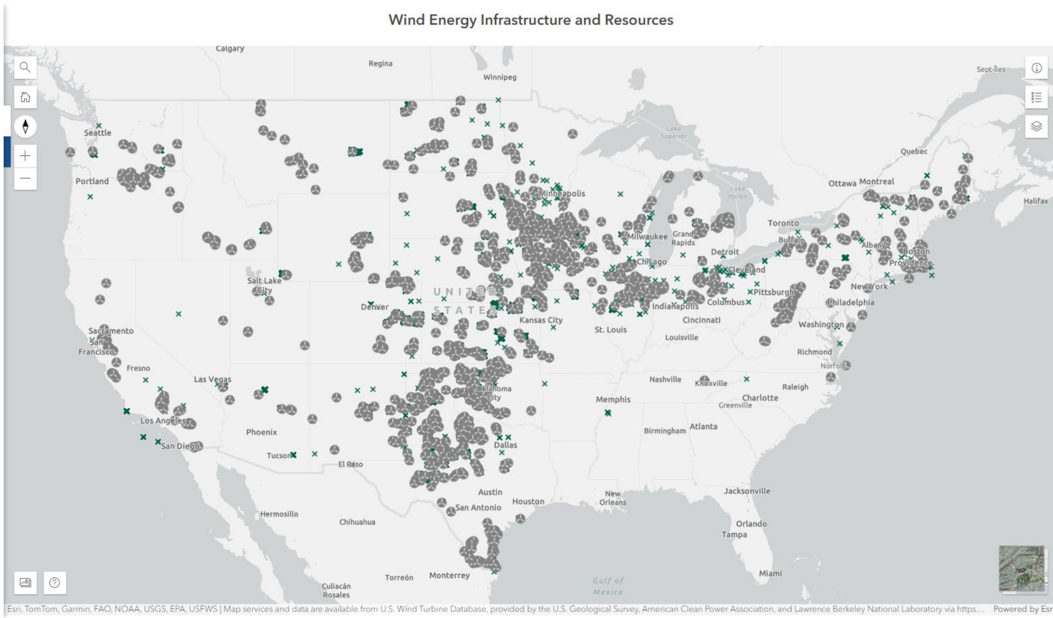
I(B)(2): If all regions in the U.S. are not given adequate time for renewable projects to mature, especially those with few existing renewables and high development or interconnection timelines, it will cause a material disadvantage between geographies, based on EAC resource adequacy, as hourly matching is required. For example, the renewable energy development cycle (interconnection request to final operation or COD) across the U.S averages 5 years[2]. While the renewable energy development cycle in the Electric Reliability Council Of Texas (“ERCOT”) region (Texas region as defined by the DOE’s National Transmission Needs Study of October 2023) generally ranges from 1.5 to 2.5 years[3]. Therefore, clean hydrogen projects located outside of ERCOT, as an example, will be at a material disadvantage if hourly matching is required per the Draft Rules (2028 hourly matching) before adequate wind and solar resources are operational in those regions. This disparity is especially true for regions like the Midcontinent Independent System Operator (“MISO”) Delta region which has no operating wind assets as of the writing of this Article. The disparity in renewable assets between regions is visualized in the map in Figure 1, which shows all active wind generation assets in the U.S. per the EIA. As shown in Figure 1, there is nearly no wind generation in the Southeast U.S., which is needed for hourly matching. Based on the lack of wind asset and development hurdles for new wind

[2] According to research from the Lawrence Berkley National Laboratory: https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf

[3] Per the recent ERCOT Resource Interconnection Handbook: https://www.ercot.com/files/docs/2021/01/07/Resource_Interconnection_Handbook_v1.94_03012023.docx

projects, if the current Draft Rules are not modified it will result in certain regions not being able to participate in the clean hydrogen market due to an inability to satisfy hourly matching.

Figure 1: Renewable Wind Assets by Location via EIA



I(B)(3): Additionally, the share of new projects that request interconnection and reach COD are disproportionate across regions in the U.S. As illustrated in Figure 2 below, the ISO-NE and ERCOT regions are the only geographies that exceed a 30% completion rate (19% and 24% on a capacity-weighted basis, respectively), per research published from Lawrence Berkley National Laboratory[4]. This means in regions like MISO, the withdraw rate (or the removal of projects from the queue) of all new energy generation projects in the Interconnection Request ("IR") queue is approximately 76%. Of the total projects in the MISO IR queue, only 23% are wind and solar. This is especially concerning as the current Draft Rules have split MISO into the MISO-Delta and MISO-Midwest regions and the Delta region has zero wind generation in operation today according to the MISO wind and solar planning report[5]. Using the approximate 5-year timeline for projects to become operational, only wind projects which are nearing completion of the MISO interconnection study (the IR process results in an interconnection study that yields interconnection requirements) and are nearing execution (which can take 12-24 months to physically build) would be able to support hourly matching by 2028. At the date of these comments, the total capacity of wind projects in the MISO-Delta IR queue equates to roughly 2 GW (name plate capacity). With an average withdraw probability rate of 76% (as indicated by a 24% success rate for projects in the IR queue, per Figure 2) the resulting wind nameplate capacity would be 460 MW, with the earliest projects coming online 2027-28. For reference, a typical wind capacity factor (or the percentage of actual MWh generated from the nameplate capacity in each 24 hour day) is around 40%. This means of the 460MW of nameplate capacity in the MISO-Delta IR queue, only roughly 184 effective MW would be available, which is not adequate to support a 100MW facility per Section I(B)(4), below.

I(B)(4): As an example, using a 100 MW electrolyzer (plus 20 MW for ancillary plant load) and historical wind and solar generation data from ERCOT (since none exist in MISO-Delta), an estimated 350 MW in renewables

[4] https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf
[5] https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf

is needed to support a >90% capacity factor as shown in Table 2, below. Of that 350 MW, ~70% (250 MW) wind energy is needed to achieve an hourly EAC generation profile. Thus, if there is more than one clean hydrogen project in the MISO-Delta region (currently there are numerous planned projects - estimated at over 500 MW by 2028 according to market intel), and the 2028 hourly match requirements remains, there will not be enough wind resources to service the market on an hourly basis. This will cause many planned clean hydrogen projects in MISO-Delta to either move to a region with more EAC options or to operate at a lower capacity factor by only operating during times of the day when it can match EACs. The latter scenario, while not technically feasible today, as noted in Section I(B)(7), will significantly increase economic hurdles for projects and cause significantly higher clean hydrogen costs, as detailed below in Table 1.

Table 1: Illustrative Comparative Costs of Production at High vs. Low-Capacity Factors

Illustrative Green Hydrogen Price Comparison *(High vs. Low Run-time scenarios)*				
	1. High Capacity Factor		**2. High Capacity Factor**	
Nameplate Hydrogen Plant Size	100 MW		100 MW	
Nameplate Hydrogen Production	45 TPD		45 TPD	
Hydrogen Plant Run-time	**100%**		**50%**	
Cost of Power	$60 MWh		$60 MWh	
Annual Costs of Hydrogen Production:				
	$/kg	**$/mm**	**$/kg**	**$/mm**
Power Costs	$3.52	$57.8	$3.52	$28.9
Water Costs	0.03	0.5	0.03	0.2
Other Fixed Costs	1.22	20.0	2.44	20.0
Total Annual Costs	**$4.77**	**$78.3**	**$5.98**	**$49.1**

** Include estimated 10% balance of plant power requirement.*
*** Assume 4 gal per kg of hydrogen and $7.00 per thousand gals of water.*
**** Include labor, plant O&M, insurance, etc.*

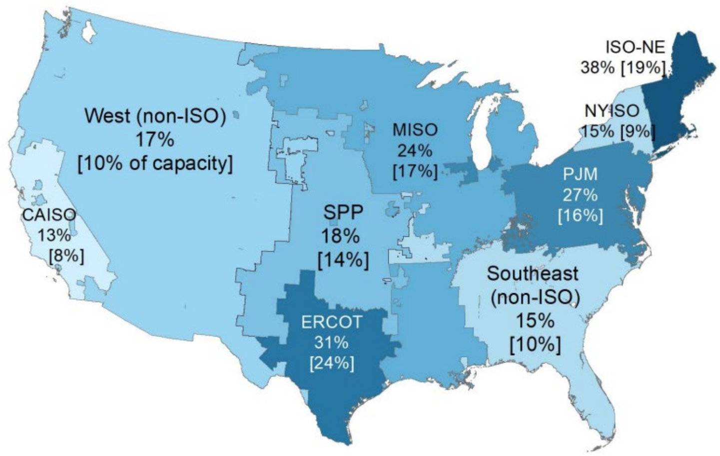
Table 2: Illustrative Required Renewables to Meet Hourly Matching[6]

Illustrative Required Renewables to Meet Hourly Matching *(Solar + Wind Portfolio Mix)*						
				Nameplate Solar		100 MW
Nameplate Green Hydrogen Facility			100 MW	Nameplate Wind		250 MW
Time	Hour	Solar Capacity Factor	Wind Capacity Factor	Effective Solar MW	Effective Wind MW	**Total Effective MW**
12:00 AM	0	0%	50%	--	125	**125**
1:00 AM	1	0%	45%	--	113	**113**
2:00 AM	2	0%	45%	--	113	**113**
3:00 AM	3	0%	45%	--	113	**113**
4:00 AM	4	0%	40%	--	100	**100**
5:00 AM	5	0%	40%	--	100	**100**
6:00 AM	6	5%	40%	5	100	**105**
7:00 AM	7	15%	40%	15	100	**115**
8:00 AM	8	45%	35%	45	88	**133**
9:00 AM	9	55%	35%	55	88	**143**
10:00 AM	10	60%	33%	60	81	**141**
11:00 AM	11	65%	30%	65	75	**140**
12:00 AM	12	70%	30%	70	75	**145**
1:00 PM	13	70%	30%	70	75	**145**
2:00 PM	14	65%	33%	65	81	**146**
3:00 PM	15	60%	35%	60	88	**148**
4:00 PM	16	55%	35%	55	88	**143**
5:00 PM	17	35%	35%	35	88	**123**
6:00 PM	18	15%	35%	15	88	**103**
7:00 PM	19	5%	40%	5	100	**105**
8:00 PM	20	0%	45%	--	113	**113**
9:00 PM	21	0%	48%	--	119	**119**
10:00 PM	22	0%	50%	--	125	**125**
11:00 PM	23	0%	50%	--	125	**125**
Average		**25.8%**	**39.3%**	**26**	**98**	**124.0**

***Note: Capacity Factor estimates based 2022 UL Services Group ERCOT Study*

[6] https://www.ercot.com/files/docs/2021/12/07/Report_ERCOT_1980-2020_WindSolarDGPVGenProfiles.pdf

Figure 2: Share of Project Requesting Interconnection from 2000 – 2017 that have Reached COD



I(B)(5): As demonstrated in the previous example in Section I(B)(4), many regions, like MISO-Delta and the Southeast, simply cannot offer around-the-clock, hourly matched EACs without ample time to build out more renewables. If hourly matching is required too early, one resulting scenario for projects built in those regions will be to force those clean hydrogen plants to run at a lower operational capacity factor, as EACs are not available on an hourly basis. This is especially concerning because most industrial offtakers which are likely to use the clean hydrogen (i.e. renewable diesel refining, E-fuels, petrochemical, and agriculture or fertilizer) will require a constant flow of hydrogen to maintain safe and reliable operations. Requiring hourly matching by 2028, before all regions in the U.S. have adequate time for renewable energy to proliferate, will result in either certain regions failing to offer hourly EAC capability on a near 24x7 (around-the-clock) basis sufficient to serve industrial decarbonization with clean hydrogen; or as stated earlier, the hydrogen projects will be forced to restrict production, jeopardizing the operational continuity of the industrial offtakers that are being supplied which will materially limit offtaker optionality, slowing decarbonization and clean hydrogen adoption.

I(B)(6): As noted above in Section I(B)(5), clean hydrogen projects need a high capacity factor (ideally as close to 24x7 run time as possible) so they can spread their fixed costs across a greater volume of product, thus achieving a lower levelized costs of hydrogen ("LCOH"). The need for a lower LCOH will be especially critical in the early years of the U.S. clean hydrogen market, where project costs are likely to be elevated due to limited market experience and higher technology costs. A lower LCOH will help early clean hydrogen projects secure offtake by reducing the cost premium for using clean hydrogen. For example, using basic project estimates and only changing run time, a 50% change in capacity factor (ex. 24 hours / 7 days schedule vs 12 hours / 7 days schedule), results in an approximately $2.00/kg change in the cost of clean hydrogen. Given many early clean hydrogen projects are targeting offtake to existing users of grey hydrogen, a $2.00/kg increase in cost will prove to be too high for an end user due to the relatively low cost of existing grey hydrogen. For context, according to research by Bloomberg NEF, shown in Figure 3 below, the levelized costs of grey hydrogen (derived from natural gas) is $1 – $2/kg, while the levelized costs of green hydrogen is around $6/kg (using a 100% capacity factor). Additionally, the DOE's National Clean Hydrogen Strategy and Roadmap[7] states PEM ELX H2 of $5/kg (based on $50/MWh power). If a clean

[7] https://www.energy.gov/sites/default/files/2021-09/h2-shot-summit-plenary-doe-overview.pdf

hydrogen producer must now add an additional $2.00/kg to the already higher cost of clean hydrogen, it would prove detrimental for most clean hydrogen projects. Alternatively, if clean hydrogen can operate with a higher capacity factor and include the full IRA 45V credit of $3.00/kg, the resulting levelized cost of clean hydrogen, around $2.00 - $3.00/kg, would become more competitive with grey hydrogen.

Figure 3: Levelized Costs ("LCOH") of Green vs. Grey Hydrogen[8]

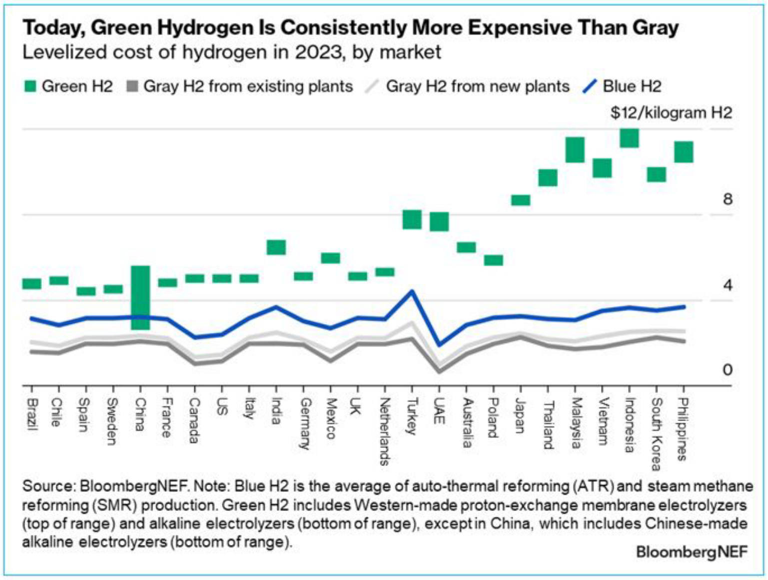


Figure 4: Hydrogen Costs of Production – Grey vs. Blue vs. Green

Getting to know the hydrogen color palette

Color	Definition	Average production cost in 2023
Gray	Produced from natural gas without abatement	$2.13 per kilogram
Blue	Produced from natural gas with carbon capture	3.10
Green	Produced from water electrolysis using renewable electricity	6.40

Source: BloombergNEF — BloombergNEF

I(B)(7): One final limitation for requiring hourly matching by 2028 is the lack of real-time capabilities and standardization in the EAC tracking and accounting systems. There are several technological gaps that must be addressed before hourly matching is required under the IRA 45V. As noted above in Sections I(B)(5) – I(B)(6), early clean hydrogen projects ideally need to operate as close to a 24x7 production profile as possible. EACs, more specifically RECs, are minted for every 1 MWh of renewable energy generation, with those RECs typically becoming available months after the date of generation. Thus, in the context of operating a clean hydrogen facility that is not directly connected to an EAC generator, there is virtually no way to reasonably match the real time amount of renewable energy generation to hydrogen production without a material level of risk. This is especially critical if the clean hydrogen facility will take a CI penalty based on an aggregate CI score for producing any portion of hydrogen via grid power, as is understood in the current Draft Rules. This point is supported by the renewable energy capacity factor referenced in the example of Section I(B)(4), above. This means, unless the clean hydrogen producer is directly connected to the renewable energy

[8] https://about.bnef.com/blog/green-hydrogen-to-undercut-gray-sibling-by-end-of-decade/

generator and can curtail operations as EACs are not being generated, which has its own challenges, it will have very few operational choices if hourly matching is required before the needed technologies exist. For example, a clean hydrogen plant, operating under an hourly matched EAC profile and grid connected, will have to either commit to excess (over subscribe) EAC generation assets to limit the probability that it won't have EACs during the hours it plans to operate; or it will have to deploy some form of predictive intelligence (AI) for the generation of EACs based on some historical and meteorological input. Note the latter option is not known to exist, commercially, as of the writing of this Article. This will undoubtedly result in instances where a clean hydrogen production facility is operating under the assumption it has the corresponding EACs, when it does not. It should be noted, there are companies within the renewable energy space which recognize and are focused on solving the complexities of real-time renewable generation and more time is needed for those predictive solutions to materialize. An additional concern is the lack of an EAC registry standard, or the fact that not all regions have a registry, and those that have a registry have varying times for an EAC to be minted, becoming available for use. EACs are commonly only minted with reference to the year or month, with only a few registries stamping EACs with hourly generation information (M-RETS and PJM, to name a few). However, even hourly stamped EACs are minted and available for use several months after the generation date. An example of this can be found on the Environmental Information Service's PJM REC Bulletin Board[9], which shows tradable RECs that are roughly 2 months or older.

Sec. I(C): Proposed Solution:

The below proposal and justification for time matching is an effort to uphold the intent of temporal matching, whereby EACs are used to limit overall and incremental grid emissions, while fostering the necessary development environment that is required for the proliferation of clean hydrogen in the U.S. We propose a grandfathering provision over a 10-year term, whereby clean hydrogen facilities which start construction before January 1, 2028, would be allowed annual matching for the first five (5) years after reaching COD, with a transition to quarterly matching at year six (6) until year ten (10). Additionally, for those projects which begin construction before January 1, 2028, we propose a standard, four (4) year safe harboring provision. For qualifying clean hydrogen facilities which begin construction after January 1, 2028, the time matching requirements would be phased in gradually, with annual matching to apply until 2030, quarterly matching to apply from 2030 to 2035, and hourly matching to apply beginning in 2035. This gradual transition will allow regions with limited renewable resources, like MISO-Delta, to have enough time to 'catch-up' to regions with more available renewable assets, like ERCOT or MISO-Midwest. These changes will create a level playing field for all regions in the U.S. and eliminate and regional differences which will be present under the current Draft Rules as outlined above in Sections I(B)(1) - I(B)(3). The regional differences resulting from strict time matching will only be resolved by providing adequate time for new renewable projects to be built in support of clean hydrogen production. Further, the transition in 2030 from annual to quarterly matching will resolve any concerns over seasonal EAC generation dynamics, whereby the generation profile of renewables varies greatly by season (i.e. higher solar generation in Summer compared to winter). This will also allow new clean hydrogen projects, which are not grandfathered, to design those facilities to manage seasonal constraints and to develop EAC sourcing strategies with a proper EAC asset mix in preparation for stricter time matching. This proposed solution maintains the Biden Administrations commitment to hourly matching, supports the continued growth of American clean energy, and provides the flexibility needed by the new clean hydrogen industry to unleash billions in new clean hydrogen investments in the U.S.

[9] https://gats.pjm-eis.com/gats2/PublicReports/BulletinBoard/PurchaseRequests

Sec. I(D): Justification:

Zero's proposed solution provides consideration for the following:

- I(D)(1): as discussed in Section I(B)(1) – I(B)(3), transitioning to hourly matching in 2035 allows regions, which currently are unable to offer hourly matching due to having fewer renewable energy assets, the time necessary to develop and construct new renewable projects needed to support hourly matching. This will afford regions with few EAC resources to 'catch-up' to other regions with more renewables and level the field, allowing all regions to participate in the new clean hydrogen market; and

- I(D)(2): as mentioned in Section I(B)(4) – I(B)(6), a gradual transition to strict time matching will give the nascent clean hydrogen market the ability to realize a higher capacity factor by allowing more time for renewables to be built in regions that cannot offer around-the-clock, EAC time matching due to the scarcity of renewable assets. As noted in Section I(B)(4), a high capacity factor is critical for the success of clean hydrogen production facilities to meet industrial offtaker requirements and provide a continuous supply of clean hydrogen for those offtakers to decarbonize; and

- I(D)(3): as referred to in Section I(B)(6), a gradual transition period for hourly matching would afford more time for regions lacking renewable assets, or those with long development timelines, to build additional renewable capacity. More renewable capacity in the U.S. will, over time, reduce the cost of EACs in the market and provide opportunity for higher hourly EAC capacity factor, ultimately lowering the overall cost of clean hydrogen, making the transition to clean hydrogen financially sustainable and will lead to higher rates of decarbonization; and

- I(D)(4): as mentioned in Section I(B)(7), by shifting the deadline to hourly matching to 2035, the EAC accounting systems, which do not all currently support hourly matching on an instantaneous basis, will have time to develop and standardized. As noted in Article IV, Section (ii), EACs are generally established and tradable one to two months following the generation date, if hourly time matching is required prematurely, it will result in a new and significant risk associated with producing hydrogen that does not have an EAC to cover that period of production. This risk is further detailed in Article VI, Section (iv) whereby a clean hydrogen facility will realize a higher carbon intensity if operating via grid connection and without corresponding EACs to match hour by hour, which is not possible in today's EAC trading or accounting environment; and

- I(D)(5): as mentioned in I(B)(7), by requiring a transition from annual matching to quarterly matching, it will give regions and renewable energy developers a target to meet stricter time coincidence to support clean hydrogen producers. In this case, seasonal demand will drive regions to add the renewable generation mix necessary to account for seasonal differences in EAC generation profiles (i.e. historically solar has a lower generation profile in winter than summer). A transition to quarterly matching will also address EAC vintage concerns whereby the age of EACs will be more closely matched to their use in clean hydrogen production. Thus, quarterly matching will help to uphold the integrity of renewable energy used for clean hydrogen by eliminating the ability to source the bulk of EACs during the summer months only from solar, for example. Additionally, the transition from annual to quarterly matching will begin pushing the clean hydrogen and renewable energy markets to manage EAC portfolios with a focus on time of use. This gradual transition could also help the market build capabilities for stricter time matching in the buildup to hourly matching, by helping establish the accounting and data sharing needs for tighter matching tolerances with clean hydrogen operating conditions. The proposed transition timeline solves a notable concern of the voluntary EAC market, specifically in reference to the use of Renewable Energy Certificates ("RECs"), which is the vintage of RECs being used to offset scope 2 emissions. As an example, Green-e RECs have a shelf life of 21 months, as such they can be purchased and retired for Scope 2 emissions a year after the renewable energy was generated, which does very little to offset actual grid emissions due to seasonal and grid load variances year over year.

Article II: Incrementality

<u>Sec. II(A), The Draft Rules:</u>

Proposed § 1.45V–4(d)(3)(i)(A) would provide that an EAC meets the incrementality requirement if the electricity generating facility that produced the unit of electricity to which the EAC relates has a COD (as defined in proposed § 1.45V–4(d)(2)(i)) that is no more than 36 months before the hydrogen production facility for which the EAC is retired was placed in service.

<u>Sec. II(B), Issue with current draft:</u>

II(B)(1): Strict incrementality requirements with respect to renewable generation used to produce clean hydrogen will cause a disadvantage to regions with significant MEG capacity and for regions with limited existing renewables or extended timelines for developing new renewable generation assets. Under the current Draft Rules, regions with high concentrations of MEGs will largely be excluded from participating in the clean hydrogen market unless there are clear and meaningful pathways for MEGs to meet Incrementality. Regions with high concentrations of existing renewable energy assets, which are outside the 36 month threshold but having usable life, will also be excluded from participating in the clean hydrogen market under the current Draft Rules. Incrementality, without certain exceptions, or grandfathering, will cause an imbalance between geographies in the U.S. and will drive new clean hydrogen projects only into those regions with renewable assets which meet ridged incrementality requirements.

II(B)(2): Additional concerns which the nascent clean hydrogen market must navigate, are the significant hurdles around the newness of clean hydrogen developments, including using new and relatively unproven production technologies, like Proton Exchange Membrane (or “PEM”). Many new clean hydrogen electrolysis projects intend to use PEM electrolysis technology due to its higher efficiency and compact footprint, as compared to typical alkaline electrolysis. For example, the largest PEM in commercial operation today[10] is roughly 40 MW, which is one fifth the scale of Zero’s Beaumont project (a proposed 200 MW). The development risks for clean hydrogen projects, including technology risk, will become prohibitive, potentially un-bankable, if that risk is also coupled to the development risk associated with the renewable energy projects it will need to support incrementality under the Draft Rules. Renewable development risk is a significant concern, as detailed in Section I(B)(3) above. If strict incrementality is required for clean hydrogen facilities, it would likely cause new clean hydrogen projects to only develop in geographies with adequate renewable resources that meet the incrementality requirement. Excessive development risk, resulting from strict incrementality, will likely be a barrier to the market for many early entrants to the clean hydrogen market, especially small businesses or startups trying to develop clean hydrogen projects. These small business and new entrants to the hydrogen market will be disadvantaged if not significantly funded (or with strong financial backing) or they will only be able to build projects in regions with adequate new EAC assets, further causing regional differences because of the Draft Rules. This instance will be more prevalent in the early years of the IRA era and in regions with few renewable energy assets as outlined in Section I(B)(2).

II(B)(3): As noted in Section I(B)(3), the development hurdles associated with renewable energy projects, coupled with strict Incrementality in the early years of the clean hydrogen market, would unfairly force clean hydrogen developers to pair (in schedule) their projects to the renewable energy projects that will provide them EACs. This burdensome coupling effect is due to the nature of renewable energy project development, where EAC project developers do not typically reach financial commitment until they pass the interconnection queue process and sign binding offtake for the energy (or EACs only) they will generate. This would be

[10] https://www.ir.plugpower.com/press-releases/news-details/2024/Plug-Power-Starts-Production-of-Liquid-Green-Hydrogen-at-its-Georgia-Plant/default.aspx

prohibitively burdensome as the clean hydrogen developer will have very little control and limited recourse if the renewable projects it chooses fail to materialize or are significantly delayed. This issue will be further magnified in regions with few existing or planned renewable projects or those with excessively long development timelines as detailed in Section I(B)(3) and I(B)(4). For example, in regions like MISO-Delta, the clean hydrogen developer will need to commit to EAC offtake (PPA or VPPA) from renewable projects very early in the EAC project schedule (long before construction) to have EACs available when the clean hydrogen project reaches COD. If the renewable project in this example is delayed or fails, there are very few options or solutions for the clean hydrogen facility due to the lack of resources and planned project success rate. This risk is magnified due to the 5+ year EAC project development cycle and lack of existing EAC assets in the MISO-Delta region per Section I(B)(2) – I(B)(4). This issue will be more prevalent in the early years of the market and while there are significant differences in renewable assets (existing and planned) between geographies in the U.S.

II(B)(4): In addition to the risks associated with coupling new renewable energy projects to the clean hydrogen market, MEGs are also at risk of being excluded if not given options to meet incrementality. MEGs pair well with clean hydrogen production, where the low marginal cost of MEG generation and ability to easily service a 24x7 power shape (generation profile) would help lower the overall cost of clean hydrogen for hard to abate sectors (i.e. industrial applications). However, if MEGs are required to meet strict incrementality, it will put many regions with high concentrations of MEGs at a disadvantage due to the scale and nature of new MEG projects and lack of uprate capacity. In regions largely supported by MEGs, this could further contribute to retirements of MEGs, whose total generation has been trending downward as illustrated in Figure 5, below. This downward trend is hard to attribute to specific cause but is likely influenced by regional pricing pressures (negative marginal pricing) associated with increasing amounts of renewable energy generation being added to those regional grid systems without the ability for MEGs to source load or curtail non-detachable energy generation very easily. However, as the current Draft Rules attempt to contemplate various pathways for a MEG to qualify for incrementality, the methods proposed are burdensome and difficult to justify. As an example, retirement avoidance is very difficult to justify solely based on a new clean hydrogen load, due to the scale of (many) existing MEGs compared to that of new clean hydrogen facilities and the dynamics of economic variables in regional energy markets. If incrementality for MEGs is required without pathways for participation in new clean hydrogen projects, it will further drive unfavorable market conditions as more renewable assets come online and the MEGs don't have options for new load. This unfavorable market condition is caused by negative Locational Marginal Price ("LMP") or marginal price, which occurs when the grid is in an oversupply situation or there is an undercutting bid market due to the lack of material ability to curtail renewables or MEGs. Note: negative marginal pricing can also occur for other economic reasons not covered in this passage. A noteworthy consideration for MEGs is their general inability to reduce energy generation rates quickly or significantly as many MEGs are ideally operated at base load (or steady state operation).

Figure 5: U.S. Nuclear Capacity Trends[11]

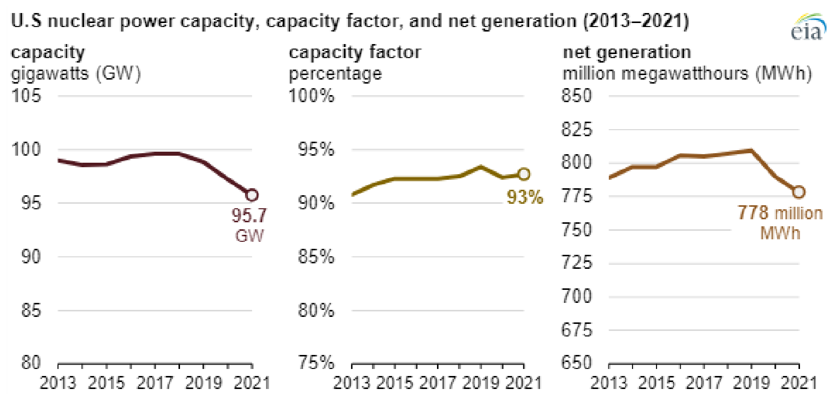
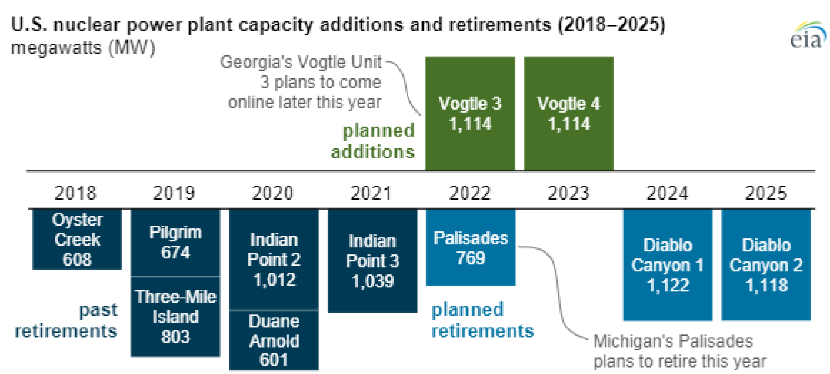


Figure 6: Planned Retirements and Additions of U.S. Nuclear Assets[12]



II(B)(5): If MEGs are required to meet strict incrementality, it will have a significant and negative impact on the recently approved DOE hydrogen hub projects. There are approximately 3 DOE Hydrogen Hubs that are currently planning on sourcing energy for clean hydrogen from MEGs, of which all are at risk of not qualifying for clean hydrogen production credit, under the current Draft Rules. These hubs include the Mid-Atlantic (MACH2) and Midwest (MachH2), which were established under the pretense of utilizing low-cost nuclear power for clean hydrogen production, as well as the Pacific Northwest (PNW H2), which was establish with the intent of utilizing hydroelectric power in the production of clean hydrogen. Incrementality for MEGs will put those projects at a material disadvantage compared to projects in other regions if the clean hydrogen tax credit cannot be realized. Ultimately, the Draft Rules would be in opposition to the IIJA which the Biden Administration successfully championed in support of fostering the U.S. clean hydrogen market.

II(B)(6): In a similar situation to MEGs, existing renewable energy assets that are no longer operating under a PPA (as an example) and have usable life could also be excluded from participating under the current Draft Rules. These renewable energy assets would likely be limited to a smaller base of offtakers or would be forced to sell EACs into the voluntary market, which varies in value significantly by region. If not given the ability to participate in the clean hydrogen market it could result in premature and wasteful retirement of usable renewable energy assets. This scenario would put regions with abundant, aging renewable assets at a

[11] https://www.eia.gov/todayinenergy/detail.php?id=51978
[12] https://www.eia.gov/todayinenergy/detail.php?id=51978

disadvantage to those geographies which are actively building out new renewables or those that have shorter lead times for renewable projects, if not given the opportunity to attract new load, like clean hydrogen projects. Notably, the Biden Administration has supported the expansion of renewable energy in the U.S. and it would significantly diminish the legacy of the Biden Administration to inadvertently cause the early retirement of renewable energy which has useful life and could support the clean hydrogen market. An added result of strict incrementality is an increasing demand for new renewable energy projects that will ultimately cause a material increase in PPA pricing. Scarcity of demand for EAC projects, as detailed in Section I(B)(3) and I(B)(4), will add another element of risk and increase costs associated with building a new green hydrogen production facility, which as outlined in Section II(B)3 is already dependent on being coupled with new renewables generation. Renewable energy pricing data is tracked by industry and, as seen the PPA Index[13], wind and solar PPAs in 2020 averaged $25 - $30/MWh and by 2Q 2022, wind and solar PPA pricing had risen to over $40/MWh and $35/MWh, respectively.

Section II(C), Proposed Solution:

II(C)(1): Incrementality, while important for the overall buildout of a cleaner U.S. grid, should not hinder first movers due to regional differences in renewable energy availability. Rather, for the clean hydrogen market to be successful and the IRA 45V to foster the market's development, incrementality should be phased in as renewable assets are built out and the risks associated with the early clean hydrogen market are not as prevalent. In addition, incrementality should provide a fair playing field, as detailed in this Section II(C), for regions with few new renewable energy sources, or for MEGs, or regions with an aged fleet of renewable energy, which could be re-dispatched for clean H2 production.

II(C)(2): Zero proposes allowing a grandfathering provision whereby a clean hydrogen facility which begins construction by January 1, 2028, with a standard 4-year safe harbor provision, or that reaches COD by January 1, 2030, is not required to source EACs with the 36-month time constraint as detailed in the current Draft Rules. Clean hydrogen facilities that reach COD on or after 2030 will be required to meet Incrementality requirements with a 36 month look-back.

II(C)(3): Additionally, limitations with respect to sourcing renewable energy from MEGs should be modified to level the playing field for regions with high concentrations of MEG assets. This would allow MEGs to support the emerging clean hydrogen market while also supporting the development of new renewable energy assets in those regions. The following provisions would constitute rules around MEGs and incrementality:

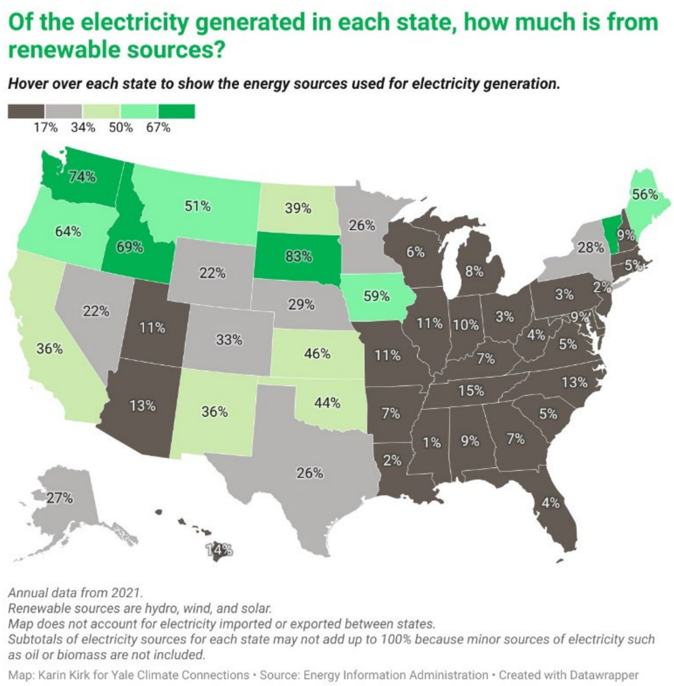
- II(C)(3.1): Concern around induced grid emissions which might be caused by a MEG diverting its existing load from the grid to a clean hydrogen facility, could be addressed under the Draft Rules by requiring MEGs to establish a PPA with the clean hydrogen facility, with an added provision containing an interruptible or curtailable power supply for regions where a MEGs power is in demand (no excess load). This would allow the MEG to run at a higher level of baseload operation and limit LMP pressures by utilizing the more price stable PPA construct. Additionally, the curtailment provision would limit induced emissions by eliminating the need for emitting generation to functioning as the grid's demand response, since the clean hydrogen facility could reduce load, allowing the MEG to supply that power back to the grid. In exchange for this

[13] https://www.opisnet.com/blog/recs-bottlenecks-expected-to-linger/

curtailment option, the clean hydrogen facility could benefit from the high capacity factor of MEG generation as well as favorable and stable power costs associated with MEG supply.

- II(C)(3.2): Incrementality should not be required for MEGs in regions with an established program for new energy generation to be non-emitting (or MEG) or in areas (or load zones) where the grid mix has a substantial level of clean power. For example, the Bonneville Power Market in Washington state, where certain areas of the grid are supplied from up to ~74% renewable energy generation from hydroelectric power, See Figure 7, below. Also, incrementality should not be required where new clean hydrogen load would not add incremental emissions.

Figure 7: Proportion of Power Generation that is Renewable by State[14]



- II(C)(3.3): Given the non-dispatchable nature of MEGs where they act as market "price takers" (meaning they cannot easily reduce generation if the LMP falls below its operational margin), there should be a provision for a MEG to reserve a maximum of 20% of its capacity for new clean hydrogen load, exempt from incrementality. This will help alleviate curtailment and early retirement justification for MEGs, which are difficult to quantify, as well as accommodate the scalability of the clean hydrogen market, without causing material differences between regions in the U.S. (notable those with disproportionate renewable energy assets).

II(C)(4): Zero proposes that existing EAC assets, which have usable life and are no longer obligated under a power supply agreement, should be exempt from meeting the incrementality requirements and should have the ability to support clean hydrogen facilities. This will help to alleviate early retirements of existing EAC assets by providing access to an additional commercial market other than the voluntary EAC market.

[14] https://yaleclimateconnections.org/2023/02/us-state-with-most-renewable-energy-production/#:~:text=A%20color%2Dcoded%20map%20of,second%2C%20third%2C%20and%20forth.

Section II(D): Justification:

Zero's proposed solution provides consideration for the following:

- II(D)(1): As noted in the above Sections I(B), I(D) and II(2)(3), a significant limitation for renewable energy supporting clean hydrogen is the lack of existing EAC generating assets and the limited success rate of planned EAC generating projects. For this reason, requiring only new projects to support clean hydrogen production, especially in the early years of the IRA era will cause significant differences between geographies based on the amount of renewable energy assets and timeline for adding those EAC resources. For this reason, Zero believes grandfathering for early clean hydrogen projects to forego strict incrementality, will allow for all U.S. regions to be strong candidates to participate in the clean hydrogen market and level the playing field; and

- II(D)(2): As discussed in Sections I(2), I(4), and II(2)(4)-II(2)(5), the difficult implementation of hourly matching EACs to the production of clean hydrogen, would be easily solved if MEGs are allowed to participate. MEGs can provide clean hydrogen facilities with high operational capacity factor since their generation is base load (24x7 operations) and very stable. Therefore, a MEG is an ideal candidate to supply clean energy to clean hydrogen production and will alleviate capacity factor concerns for clean hydrogen; and

- II(D)(3): An added benefit for the proposed incrementality rules, where grandfathering can be used for early projects and the conditional rules around MEGs and existing renewables (that fall outside the 36 moth window), would be a leveling of capabilities and offerings across all geographies, given not all regions have MEGs and not all MEG regions have strong existing or proposed renewable energy projects. The proposed incrementality provision would allow relief from restrictive rules for early clean hydrogen movers and bring new life to existing clean energy sources, which, ultimately, will uphold the integrity of the IRA and limit incremental or induced emission issues; and

- II(D)(4): MEGs offer an ideal clean energy source for clean hydrogen production facilities given their ability to support high up-times alleviating the issue presented in the Section I(2) with respect to hourly matching; and

- II(D)(5): As stated in II(B)(4), if not given access to new loads (like those of clean hydrogen facilities), MEGs will continue to act as price takers, where negative LMP (prices) occur, and a MEG isn't able to easily adjust generation rates so therefore it must absorb the negative generation cost for its power. This will be especially prevalent in regions with MEGs and a rapid proliferation of EAC assets as increasing levels of renewable generation (solar and wind) is brought online. As a result of negative marginal pricing, the U.S. could see more MEGs forced into early retirement. Note: negative marginal pricing is not typically a public data point and is only known in detail by the actual MEG owner; and

- II(D)(6): Uprating a MEG and justifying early retirement avoidance are extremely burdensome methodologies to use as qualifications for incrementality as proposed by the current Draft Rules. Existing MEGs in the U.S. will greatly benefit (and thus avoid early retirement) from the Biden

Administrations' historic IRA Nuclear PTC[15] provision, making it extremely improbable for the scenario where clean hydrogen would be the sole justification for retirement avoidance. Another notable issue is the intellectual property and proprietary information exposure a MEG owner would have to meet the proposed justifications under the current Draft Rules. Additionally, due to the age and scale of most existing nuclear and hydroelectric facilities, there is very little opportunity for existing MEGs to uprate; and

- II(D)(7): To avoid induced emissions in regions with no requirement for new power sources to be minimally emitting and where there is competition for a MEG's power (i.e. the MEG asset does not have available capacity), a MEG intending to supply a clean hydrogen facility could employ an interruptible (or curtailable) PPA with the hydrogen load. In the interruptible PPA scenario, when grid demand is high, the hydrogen producer can reduce rates (or curtail), allowing for more energy from the MEG to service the grid, reducing negative impacts of GHG-emitting generators load following. Though frequent intermittency for clean hydrogen production is not ideal for customer offtake (as outlined in these Articles) this commercial and operational philosophy could be more manageable if coupled to a MEG as curtailments will be less frequent and should afford proper planning and advance notice. A similar interruptible mechanism is demonstrated in practice today by utilities with interruptible tariffs where customers with large loads can curtail to support high grid demand in exchange for a lower power price. Programs also exist today like the Tacoma Public Utilities ("TPU") Electrofuels Tarriff, where the cost benefit of a MEGs low marginal operating cost is offset by the need for MEGs to service the grid and power market. Thus, the H2 producer in the TPU Electrofuels Tarriff acts as the demand response, curtailing/reducing its load whenever TPU requires additional power to supply the grid; and

- II(D)(8): As referred to in Section II(2)(5), the Draft Rules, as proposed, do not align with the DOE's efforts in establishing Clean Hydrogen Hubs with the intention of utilizing low-cost nuclear and hydroelectric power in the production of clean hydrogen given 3 of the of the 7 Clean Hydrogen Hubs were established with the stated intent of utilizing low-cost, reliable power via existing MEGs within those regions. This would be an unintended, negative result and would tarnish the Biden Administration's legacy as champions of clean and renewable energy in the U.S.

[15] https://www.energy.gov/ne/articles/inflation-reduction-act-keeps-momentum-building-nuclear-power

Section III: Deliverability

Section III(A): The Draft Rules:

Proposed § 1.45V–4(d)(3)(iii) would provide that an EAC meets the deliverability requirements if the electricity represented by the EAC is generated by a source that is in the same region (as defined in proposed § 1.45V–4(d)(2)(vi)) as the relevant hydrogen production facility. The regional constraints proposed in the Draft Rules limit geographies to the Balancing Authority level, apart from MISO, which is split between MISO-Midwest and MISO-Delta.

Section III(B): Issue with current draft:

III(B)(1): The Draft Rules, as proposed, do not provide consideration for sourcing EACs from interconnected and adjacent Balancing Authorities. As such, regions with fewer renewable energy generators and longer timelines for new projects to mature, will be at a disadvantage compared to regions which are further along with adding EAC generation or which have shorter development timelines. As noted in Sections I(2) and II(2), this geographical imbalance will be particularly high in the early stages of the green hydrogen market.

III(B)(2): Conversely, regions which have adequate renewable energy generation but do not have opportunities for the development of clean hydrogen production facilities due to a lack of existing hydrogen and industrial demand, will be disadvantaged as compared to other geographies with existing hydrogen demand centers. This will be especially impactful in the early stages of the clean hydrogen market before new market segments develop, (i.e. mobility, eFuels, etc.) which could support large scale clean hydrogen developments.

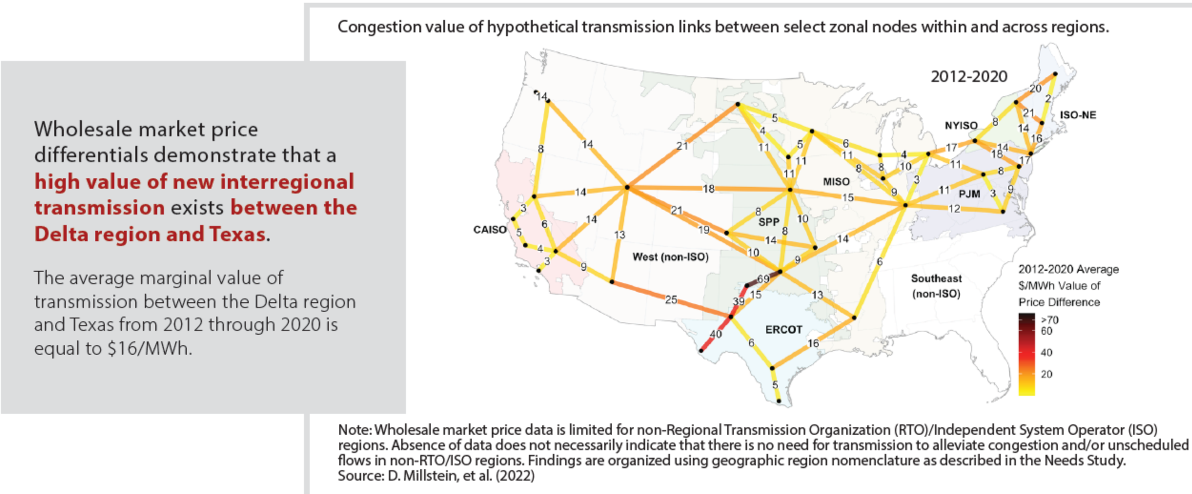
III(B)(3): As noted in section I(2) and II(2), there is a general lack of renewable energy sources across many of the Balancing Authorities in the U.S., which, under the current Draft Rules, will significantly limit the geographies where a qualifying clean hydrogen production facility can be developed. This will ultimately restrict the buildout of clean hydrogen to select geographies. Additionally, industrial decarbonization will stall in the U.S. along with the proliferation of renewables, more broadly due to the fewer resulting clean hydrogen opportunities for clean power offtake. Without the ability for both clean hydrogen facilities and EAC generating assets to support each other from interconnected and adjacent regions, it will cause a material imbalance in the ability to participate in the clean hydrogen market between regions in the U.S.

III(B)(4): Another issue with deliverability is identified by the DOE in the October 2023 National Transmission Needs Study[16] where, in summary, the U.S. grid is lacking sufficient interregional tie points (the energy transfer point between two Balancing Authorities where power is transferred). The U.S. grid would benefit from added tie points, so that Balancing Authorities can share resources during high or low grid demand scenarios as demonstrated during winter storm Uri in ERCOT in 2021. This issue is also compounded when there is an abundance of renewable energy, which is more difficult to curtail than conventional ghg-emitting power generation, causing high congestion issues due to a lack of load in the region. This issue will be further compounded under the Draft Rules, where stranded renewable energy assets will have limited ability to add load if there is no emerging clean hydrogen market in that region.

[16] https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf

III(D)(5): Figure 8, below, details the congestion points and clearly identifies the issues around stranded renewable energy, as noted in the West Zone of ERCOT, where there is an abundance of wind energy but inadequate load to use the renewable power (including very limited clean hydrogen development due to a lack of existing hydrogen demand).

Figure 8: Interregional Transmission Connection & Key Points of Congestion



<u>Section III(C): Proposed Solution:</u>

The Draft Rules should allow clean hydrogen producers with the ability to source EACs from adjacent and interconnected regions where tie points exist and can be verified, which can help develop more interconnections and cross regional transfers, as identified by the DOE in Figure 8, above.

<u>Section III(D): Justification:</u>

Zero's proposed solution provides consideration for the following:

- III(D)(1): Historically (as mentioned in Sections I(2),II(2) and III(2)) hydrogen demand centers (i.e. heavy industrialized regions, coastal regions with export capabilities, industrial corridors near major economic and population centers, etc.) exist in power markets with limited renewable energy or where sourcing renewable energy can be burdensome as a result of: limited qualifying renewable energy generation resources (qualifying as defined by the current Draft Rules); lengthy timelines and queues for the interconnection processes; limited land resources with adequate capacity for new renewable energy development; and strenuous permitting and siting requirements for new renewable energy generation; and

- III(D)(2): As identified to in Section III(2), adding interconnected regionality rules would allow for new clean hydrogen developments in all regions, which will drive job creation, decarbonization, and support new renewable generation projects. Additionally, by virtue of adding new load and clean hydrogen demand centers, more renewable energy sources will be needed as clean hydrogen expands to new market segments, thus supporting further renewable developments in all regions; and

- III(D)(3): In the early buildout of the clean hydrogen economy, efforts will likely be focused on existing industrial demand centers, while new markets segments continue to mature (i.e. mobility, etc.) and allowing for EAC sourcing from interconnected and adjacent regions, all geographies will be able to participate in the early clean hydrogen market. As an example of this, industrial grey hydrogen users, like ammonia producers, can support the transition to clean hydrogen at commercial scale whereas emerging clean hydrogen markets such as mobility, backup power, and long-duration energy storage, are not currently mature enough to endure significant hydrogen demand or offtake risk from an early clean hydrogen producer; and

- III(D)(4): As noted in Sections I(2), II(2) and III(2), addressing the geographical differences, which exist due to renewable energy availability and industrial hydrogen demand centers, if given the ability to source and supply EACs via interconnected and adjacent regions, it will foster growth for both renewable energy resources and clean hydrogen markets. This growth is due to more favorable EAC costs and more geographies capable of supporting projects that can qualify for the 45V credit incentive, which will reduce LCOH risk for new clean hydrogen production facilities.

Article IV: Other Notable Items

IV(i): Greet Model Consistency

Section IV(i)(A): As Proposed via IRS

Proposed § 1.45V–4(b) would provide procedures to calculate the lifecycle GHG emissions rate of hydrogen produced at a hydrogen production facility using the most recent GREET model as defined in proposed § 1.45V–1(a)(8)(ii) (referring to 45VH2–GREET). Proposed § 1.45V–4(b) would provide that for each taxable year during the period described in section 45V(a)(1), a taxpayer claiming the section 45V credit determines the lifecycle GHG emissions rate of hydrogen produced at a hydrogen production facility using the most recent GREET model.

Section IV(i)(B): Issue

The Draft Rules, as written, suggest there will be potential updates to the GREET model that is used to determine the CI of a clean hydrogen facility's product. This is concerning due to the potential for a clean hydrogen facility to qualify for a certain level of 45V credit and that 45V credit value could later change by virtue of an update to the GREET model, with no change to the facility's operational parameters (or renewable energy sourcing). This potential risk in the 45V credit value changing, due solely to a GREET model revision, will cause clean hydrogen projects expecting to receive a certain level of 45V credits to be financially risky. There is a significant amount of time, planning, and capital expenditures associated with building a qualifying clean hydrogen production facility, especially in the early stages of the clean hydrogen economy as project scale increases and new technologies are deployed. If there is additional uncertainty in a clean hydrogen facility's resulting 45V credit level, based on a revision to the 45H2V-GREET model, it will become a significant barrier for clean hydrogen projects to secure financing or equity funding. As noted in Article II(B)(2), adding 45V credit value risk to the technology and development risks, which already exists with clean hydrogen projects, would render clean hydrogen businesses and projects un-financeable, especially if 45V credits were considered in the project financial statements and proformas. Conversely, if there is uncertainty in a facility's level of 45V credit value over the duration of the IRA 45V term, it would stipulate that the facility addresses that risk by either reducing the economic impact of the 45V credit or by passing that risk on to its end user (commercially). Both options would ultimately diminish the intended impact of the IRA whereby the 45V credit is an enabler for clean hydrogen adoption by making it cost competitive with grey hydrogen.

Section IV(i)(C): Proposed Solution

There should be continuity between revisions to the 45H2V-GREET model, such that a facility that qualifies for a certain level of 45V credit based on its calculated CI score is not at risk of that CI score changing, solely due to a revision in the model and not from a change in its process variables. This could be accomplished by setting minimum limits, which cannot be revised, for the base variables, which constitute a calculated CI score based on a given production technology. An additional approach could be to set a provision whereby a facility is qualified under the version of the GREET model used at the time of COD for the 45V credit and bind that credit value for a period of ten years (assuming no process inputs change for the facility). This would provide certainty in a qualifying facility's anticipated level of 45V credit and support project financing. Naturally, changes to the GREET model could be made as more information about emission rates and new technologies becomes available, however, these revisions would be applicable to new projects and there would be a grandfathering of existing clean hydrogen facilities. In the same manner, if an existing clean hydrogen facility makes a modification to its process methodology, which impacts its core variables in the GREET model, it would then be required to re-calculate its resulting CI using the latest GREET model. Certainty of project economics is needed to ensure the ability to finance clean hydrogen businesses and projects.

IV(ii): EAC Registry Standards

Sec. IV(ii)(A): As Proposed via IRS

Proposed § 1.45V–4(d)(2)(ii) would define the term "energy attribute certificate" or "EAC" to mean a tradeable contractual instrument, issued through a qualified EAC registry or accounting system (as defined in proposed § 1.45V–4(d)(2)(v)), that represents the energy attributes of a specific unit of energy produced. An EAC may be acquired with or separately from the underlying energy it represents. An EAC can be retired by or on behalf of its owner, which is the party that has the right to claim the underlying attributes represented by an EAC. Renewable energy certificates (RECs) and other similar energy certificates issued through a registry or accounting system are forms of EACs.

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Proposed § 1.45V–4(d)(2)(v) would define the term "qualified EAC registry or accounting system" to mean a tracking system that (i) assigns a unique identification number to each EAC tracked by such system, (ii) enables verification that only one EAC is associated with each unit of electricity, (iii) verifies that the underlying attributes of each EAC is claimed and retired only once, (iv) identifies the owner of each EAC, and (v) provides a publicly accessible view (for example, through an application programming interface) of all currently registered electricity generators in the tracking system to prevent the duplicative registration of such generators. Qualified EAC registries currently include, but are not limited to, the following: Electric Reliability Council of Texas (ERCOT); Michigan Renewable Energy Certification System (MIRECS); Midwest Renewable Energy Tracking System, Inc. (M–RETS); North American Registry (NAR); New England Power Pool Generation Information System (NEPOOL–GIS); New York Generation Attribute Tracking System (NYGATS); North Carolina Renewable Energy Tracking System (NC–RETS); PJM Generation Attribute Tracking System (PJM–GATS); and Western Electric Coordinating Council (WREGIS).

Section IV(ii)(B): Issue

The current Draft Rules provide guidance for the base information that must be included for an EAC to qualify and be used in connection with clean hydrogen production, however, requirements for the frequency which an EAC is minted and the standards for instantaneous data (i.e. the instantaneous generation rates) are not included. The term "minting" means the point in time when an EAC (specifically a REC) becomes usable and tradeable on an EAC registry. The primary concern with EAC minting frequency is the delay between the generation date and minting date, which commonly takes one to two months for an EAC registry to mint the certificates after they are generated. Such a delay will lead to difficulty in matching EACs to clean hydrogen production by the hour. This delay will undoubtedly result in instances where a clean hydrogen producer is operating and assuming there is an adequate number of EACs being generated to cover their production, when there is not. Another issue with strict hourly matching before EAC standards for data and minting timing have been established across the renewable energy industry, is the 45V credit risk associated with operating a clean hydrogen production facility on an instantaneous basis when the accompanying EAC generation is inadequate. As noted in Section I(B)(7), the lack of forecasting capability, limited visibility into the real-time

EAC generation rate, and not having a standard for real-time data requirements will make it virtually impossible to operate with certainty of EAC coverage, without significant risk. This operating risk is further outlined in Section IV(iv)(A), below. Additionally, without a standard for EAC registries, and the need for all regions un the U.S. to have an EAC registry, it will cause disparity between regions which have no registry in place or those with no provision to use another registry.

Sec. IV(ii)(C): Proposed Solution

The Draft Rules should further define a national standard for all EAC registries and create a universal registry, with requirements around the timing for an EAC to be minted and the quality of the data provided by renewable generators. Given there are many EAC accounting tools in use today and, to eliminate the wasted effort of those tool developers, the specific data and timing requirements for the IRA 45V could be mandated without the specific need for a national platform or accounting tool.

IV(iii): 45H2V-GREET Grid Boundaries

Sec. IV(iii)(A): As Proposed via IRS

Proposed § 1.45V–4(d)(3)(iii) would provide that an EAC meets the deliverability requirements if the electricity represented by the EAC is generated by a source that is in the same region (as defined in proposed § 1.45V–4(d)(2)(vi)) as the relevant hydrogen production facility. The regional constraints proposed in the Draft Rules limit geographies to the Balancing Authority level, with the exception of MISO, which is split between MISO-Midwest and MISO-Delta. However, the GREET model uses the NERC boundaries, which are larger and broader regions, to calculate a clean hydrogen facility's CI based on that NERC region's grid CI.

Section IV(iii)(B): Issue

The current GREET model uses a grid emissions profile based on the NERC Regional Boundaries[17], which are very broad and do not accurately reflect the grid emissions imposed under the boundary rules as set by the Deliverability requirement. Under the deliverability requirement, the regional EAC boundaries are limited to the Balancing Authorities as identified in the DOE's Needs Study[18], with the exception of MISO. This difference between the regions used to set boundary limits and the regions used to influence grid emissions calculations will result in an imbalance for clean hydrogen facilities located in regions which have a higher grid emission profile (due to higher emitting forms of conventional energy generation) but are not in the grid system associated with that facility's actual electric load.

Section IV(iii)(C): Proposed Solution

The GREET model should match the DOE's Balancing Authority map to calculate regional grid emission profiles, thereby providing a better representation of actual grid emission profiles and the resulting CI scoring for clean hydrogen facilities that use grid power.

17 https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/Regions%20Map.jpg
18 4 US DOE. (2023). National Transmission Needs Study. National Transmission Needs Study (energy.gov)

IV(iv): Clean Hydrogen Operating Margin

Section IV(iv)(A): As Proposed via IRS:

Proposed § 1.45V–4(b) would provide procedures to calculate the lifecycle GHG emissions rate of hydrogen produced at a hydrogen production facility using the most recent GREET model as defined in proposed § 1.45V–1(a)(8)(ii) (referring to 45VH2–GREET). Proposed § 1.45V–4(b) would provide that for each taxable year during the period described in section 45V(a)(1), a taxpayer claiming the section 45V credit determines the lifecycle GHG emissions rate of hydrogen produced at a hydrogen production facility using the most recent GREET model. Such a determination is made separately for each hydrogen production facility the taxpayer owns and as of the close of each respective taxable year in which such production occurs (that is, such a determination is made for that taxable year's total hydrogen production at a hydrogen production facility). Proposed § 1.45V–4(b) would provide that in calculating the lifecycle GHG emissions rate for purposes of determining the amount of the section 45V credit, the taxpayer must accurately enter all information about its qualified clean hydrogen production facility requested within the interface of 45VH2–GREET in compliance with the most recent version of the Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2–GREET (GREET User Manual), which currently can be found at: www.energy.gov/45vresources. Current 45VH2–GREET, previous versions of 45VH2–GREET, and subsequent updates to 45VH2–GREET can be found at www.energy.gov/45vresources. Proposed § 1.45V–4(b) would provide that information for the location of 45VH2–GREET and accompanying documentation will be included in the instructions to the Form 7210, Clean Hydrogen Production Credit. Section 3.2 of the DOE's "Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2003"[19], summarizes the process for using the GREET model to calculate a clean hydrogen facility's annual carbon intensity based on the electricity used in the production of clean hydrogen. The electricity used for clean hydrogen is categorized into two main types, grid power and renewable power (using EACs), where the total annual clean hydrogen volume produced must match each electricity type used. Thus, in a facility which is connected to the grid and using EACs, there must be a volume balance between hydrogen produced via EACs and that produced vis grid power. Thus, the annual hydrogen production considered for IRA 45V credit is aggregated for a final CI under the Draft Rules.

Section IV(iv)(B): Issue

Under the current Draft Rules, using the guide for the GREET model, titled "Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2003"[20], there is no operational tolerance for a clean hydrogen facility to produce hydrogen which is not covered by the necessary EACs. Thus, a clean hydrogen facility, which is sourcing EACs and is connected to the grid, that unintentionally produces hydrogen without the corresponding EACs, would create an EAC shortfall situation and be penalized by its aggregate CI score (based on the product being supplied by grid and EAC matched power, as dictated in the current Draft Rules). This EAC shortfall situation would require the clean hydrogen facility to either try and buy EACs on the open market to cover the grid production, which is unlikely, or it would yield a higher aggregate CI score, which could be detrimental to its viability due to a lower 45V credit value. This situation is especially concerning under the current Draft Rules when hydrogen producers will be required to hourly match, as there is virtually no margin for error operating a clean hydrogen facility without the corresponding EACs, which as noted are only available post generation. Thus, a clean hydrogen producer

19 https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf
20 https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf

will have very little ability to react to instances where EACs (specifically wind and solar RECs) are not being generated as needed, which results in uncertainty for the level of 45V credit a facility can expect. This adds indelible risk due to the inability for a clean hydrogen producer to react to instantaneous changes in EAC generation, as noted in the previous Articles, coupled with typical EAC contracting structures (PPA and VPPA). Without some level of operational tolerance, whereby a clean hydrogen facility can account for small instances when it is operating via grid power without EACs, it will result in credit uncertainty which will cause difficulty for the nascent clean hydrogen economy to secure financing and equity investments for projects.

This intermittency of operation, which is demanded under the current Draft Rules, will have a detrimental effect for offtake of clean hydrogen due to end-users typically requiring a continuous, uninterrupted supply of hydrogen. The issue of intermittent hydrogen supply is a new and fatal feature of the clean hydrogen market and is not of a significant concern for grey hydrogen production methods since their feedstocks, natural gas and heat, are stable and not intermittent. This intermittency for clean hydrogen production will lead to fewer instances where clean hydrogen can seamlessly replace emitting, grey hydrogen without some intermediate storage mechanism (i.e. utility scale battery storage or very large volume clean hydrogen storage). This will be especially detrimental to the early clean hydrogen market as the commercial and economic viability of utility scale battery storage is prohibitive and large volume clean hydrogen storage is not possible in all regions or economically justifiable. These factors, without some level of operational tolerance, will ultimately restrict clean hydrogen market adoption and will concede industry to continue using emitting grey hydrogen, thus stifling decarbonization.

As noted above, without the Draft Rules incorporating a measure of operational tolerance, it will be extremely difficult for new clean hydrogen producers to offer a continuous supply of clean hydrogen to offtakers. This intermittent supply issue is driven by the nature of industrial and manufacturing processes, which require hydrogen in a relatively steady supply to operate safely and reliably. Thus, a clean hydrogen producer will need the ability to continue operating (rather than stop production) even when it doesn't have the associated EACs so it can provide seamless, uninterrupted hydrogen supply.

Sec. IV(iv)(C): Proposed Solution

The Draft Rules should include a provision for establishing an operational tolerance, whereby a clean hydrogen producer has a maximum percentage of its daily production it can operate outside its corresponding EAC profile without being penalized by an aggregate CI score (based on the combined production from EAC-matched and grid-supplied product as dictated in the current Draft Rules). This percentage should be set at a maximum of 20% of the total hydrogen production capacity for a qualifying clean hydrogen facility as to keep the CI of its aggregate production under that of a conventional emitting grey hydrogen production method[21]. The comparison between conventional Steam Methane Reformer (CI of 11 kgCO2e/kg Hydrogen) and Low Temperature Electrolysis (using a mix of electricity as 80% renewable and 20% grid), yields a CI improvement of at least 4.7 kgCO2e/kg of hydrogen, excluding the HICC grid which yields the same resulting CI of 11 kgCO2e/kg hydrogen. In this scenario, the clean hydrogen producer would forgo IRA 45V credit for the volumes it produces that do not have corresponding EACs, up to the maximum of total annual volume. Any additional volumes over 20% of the total facility capacity which were supplied by the grid, and not covered by EACs

[21] https://greet.anl.gov/files/smr_h2_2019

volumes, would be included in the weighted average CI for the facility, as calculated using the GREET model. The maximum operational tolerance of 20% could be reduced over time with the proliferation of renewable energy in all geographies and as EAC accounting and data capabilities expand for hourly matching. This operational tolerance is needed to enable clean hydrogen producers to continue to serve customers who require a continuous supply of hydrogen. Economically, given the lack of 45V credit for non-EAC matched production and the significant financial incentive to achieve higher production capacity factors with associated EACs (and thus obtain more 45V credits), this should drive the development of more renewables facilities in regions where the ability to achieve continuous EAC matched operations is (currently) limited.