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Internal Revenue Service
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Ben Franklin Station, Washington, D.C., 20044

Comments of the National Hydropower Association in Response to
Notice of Proposed Rulemaking
Section 45V – Credit for Production of Clean Hydrogen

The National Hydropower Association ("NHA") submits these comments to the Notice of Proposed Rulemaking for Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy. On December 26, 2023, the U.S. Department of Treasury ("Treasury") and the Internal Revenue Service ("IRS") issued a notice of proposed rulemaking and public hearing requesting comments with respect to tax credits ("Sec. 45V" or "Credit") for the production of clean hydrogen ("Proposed Rule")[1] results from the Inflation Reduction Act of 2022 ("IRA").[2]

The NHA is a non-profit national association dedicated to securing water power as a clean, carbon-free, renewable, and reliable energy source that provides power to an estimated 30 million Americans. The association's membership consists of more than 320 organizations, including public and investor-owned utilities, independent power producers, equipment manufacturers, and professional organizations that provide legal, environmental, and engineering services to the water power industry. NHA promotes innovation and investment in all water power technologies, including conventional hydropower, marine energy and hydrokinetic power systems, and pumped storage hydropower to integrate other clean power sources, such as hydrogen, wind, and solar.

The nation's existing water power infrastructure, combined with new project deployment opportunities, are critical resources for achieving the Administration's climate policy goals that underlie the IRA's clean energy tax package. Water power is a clean, flexible, and reliable energy source that supports an estimated 72,000 well-paying jobs across the United States.[3] The sector also generates more than 6 percent of the country's utility-scale electricity and nearly one third of all utility-scale renewable power. In addition, pumped storage, which is a long duration energy storage technology, provides the majority of energy storage generation capability on the grid. Also, hydropower facilities often serve multiple purposes. Hydropower facilities not only

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[1] 88 FR 89220.
[2] Public Law 117-169. August 16, 2022.
[3] U.S. Department of Energy, U.S. Hydropower Workforce: Challenges and Opportunities (October 2022). https://www.energy.gov/eere/water/articles/new-report-highlights-hydropower-industrys-demand-new-diverse-talent.

generate electricity, but provide flood control, irrigation, water supply, recreational opportunities, river transportation, etc. NHA has previously filed comments relating to Sec. 45V that would provide options for IRS and Treasury to properly attribute lifecycle greenhouse gas emissions.[4] NHA appreciates the opportunity to offer the following comments and concerns.

1) Executive Summary

Treasury and IRS in § 1.45V-4(d)(3) create limitations on producing Qualified Clean Hydrogen.[5] Those are incrementality, temporal ("hourly") matching, and deliverability ("Three Pillars"). NHA specifically requests that Treasury and IRS issue a Final Rule that does not discriminate between new and existing carbon-free resources. The only differentiating factor would be the lifecycle emissions factor analyzed in the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model ("GREET") model.[6] NHA also recommends that Treasury and IRS implement the Credit by tracking lifecycle emissions on an annual, not hourly matching basis.

Should Treasury and IRS maintain the Three Pillars in some form or function (specifically as it relates to incrementality and hourly matching), NHA provides a range of options to improve the implementation of the Credit. These recommendations are intended to ensure that Qualified Clean Hydrogen can be produced in enough quantities to meet the purposes of Sec. 45V, which is to assist in decarbonizing hard to decarbonize certain industrial sectors. Specifically, NHA recommends that production of Qualified Clean Hydrogen that occurs in states with enforceable 100% zero-emissions, carbon-free, or renewable energy goals or 100% reductions in greenhouse gas emissions from a baseline are exempted from the Three Pillars.

2) Comments Regarding Incrementality

NHA has serious reservations regarding the requirement that Qualified Clean Hydrogen Production Facilities[7] be placed in-service within 36 months from generation from electricity generation facilities that has commenced operations. NHA provides information regarding those concerns below.

a) Incrementality Comment 1: Incrementality is Incompatible with the IRA

At no point in the Proposed Rule does Treasury or IRS point to the statutory basis for requiring incrementality.[8] The Proposed Rule only discusses potential alternative pathways for limited

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[4] NHA has recommended that no matter the vintage (i.e., existing or new resources), Qualified Clean Hydrogen Production Facilities can use Power Purchase Agreements, Renewable Energy Credits, building hydrogen production co-located with a clean resource, etc. as contractual and physical pathways. These are common arrangements to benefit from other tax credits under § 45 and § 48. National Hydropower Association, "Comments of the National Hydropower Association on the Credits for Clean Hydrogen and Clean Fuel Production Notice (Notice 2022-58). December 8, 2022. At https://www.regulations.gov/comment/IRS-2022-0029-0181.
[5] § 45V(c)(2)(A)
[6] § 45(c)(1)
[7] § 45V(c)(3)
[8] *See* 88 FR 89229-89232.

exceptions to incrementality, while pointing to past Environmental Protection Agency ("EPA") precedent regarding induced grid emissions. That is because Congress never intended for an incrementality requirement to be included in the first place.

The Credit's value is dependent on the lifecycle greenhouse gas emissions to "…only include emissions *through the point of production (well-to-gate)* (emphasis added)…" as determined by the latest GREET model.[9] Meaning that the plain reading of the IRA is that the calculation is based off of the lifecycle emissions used to produce the Qualified Clean Hydrogen (including emissions from the electric system used to power hydrogen production), not the uncertain, downstream induced emissions that could occur due to exogenous changes occurring in the electric system. A taxpayer's[10] eligibility to produce hydrogen is not limited by vintage of the electricity generating facility, only by lifecycle emissions through the point of production to produce Qualified Clean Hydrogen.

Congress was also very intentional in its use of the word "any." Congress used the word "any" multiple times in the context of the Applicable Percentage regarding Qualified Clean Hydrogen production,[11] which is limited in value to those processes with a lifecycle emissions rate not greater than 4 kgCO2e/kWhe. A Qualified Clean Hydrogen Production Facility is one which is owned by a taxpayer, whose construction being before January 1, 2033, *which produces qualified clean hydrogen* (emphasis added).[12] Finally, the use of the word "any" is explicit in Congress' intent regarding the increased credit amount for the same Qualified Clean Hydrogen Production Facilities. In § 45V(e), *any* (emphasis added) Qualified Clean Hydrogen Production Facilities will receive the 5x multiplier so long as they follow those requirements such as prevailing wage requirements.

There is no ambiguity with respect to this Credit regarding incrementality. This is also true in Congress' calculation of budgetary impact. In analyzing the budget impact of repealing Sec. 45V, the Joint Committee on Taxation ("JCT") assumes for the purposes of calculating the budget impact of this Credit that Qualified Clean Hydrogen production can utilize existing carbon-free electricity generation.[13] JCT estimates $127M of credits would not be provided to taxpayers. It would be impossible for a new renewable resource to be paired with a new electrolyzer in the four months between Sec. 45V becoming effective and this analysis and produce that much Qualified Clean Hydrogen. This revenue impact had to be associated with Qualified Clean Hydrogen Production Facilities utilizing existing generation. If the score was only analyzing new resources, the revenue impact would be zero.

For the reasons above, Treasury and IRS should issue a Final Rule that allows for taxpayers to benefit from the Credit so long as the taxpayer owning the Qualified Clean Hydrogen

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[9] § 45(c)(1)(B)
[10] For the purposes of this document, when NHA refers to a taxpayer it also includes Applicable Entities eligible for Elective Pay under Section 6417 of the Internal Revenue Code.
[11] § 45(b)(2)(A)-(D)
[12] § 45(c)(3)
[13] HR 2811 score, JCX-7-23, at line 6 (April 26, 2023). Available at https://www.jct.gov/getattachment/1bd2fab7-1a0f-4c30-9a8f-94b98f3b2888/x-7-23.pdf.

Production Facility can prove that the Qualified Clean Hydrogen Facility has a lifecycle emissions rate provided for in §45V(b) that is indifferent to the commercial operations date of the electricity generating facility that is providing electricity to the Qualified Clean Hydrogen Production Facility.

b) Incrementality Comment 2: The Legal Justification Supporting Incrementality in the EPA Letter is Arbitrary and Capricious

As discussed above, the Proposed Rule did not provide a statutory basis for incrementality. It does, however, reference a letter from EPA's Deputy Administrator, Janet McCabe to Lily Batchelder, Assistant Secretary for Tax Policy at Treasury ("EPA Letter").[14] Treasury and IRS rely on past EPA precedent discussed in the EPA Letter to implement the Sec. 45V tax credit.[15] The EPA Letter cites to the Renewable Fuel Standard ("RFS2") rulemaking, promulgated as a result of enacting CAA 211(o)(1)(H), from 2010 as precedent.[16]

The Sec. 45V credit cross-references section 211(o)(1)(H) of the Clean Air Act ("CAA"),[17] with the caveat captured in subparagraph (B) that "…shall only include emissions through the point of production…" Therefore, Congress' intent was to utilize CAA 211(o)(1)(H) with a clearly defined qualification. Instead of analyzing direct emissions and significant indirect emissions relating to the full fuel cycle as discussed in CAA 211(o)(1)(H), the Credit is subject to the most recent GREET model. Even if, *arguendo*, Congress intended to wholesale adopt the language of CAA 211(o)(1)(H) for the Credit, then the analysis would analyze direct and indirect emissions in the context of "lifecycle greenhouse gas emissions". This would *not include induced emissions* (emphasis added), which EPA chose not analyze in the RFS2 rulemaking.[18]

Also, and ironically, in implementing the RFS2 program, EPA explicitly rejected differentiating between existing landfills and newly installed projects.[19] Like the discussion below on broader bulk electric system evolution and public policy objectives, EPA was right in not discriminating between new and existing projects because:

> …many of the new facilities may have installed gas-to-energy projects regardless of the [renewable fuels] program, driven by the same incentives that motivated the existing facilities. Given the existence of other incentives to install gas-to-energy capabilities, *discriminating between existing and new gas-to-energy projects seems arbitrary in this light* (emphasis added).[20]

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[14] At https://home.treasury.gov/system/files/136/45V-NPRM-EPA-letter.pdf.
[15] 88 FR 89227-89228
[16] 40 CFR Part 80. 59 FR 7716.
[17] § 45(c)(1)(A).
[18] EPA Letter at 4.
[19] Support for Classification of Biofuel Produced from Waste Derived Biogas as Cellulosic Biofuel and Summary of Lifecycle Analysis Assumptions and Calculations for Electricity Biofuel Produced from Waste Derived Biogas, EPA Air and Radiation Docket EPA-HQ-OAR-2012-0401, at p. 22 (July 1, 2014), available at https://www.regulations.gov/document/EPA-HQ-OAR-2012-0401-0243.
[20] *Id*.

EPA skirts the issue in the EPA Letter to state that despite all the evidence and precedent discussed above, EPA attempts to reinterpret indirect emissions as "induced grid emissions."[21] EPA's letter makes a number of inferences that fly in the face of precedent set by the RFS2 program and the clear distinction Congress made in limiting the reference to CAA 211(o)(1)(H) as lifecycle emissions through the point of production as defined by the GREET model. This deception is designed to support a predetermined outcome. Therefore, EPA's justification is arbitrary and capricious.[22]

c) *Incrementality Comment 3: Co-Located Loads Demonstrate that Incrementality was never Considered in the IRA*

One method that certain customers utilize is constructing a demand side resource behind-the-meter, or co-located, with a generation asset. Those resources could be a Qualified Clean Hydrogen Production Facility, a data center, or even a co-located electrical storage facility. The Proposed Rule contemplates this setup.[23] As electrolyzers are likely to be operated in a baseloaded fashion (i.e., 8,760 hours in a year) to maximize production, they would not materially impact grid emissions. Emissions changes are a result of variable changes occurring in the bulk electric system, not because of baseloaded system demands. This is because supply and demand on the system are always changing due to exogenous factors such as weather, economic booms and busts (that increase and decrease demand respectfully, *ceteris paribus*), etc., and endogenous factors such as capacity additions and retirements.

Basic logic would say that in such a situation, the Qualified Clean Hydrogen Production Facility that is co-located with an existing carbon-free generator would select that generator as the source input from the GREET model. At that point, the only consideration for the taxpayer is the lifecycle emissions factor associated with producing Qualified Clean Hydrogen, which would be 0 kgCO2e/kWhe if co-located with water power, wind, and solar energy sources.[24] However, but for incrementality, a Qualified Clean Hydrogen Production Facility could not benefit from this setup from an existing electricity generating facility or in a situation where there is a delay in placing in-service the Qualified Clean Hydrogen Production Facility beyond 36 months. With the incrementality requirement, a Qualified Clean Hydrogen Production

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[21] "Increased demand for electricity from electrolyzers for hydrogen production can result in indirect greenhouse-gas emissions. Specifically, adding new incremental electricity demand to the electric grid will often result in either increased generation from existing generators, with associated emissions, or new incremental capacity coming online. If the new incremental generation is not zero-emitting, it will also lead to increased systemwide greenhouse-gas emissions from the electric grid. *Such indirect emissions, sometimes referred to as 'induced grid emissions,'* (emphasis added) are an anticipated real-world impact of increased electricity demand due to electrolytic hydrogen production." EPA Letter at 4.

[22] "..[a] decision is arbitrary and capricious if the agency [1] has relied on factors which Congress has not intended it to consider, [2] entirely failed to consider an important aspect of the problem, [3] offered an explanation for its decision that runs counter to the evidence before the agency, or [4] [has offered an explanation] so implausible that it could not be ascribed to a difference in view or product of agency expertise." *George v. Bay Area Rapid Transit*, 577 F.3d 1005, 1010 (9th Cir. 2009)

[23] § 1.45V–4(d)(1)

[24] Energy. Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023. December 2023.

Facility would have to procure Energy Attribute Certificates ("EACs") from electricity generating facilities elsewhere on the grid *not* the facility whose meter it sits behind.

d) Incrementality Comment 4: The 36-Month Limitation is Arbitrary and Capricious

To limit the ability for Qualified Clean Hydrogen Production Facilities to benefit from the credit, Treasury and IRS limit applicability to hydrogen production in § 1.45V–4(d)(3)(i)(A) from new electricity generating resources that have been placed in service in the 36 months prior to the placed in-service date of the Qualified Clean Hydrogen Production Facility or through an uprate under § 1.45V-4(d)(3)(i)(B).[25] Nowhere in the Proposed Rule does the Treasury or IRS explain why this limitation exists. There is no explanation for this limitation in either the Department of Energy's ("Energy") *Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit* ("White Paper") or the EPA Letter for this 36-month limit either. This arbitrary limitation unduly discriminates against carbon-free electricity generating resources that might have been placed in-service just prior to the 36-month window, or those Qualified Clean Hydrogen Production Facilities that may have delays being placed in-service.

e) Incrementality Comment 5: Avoided Retirements cannot be Administered on a Unit-by-Unit Basis

IRS and Treasury ask several questions that attempt to "minimize the risk of significant induced grid emissions for certain existing electricity generating facilities."[26] One pathway Treasury and IRS request is input on an approach relating to avoided retirements.[27] As discussed below, there are numerous reasons why a resource might be retired such as public policy reasons. The decision to retire a resource is not one taken lightly by asset owners. One common situation is one of capital allocation. Rarely are retirements a simple profit and loss calculation but one of capital allocation. Take a company with a portfolio of assets (assets A, B, and C) and limited capital and an expected return on equity of 8%. The return on equity for assets A, B, C run 10%, 8%, 3% respectively (i.e., each asset is profitable by varying degrees). Since Asset C is underperforming, the asset owner may consider retirement of that asset especially if Asset C requires substantial capital investment. In such a situation, the Asset Owner may look to retire Asset C (or alternatively, divest Asset C to another entity).

This approach contemplates relicensing decisions as a decision point by which resources may be retired due to the capital requirement needed to relicense a facility. Although partly true, the timeframe may not work for water power assets. The IRA requires Qualified Clean Hydrogen Production Facility to have commenced construction prior to January 1, 2033 (less than 9 years from the comment deadline of this Proposed Rule). Generally speaking, the relicensing process

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[25] NHA notes that capacity additions for FERC-licensed water power facilities are found in the FERC license and should be justification for uprated capacity to serve Qualified Clean Hydrogen. 18 § 4.200-4.202.
[26] 88 FR 89230.
[27] *Id.*

for a water power facility can take on average 7.6 years with a standard deviation of 3.3 years.[28] This means that the owner of a Qualified Clean Hydrogen Production Facility would likely never be able to place its facility in service prior to January 1, 2033 if the taxpayer was looking to purchase EACs from a water power facility following relicensing.

NHA respectfully recommends that Treasury and IRS not consider an avoided retirements approach *on a unit-by-unit basis* (emphasis added) as it would be impossible to administer such an application in the context of the Sec. 45V credit. However, as discussed later, a potential alternative pathway is to allow for between 10-20% of a fleet's water power generation to be used by Qualified Clean Hydrogen Production Facilities in producing Qualified Clean Hydrogen.

f) *Incrementality Comment 6: Incrementality will Unjustly Impact the Water Power Industry and those Entities that Rely on Water Power for Electricity*

Water power in all its forms[29] has among the cleanest lifecycle emissions of any technology. According to Energy, water power, solar, and wind energy have a 0 kgCO2e/kWhe emissions factor.[30] But for the incrementality requirement, taxpayers that own a Qualified Clean Hydrogen Production Facility using existing electricity from existing water power facilities should be eligible for the full credit under § 45V(b)(2)(D). The calculation stemming from the most recent GREET model confirms a known fact that areas of the country that are predominantly and historically powered by water power have among the lowest emissions of any regions of the country. As shown in Table 1 below, the majority or plurality of Vermont, Washington, Idaho, Maine, and Oregon's generation is from water power. Table 2 shows emissions intensities by BA. Many BAs whose generation is predominantly water power heavy have incredibly low (such as BPA), or zero or effectively zero (such as numerous BAs in Washington state), emissions in their service territories.

Of the seven states with the lowest emissions intensity, five of them have their largest fuel share from water power. A sixth, South Dakota, has water power as its second largest fuel share. In rounding out the top 10 least emissions intensity states, New York and California have some of the highest amounts of generation from water power in the United States.[31] Only Montana and Alaska have water power as a top two electricity share, but are outside the top 10 cleanest grids, due to their large amounts of legacy fossil fueled electricity generation. Of these top 10 states, six (Vermont, Washington, Maine, Oregon, New York, and California) have enforceable goals for 100 percent carbon-free or renewable energy generation to serve load by varying dates. New

[28] National Renewable Energy Laboratory and Oak Ridge National Laboratory. An Examinatin of the Hydropower Licensing and Federal Authorization Process at Table 5. NREL/TP-6A20-79242. October 2021.
[29] Conventional hydropower (run-of-river and reservoir), pumped storage, marine, and hydrokinetic technologies.
[30] Energy. Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023. December 2023.
[31] EIA. Hydropower Explained: Where hydropower is generated. California and New York generate the second and fourth amount of water power in the United States from conventional hydropower. Accessed January 20, 2024 at https://www.eia.gov/energyexplained/hydropower/where-hydropower-is-generated.php.

Hampshire has an RPS of 25.2% by 2025 and New Jersey has an RPS goal of 50% by 2030. Idaho and South Dakota have no or expired standards.

Inadvertently, incrementality will negatively impact those regions that already have low carbon intensity as there is an existing base of carbon-free resources and state policies that will require all loads to be served by carbon-free or renewable generation. Incrementality would do nothing more than create administrative burden and incremental costs on ratepayers, including taxpayers producing Qualified Clean Hydrogen, while inhibiting the decarbonization of certain industries that hydrogen could enable.

g) *Incrementality Comment 7: An Incrementality Requirement Likely Violates the Major Questions Doctrine*

When an agency is not the expert in an area it seeks to promulgate a regulatory action and that action has "economic and political significant,"[32] the Supreme Court has struck down agency actions employing the Major Questions Doctrine.[33] Regarding the former point, Treasury and IRS are not experts in the vast number factors that influence electric sector emissions. In such a situation, IRS and Treasury "…must point to 'clear congressional authorization' for the power it claims" to use, which is the imposition of an incrementality requirement.[34] An agency can't simply point to "…something more than merely a plausible textual basis for the agency action…"[35] In this Proposed Rule, IRS and Treasury have not met that threshold to impose an incrementality requirement because they have not pointed to clear congressional authorization.

Where Congress has intended for an incrementality requirement, it has been clear in imposing such requirements. For example, § 45(c) lists several eligible technologies that are deemed to be qualified facilities.[36] Only one, qualified hydropower production under § 45(c)(8), have incremental requirements. Those requirements are very specific which require capacity and efficiency improvements that use the same water flow information and must be certified by the Federal Energy Regulatory Commission ("FERC").[37]

This is also true for the § 45Y credits that become effective for resources placed in-service after December 31, 2024. The credits under § 45 phase out on December 31, 2024 and are replaced by § 45Y technology neutral credits that are based off of incremental production through new units and additions in capacity.[38] Congress, in a related way, also requires these incremental resources to have a greenhouse gas emissions rate not greater than zero *in the production of*

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[32] *FDA v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 160 (2000).
[33] Congressional Research Service. The Major Questions Doctrine. Updated November 2, 2022 at https://crsreports.congress.gov/product/pdf/IF/IF12077.
[34] *West Virginia v. EPA*, 142 S. Ct. 2587, 2607–2608 (2022).
[35] *Id.*
[36] In fact, Congress had the opportunity to change this interpretation when it passed the IRA. However, instead, Congress simply placed removed the credit rate reduction and made hydropower equivalent to other renewables in credit value. IRA at 136 Stat. 1913.
[37] § 45(c)(8)(B). FERC has a list of facilities certified at https://www.ferc.gov/sites/default/files/2020-04/tax-credit.pdf.
[38] § 45Y(b)(1)(C)(i)-(ii).

electricity (emphasis added).[39] Although this treatment is slightly different than a lifecycle emissions calculation, it does demonstrate that when Congress desires for credit eligibility to be based off of incremental production *and* that factors in emissions rates, Congress is very capable in providing clear, statutory language to taxpayers, IRS, and Treasury.

Therefore, the precedent is clear. IRS and Treasury do not have the authority to set national energy policy regarding hydrogen production, where it has no expertise, by promulgating an incrementality requirement. IRS and Treasury should remove incrementality as a requirement in the Final Rule.

3) NHA Comments Regarding Hourly Matching and Merits Supporting the Three Pillars

As discussed above, NHA's primary issue with the Proposed Rule is with respect to incrementality. However, NHA believes that Treasury and IRS should require Qualified Hydrogen Production to be tracked with annual time matching, as opposed to hourly matching. NHA also raises specific concerns regarding the technical analyses performed by Energy and EPA that should be addressed by those agencies prior to issuing a Final Rule.

a) Hourly Matching is Arbitrary and Capricious and Challenging to Administer

The Proposed Rule would require taxpayers to use hourly matching[40] beginning January 1, 2028.[41] NHA would first note that hourly matching would be a generally new construct. IRS and Treasury recognize this in the Proposed Rule by correctly discussing many of the limitations for implementing an hourly matching requirement.[42]

Even if an agency's decision is less than clear, the Supreme Court has found that it will still uphold a decision if the "path can be reasonably discerned."[43] IRS and Treasury have provided significant evidence of limitations to hourly matching in the Proposed Rule to demonstrate that hourly matching should be scrapped in its entirety or, as recommended below, delayed for Qualified Clean Hydrogen Production Facilities that commence construction prior to 2032. Even in the most optimistic of scenarios, several requirements would need to perfectly align to ensure a transition to an hourly matching system. Many such requirements are not based in overcoming engineering and technical limitations, but in challenges regarding decision making by policy and regulatory bodies.[44]

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[39] § 45Y(b)(1)(A)(iii) that references § 45Y(b)(2)(A).
[40] § 1.45V–4(d)(3)(ii)(A)
[41] § 1.45V–4(d)(3)(ii)(B)
[42] 88 FR 89233. Among other limitations, the Proposed Rule discusses how not only is there infrastructure and software limitations but regulatory, cost, stakeholder engagement, and then end user limitations for transactions and tracking by users. These exist even for the minority of the tracking systems that are more readily prepared to implement an hourly matching requirement.
[43] *Bowman Transp. v. Arkansas-Best Freight Sys*., 419 U.S. 281, 286 (1974)
[44] *Id.* "…one gave a timeline of three to five years; in the latter case, the respondent noted that the timeline *could* [emphasis added] be closer to three years *if there is full state agency buy-in, clear instructions are received from federal or state agencies, and funding for stakeholder participation is made available* [emphasis added]."

Using an annual matching requirement would also align with precedent from other time matching requirements for other energy credits.[45] In the case of dual use of geothermal equipment[46] and certain auxiliary equipment for solar energy property,[47] IRS and Treasury has adopted an "annual measuring period" for an item of dual use equipment as the 365 day period beginning with the day it is placed in service or a 365 day period beginning the day after the last day of the immediately preceding annual measuring period. NHA recommends similar rules for the implementation of the Sec. 45V credit.

b) *Technical Comments on Energy's Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit and Environmental Protection Agency's December 20 Letter*

At a high level, EACs are one reasonable contractual pathway to ensure compliance with the tax code. However, only if the rule surrounding their use is properly implemented will the hydrogen industry take off in such a way where certain sectors can be decarbonized. However, to support the use of incremental generation, geographic matching, and temporal matching, IRS and Treasury utilized the White Paper[48] and the EPA Letter.[49] The White Paper does explain some of the nuances of changes in load and supply as it relates to induced emissions, however the White Paper misses very elementary facts of the operation and planning of the bulk electrical system. The EPA Letter has even less nuance. NHA recommends that in reviewing comments, IRS and Treasury ensure that these facts discussed below are incorporated in any revisions promulgated in the Final Rule.

i) <u>Assertion 1: The White Paper and EPA Letter assumes that increased load from hydrogen production would automatically equate to increased emissions.</u>

Section 2 of the White Paper demonstrates that changes in load and supply on a second-by-second basis in day-ahead and real-time can have material impacts on emissions. It also explains, in succinct, yet generally correct detail how this dynamic can change over a planning horizon of years.[50]

Shockingly, Energy completely ignores the nuanced discussion in Section 2 and moves to statements that are designed to support a predetermined outcome in Section 3. Energy assumes that "without the three specific criteria for EAC attributes, EAC purchases associated with new hydrogen load *will not* (emphasis added) reflect important ways in which added loads can impact grid GHG emissions under a lifecycle framework."[51] The EPA Letter has even less

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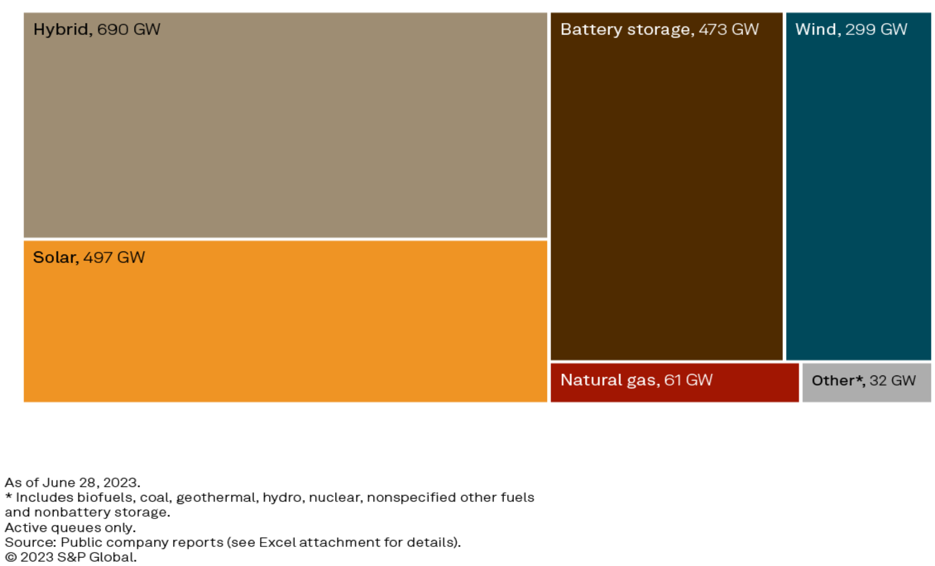
[45] § 1.48-9(d)(6)
[46] §1.48-9(c)(10)(iv)
[47] §1.48-9(d)(6)
[48] White Paper accessed at https://www.energy.gov/sites/default/files/2023-12/Assessing_Lifecycle_Greenhouse_Gas_Emissions_Associated_with_Electricity_Use_for_the_Section_45V_Clean_Hydrogen_Production_Tax_Credit.pdf/.
[49] At https://home.treasury.gov/system/files/136/45V-NPRM-EPA-letter.pdf.
[50] EPA Letter at 5-6.
[51] *Id* at 8.

nuance. The EPA letter simply ignores the complex relationships of how supply and demand change over time and wrongly assumes that the "…linkage between increased electricity demand from grid-connected electrolyzers and greenhouse-gas emissions induced by that demand *does not appear to be extended or overly complex* (emphasis added)."[52]

The assertions made in the White Paper and EPA Letter are designed to support a desired outcome that is divorced from the practical reality of today's electricity system.

First, at no point in the Proposed Rule, White Paper, or EPA Letter are there considerations for the fact that the interconnection queues in the United States are full of carbon-free resources. The Proposed Rule creates the Three Pillars because of concern for downstream induced emissions.[53] Specifically, there is a concern that increased hydrogen production will increase fossil fuel usage on the grid from existing fossil resources and new fossil resources being brought online. However, as demonstrated in the image below, the interconnection queues in the United States are ***94.4%*** renewable resources as of summer 2023.[54] Also, 473 GWs of that capacity is dispatchable resources such as battery storage and an additional 690 GWs are hybrid (i.e., battery storage co-located with another renewable technology, predominantly solar). These GWs add up to more than double the amount of natural gas fired generation capacity in the United States.[55]



52 EPA Letter at 3.
53 The EPA Letter is used as legal justification to support the concept that induced emissions from new hydrogen production are "significant indirect emissions" under its interpretation of Clean Air Act section 211(o)(1)(H).
54 S&P Global. US Interconnection Queues Analysis 2023. Accessed on January 20, 2024 at https://www.spglobal.com/marketintelligence/en/news-insights/research/us-interconnection-queues-analysis-2023.
55 U.S. Energy Information Administration ("EIA"). U.S. Electricity Generating Capacity by Major Energy Source, 2022 shows that there is 497 million kilowatts (equivalent to 497 Gigawatts). Accessed on January 20, 2024 at https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.

Second, the Proposed Rule, White Paper, or EPA Letter do not consider greater forces impacting retirements of legacy fossil fuel resources. In 2023, ***98.2%*** of retirements were from coal, natural gas, and oil-fired power stations.[56] Approximately a quarter of coal-fired capacity is expected to retire by the end of the decade.[57] Retirements of conventional resources have become so common place that the Chief Executive Officer of the North America Electric Reliability Corporation ("NERC"), who develops and oversees Reliability Standards of the bulk electric system, has raised concerns regarding the future reliability of the electric system.[58] These retirements can occur for a number of reasons such as economics and public policy choices.[59] These retirements are not limited to states with Renewable Portfolio Standards ("RPS") or other similar policies as well.[60]

Third, the Federal Power Act ("FPA") is the primary statute governing wholesale transmission and sale of electric power in the United States.[61] The jurisdiction over interstate rates and wholesale sales of electricity falls underneath the FERC. The FPA, however, reserves significant authority for states in the choices of electricity generation within their boundaries so long as those decisions don't "…intrude on FERC's authority over interstate wholesale rates…"[62] States routinely take advantage of this authority to pass laws and promulgate regulations that require clean generation to be either maintained or built to serve customers. In fact, thirty states and Washington, D.C. have active renewable or clean energy requirements. Three more have set voluntary standards. Many states plus Washington, D.C. have 100% requirements for renewable or carbon free generation to serve load in their territories.[63]

The Proposed Rule wrongfully assumes that each increment of load from hydrogen production will increase emissions. This not only ignores the nuances of how the grid is operated today, but it is also shortsighted and fails to recognize that any potential increase in emissions would be short lived due to the impending retirement of fossil fuel resources and influx of renewable

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[56] EIA. Today in Energy: Coal and Natural Gas Plants will Account for 98% of U.S. Capacity Retirements in 2023. February 7, 2023 at https://www.eia.gov/todayinenergy/detail.php?id=55439.
[57] EIA. Nearly a Quarter of the Operating U.S. Coal-Fired Fleet Scheduled to Retire by 2029. November 7, 2022 at https://www.eia.gov/todayinenergy/detail.php?id=54559.
[58] Written Testimony of James B. Robb, President and Chief Executive Officer, North American Electric Reliability Corporation Before the Committee on Energy and Natural Resources. June 1, 2023.
[59] "Planned retirements continue to be focused on relatively older facilities. Coal-fired generators—especially older, less efficient units—face higher operating and maintenance costs, which make them less competitive and more likely to retire. In addition, some coal-fired power plants must comply with regulations limiting the discharge of wastewater by 2028, which would require additional capital investment, likely influencing the decision to retire some of these coal-fired units." EIA. Nearly a Quarter of the Operating U.S. Coal-Fired Fleet Scheduled to Retire by 2029. November 7, 2022 at https://www.eia.gov/todayinenergy/detail.php?id=54559.
[60] *Id. "*Michigan, Texas, Indiana, and Tennessee have the most coal-fired capacity announced to retire through 2029, accounting for a combined 42%."
[61] 16 USC §§ 791.
[62] *Hughes v. Talen Energy Mktg*., 136 S. Ct. 1288 (2016).
[63] National Conference of States Legislatures. Navigating the Energy Transition: A Review of State Policies. Accessed January 21, 2024 at https://www.ncsl.org/energy/energy-transition-report.

resources across the United States and particularly in states with renewable or clean energy goals.

ii) Assertion 2: Electricity cannot be reasonably tracked between regions.

Not only are the Proposed Rule, White Paper, and EPA Letter concerned about additional loads from hydrogen production creating induced emissions from a change in operation at fossil fired power stations or from a capacity standpoint, Treasury, IRS, EPA, and Energy are concerned about a common industry term called "leakage." Leakage, generally, means that imposing limitations in one region could create increased emissions in another that does not have such limitations. The White Paper falsely portrays that generation from one state cannot meet load in another state that could be a significant distance away.[64] Although it is true that each Balancing Authority ("BA") is required to carry a certain amount of generation within its boundaries to maintain system frequency and control due to NERC requirements,[65] it is flatly incorrect that a generator in a neighboring or distant BA ("source") cannot serve load in another BA ("sink"). These transfers are overseen by Reliability Coordinators ("RCs").

Following the Energy Policy Act of 1992[66] and FERC Orders 888 and 889,[67] a software system called Open Access Same-Time Information System ("OASIS") was created. OASIS allows for sources to reserve transmission across seams between BAs (called E-Tags or "Tags") such that the energy arrives to the sink. Tagging MWs are subject to federal requirements from NERC and overseen by RCs.[68] To use Energy's example in the White Paper,[69] if there's an extreme weather event that disrupts electricity generation in Florida, a generator in Montana could reserve transmission across BAs in the Eastern Interconnect to serve load in Florida (and vice versa). Tagging MWs between source and sinks are an everyday occurrence across the electric power sector typically due to arbitrage opportunities between BAs.

In fact, because OASIS exists, some entities such as California's largest BA, the California Independent System Operator ("CAISO"), require imports into its BA to be tagged, with an associated emissions rate, or else those MWs will be assigned an emissions rate equivalent to a combined cycle power plant.[70] Under California's cap-and-trade program, each generator is provided a limited volume of allowances. For importers, those allowances are surrendered depending on the emissions rate. The practical effect is that carbon-free resources have a

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[64] "…an electricity generator located in Florida is not able to meet load in Montana." White Paper at 5.
[65] NERC Standard BAL-001 and BAL-005.
[66] Public Law 102-486. October 24, 1992.
[67] Order 888: Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. 61 FR 21540 (May 10, 1996). Order 889: Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct. 61 FR 21737 (issued May 10, 1996).
[68] NERC Standard INT-001 – Interchange Transaction Tagging.
[69] White Paper at 5.
[70] This is a result of Assembly Bill 32: Global Warming Solutions Act of 2006 which directs the California Air Resources Board to adopt regulations to reduce emissions.

competitive advantage over those with a higher emissions rate both inside and outside of CAISO.

Washington is another example. Washington has many BAs and load serving entities, that are also investor-owned utilities, public utility districts ("PUDs"), etc., nested within the multi-state Bonneville Power Administration ("BPA") BA. Washington's Clean Energy Transformation Act ("CETA")[71] requires utilities to eliminate coal-fired generation from serving its customers by 2025, to become greenhouse gas neutral by 2030, and by 2045 to generate 100% of their power from renewable or carbon-free resources. As it specifically relates to the CETA, the elimination of coal-fired generation is not only for generation internal to Washington, but also includes imported generation. Washington's load serving entities must now ensure that imported MWs come from non-coal resources by 2025, or else pay a fine of $150/MWh. This is nearly double the weighted average Mid-Columbia On-Peak trading price in 2023 of $88.56/MWh.[72] The requirements in CETA placed upon load serving entities in 2030 and 2045 also extend to imported generation. Therefore, utilities must ensure that MWs imported into their service territories come from specific types of generation or else they will pay alternative compliance penalties.

Theoretically, leakage is a reasonable concern. However, between existing constructs such as tagging MWs through OASIS, state public policies, etc., electricity transfers between regions can be tracked with reasonable certainty mitigating the concerns regarding leakage.

c) Curtailments are not always an Economic Decision

The Proposed Rule considers pathways for existing clean energy generation that would allow a portion of curtailed energy to be credited in such a manner that a taxpayer could qualify for Sec. 45V.[73] NHA provides specific feedback, including on the formulaic approach later in these comments.

Although the Proposed Rule is correct that there are instances where renewable resources, specifically weather-dependent zero cost resources such as wind and solar, will curtail their output when locational marginal price ("LMPs") drop below $0/MWh or below the negative value of their Renewable Energy Credits ("RECs").[74] Fundamentally this is true, but is so incomplete that it fails to understand the realities of operating the electric system.

NHA would also note that curtailments are an economic inefficiency that BAs attempt to mitigate. One method is to improve transmission to enable generators to serve load across a larger geographic area. Another method is ensuring through market rules and tariffs that limits

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[71] SB 5116 – Effective May 7, 2019.
[72] EIA. Wholesale Electricity and Natural Gas Market Data. Accessed on January 20, 2024 at https://www.eia.gov/electricity/wholesale/#history.
[73] 88 FR 89230-89232.
[74] In this situation, if a wind facility has a REC value of $45/MWh, then the economic decision to curtail would not occur until -$44.99/MWh.

are placed on renewable generators that mitigate the need for real-time curtailments by properly managing congestion.

i) Alternative Reason 1: Curtailments for System Reliability

The bulk electric system is, in a nutshell, one large, human-engineered, machine connected by wires. If any of those wires become overloaded due to any number of situations (i.e., unplanned and planned transmission outages, unplanned and planned generator outage, missed load forecast by the grid operator, unplanned weather, etc.) then generators of any type can be dispatched or curtailed downwards.

BAs plan for this in numerous ways. For example, ISO-NE has planned the system in New England such that the single source contingency based on interregional limits that max out at 1,200 MWs. In certain situations, the few generators larger than 1,200 MWs will be curtailed down due to outages elsewhere in the New England and New York BAs.[75] This procedure is designed to protect for the loss of the 2,000 MW Phase II import line from Canada to New England.[76] As required by NERC standards, this procedure limits potential cascading effects that could compromise the broader Eastern Interconnect.[77]

ii) Alternative Reason 2: Spilled Water from Water Power Facilities

The Proposed Rule does consider how existing water power facilities could benefit by limiting spilled water.[78] The Proposed Rule discusses this in the context of economics, which again, is partly true. Water power facilities could spill water as required by dispatch from the BA, due to economics, recreation, ensuring water supply, or due to high inflows that challenge the turbine capacity. Commonly, however, water power operators spill water for environmental reasons. Specifically, water is spilled to ensure the health of fish populations. Because each waterbody is different and each water power facility operates differently within that water body, spilled water can be significant. For example, the Dalles Dam on the Columbia River can spill on average 40% of daily inflows over the spill season months which last from April to August.[79] This spilled water is accounted for via conditions agreed upon amongst stakeholders in constructs

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[75] Southern New England's largest unit, Millstone Power Station Unit 3, has a rated capacity greater than 1,200 MWs. However, in certain operating conditions on the broader transmission system, the unit can be curtailed down from 1,260 MWs to 1,200. This curtailment only occurs when there's unplanned or maintenance outages elsewhere on the system, not due to potential negative pricing. See Dominion Nuclear Connecticut, Inc. Millstone Power Station Units 2 and 3 License Amendment Request for Removal of Severe Line Outage Detection from the Offsite Power System. Accessed January 20, 2024 at https://www.nrc.gov/docs/ML1518/ML15183A022.pdf.

[76] ISO New England Inc. Transmission, Markets and Services Tariff: Attachment G – Procedure to Protect for the Loss of Phase II Imports. August 30, 2010.

[77] NERC Bal-001. System operators position the system so that at any given moment there are reserves available to cover 100% of the single largest contingency, and 50% of the next largest contingency.

[78] 88 FR 89231

[79] EIA. Columbia River Electric Generation in 2018 Remains Normal Despite Above-Normal Water Flow. September 28, 2018. At https://www.eia.gov/todayinenergy/detail.php?id=37152.

such as a Fish Passage Plan at a US Army Corps of Engineers Facility (like the Dalles Dam) or in a FERC license.

4) Comments on Recommendations to be Included in The Final Rule

As mentioned above, NHA recommends to Treasury and IRS remove incrementality requirements and move to an annual matching requirement in the Final Rule. These changes would be most consistent with Congressional intent. However, if Treasury and IRS continues to implement all the Three Pillars in some form or function, NHA recommends the following menu of changes to the Final Rule that would allow Qualified Clean Hydrogen Production Facilities to take advantage of the value proposition of existing water power facilities. As discussed in greater detail below, NHA would recommend:

- Exempt Qualified Clean Hydrogen Production in states with enforceable carbon reduction goals from the Three Pillars.
- Treasury and IRS should grandfather first-of-a-kind projects from the Three Pillars.
- Incrementality and hourly matching for existing carbon free resources should not be implemented until 2032.
- The commercial operations date for electric generators should be inclusive of those repowered under the 80/20 Rule.
- Taxpayers producing Qualified Clean Hydrogen should be able to procure 10-20% of existing carbon-free resources output across a company or fleet's portfolio.
- Power purchase agreements and co-located loads from existing electricity generating facilities are acceptable contractual pathways.

a) Recommendation 1: Allow for Qualified Clean Hydrogen Production in States with Enforceable Carbon Reduction Goals

Specifically, NHA recommends that Qualified Clean Hydrogen Production Facilities that are placed in-service in states with enforceable 100% zero-emissions, carbon-free, or renewable energy goals or 100% reductions in greenhouse gas emissions from a baseline are exempted from the Three Pillars. As discussed above, certain states have implemented enforceable and trackable emissions goals that require load serving entities to serve load using increasingly carbon-free or renewable energy. The Three Pillars, as currently contemplated, would add unnecessary administrative, duplicative, and costly burden to Qualified Clean Hydrogen Production Facilities in those states. In this situation it would be up to the taxpayer (i.e., the owner of the Qualified Clean Hydrogen Production Facility) to claim the credit and provide the necessary evidentiary support where needed. Annually, the Secretary of Treasury could certify which States have the necessary enforceable laws and regulations for this provision, as the information is publicly available.

NHA recommends that Treasury and IRS in any Final Rule exempt Qualified Clean Hydrogen Production Facilities from the Three Pillars in states with strict enforceable carbon-free and renewable procurement requirements. At minimum, these facilities should be exempted from incrementality requirements and to be allowed to track with annual matching through the life of the Credit.

b) Recommendation 2: Treasury and IRS Should Grandfather First-of-a-Kind Projects

The Three Pillars would arbitrarily and capriciously impact first mover projects. First-of-a-kind projects by their very nature tend to have higher risks than Nth-of-a-kind projects. These projects are being contemplated for numerous reasons, including investments made by the federal government into the Hydrogen Hubs.[80] The Hydrogen Hubs whose carbon intensity are the lowest would, perversely, be negatively impacted the most as there would now be extra requirements to procure clean energy on top of existing clean energy technologies.[81] Therefore, early mover projects associated with the Hydrogen Hubs that have commenced construction prior to January 1, 2033 should be grandfathered from the Three Pillars through the life of the Credit.

c) Recommendation 3: Incrementality and Hourly Matching for Existing Carbon-Free Resources Should Not Be Implemented until 2032

As mentioned, existing carbon-free resources like water power and nuclear have a large role to play in the scaling up of this nascent industry. To establish investment certainty, Qualified Clean Hydrogen Production Facilities whose construction commences prior to January 1, 2032 that utilize existing carbon-free resources should be grandfathered from incrementality or hourly matching. This is a reasonable date for water power as it can take between 7-8 years to relicense a water power facility, which is a typical time to replace turbines, generators, and other equipment that would incrementally increase generation.[82] From there, installing the new equipment at the water power facility and constructing and placing into service a Qualified Clean Hydrogen Production Facility would also need to occur. This would also provide time for EAC tracking systems to implement hourly tracking of EACs.

d) Recommendation 4: The Commercial Operations Date for Electric Generators should be Inclusive of those Repowered under the 80/20 Rule

In the Proposed Rule, § 1.45V–4(d)(2)(i) would define the "commercial operations date" by which the electricity generator begins commercial operations.[83] The commercial operations date is important as it starts the clock by which Qualified Clean Hydrogen Production Facilities have 36 months to be placed into service to qualify its production under Sec. 45V. The Proposed Rule does not mention electricity generation facilities whose owners have repowered their

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[80] https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations
[81] *Id.* For example, the Pacific Northwest Hydrogen Hub seeks to use existing hydropower to power electrolysis to decarbonize certain legacy sectors such as freight, agriculture, certain industries like refineries, and seaports. The hub would be predominantly located in Washington and Oregon, which have strict and enforceable carbon reduction goals. They will also be located in the BPA BA, which already has incredibly low carbon intensity.
[82] National Renewable Energy Laboratory and Oak Ridge National Laboratory. An Examinatin of the Hydropower Licensing and Federal Authorization Process at Table 5. NREL/TP-6A20-79242. October 2021.
[83] 88 FR 89248.

qualified facilities or energy property under the 80/20 Rule.[84] The Final Rule should include those electric generating resources that are originally placed in-service due to repowering under the 80/20 Rule. Under Sections 45 and 48, certain eligible technologies (many of which have 0 kgCO2e/kWhe emissions factor) could be used to power Qualified Clean Hydrogen Production Facilities. Starting January 1, 2025, to be eligible for Sections 45Y and 48E, qualified facilities will be required to have a greenhouse gas emissions rate no greater than 0 gCO2e/kWhe.[85] Therefore, Qualified Clean Hydrogen Production Facilities can utilize that electricity production if the incrementality requirement is retained by purchasing and retiring EACs from those resources that repower under the 80/20 Rule.

NHA notes that this would ensure alignment with the Green Power Partnership ("GPP") referenced in the EPA Letter. The GPP is a voluntary program that *inter alia* requires incremental renewable generation to be procured to qualify. Such eligible resources include resources that have repowered under the 80/20 Rule.[86]

NHA would also note, however, that water power projects need clarification on what property is integral to the generation of electricity (i.e., a unit of energy property) and what is real property (i.e., integral property) for the purposes of utilizing the 80/20 Rule.[87]

e) Recommendation 5: Formulaic Approaches to Addressing Incrementality from Existing Clean Generators

This Proposed Rule offers an alternative that would carve out 5% of generation from existing carbon-free generators as satisfying the incrementality requirement, while retaining hourly matching and deliverability requirements. Treasury and IRS' justification is that on average 5% of hours have negative prices which incent curtailment and that 5% of the nuclear fleet is at risk of retirement.[88] As discussed above, NHA provided general feedback above on why curtailments can occur which would increase the number of hours curtailments occur even if LMP is not negative. For those reasons and those discussed below, NHA would recommend that if Treasury and IRS create this alternative pathway that at a carveout between 10 and 20% carveout on a portfolio or fleet basis would be necessary for the reasons discussed below.

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[84] Notice 2018-59; see also, Rev. Rul. 94-31, 1994-1 C.B. 16; Notice 2008-60, 2008-2 C.B. 178; Notice 2016-31, §6.01, 2016-23 I.R.B. 1025; Notice 2017-4, §5, 2017-3 I.R.B. 541; Section 48 NOPR, § 1.48-14(a).
[85] § 45Y(b)(1)(iii) and § 48E(b)(3)(iii). Although not exactly equivalent to a lifecycle emissions factor as required under § 45V(c)(1), many technologies with a 0 kgCO2e/kWhe emissions factor, will be eligible qualified facilities under § 45Y and § 48E.
[86] *See* EPA's Green Power Partnership: Partnership Requirements. Updated May 2019. At 8-9. At https://www.epa.gov/sites/default/files/2016-01/documents/gpp_partnership_reqs.pdf.
[87] NHA. Supplemental Comments of the National Hydropower Association on Certain Energy Generation Incentives (Notice 2022-49), specifically relating to the 80/20 Rule and its Application to Inflation Reduction Act Clean Energy Tax Credits Referenced in Notice 2022-49. At https://www.regulations.gov/comment/IRS-2022-0023-2187. Comments of the National Hydropower Association in Response to Notice of Proposed Rulemaking – Section 48 – Definition of Energy Property and Rules Applicable to the Energy Credit. At https://www.regulations.gov/comment/IRS-2023-0054-0109.
[88] 88 FR 29231-29232.

NHA recommends Treasury and IRS, in a Final Rule, consider retirement for water power like it does for nuclear power in the Proposed Rule. As a rule of thumb, approximately half of the water power fleet is owned by the federal government and therefore not regulated by FERC. Approximately forty percent of the FERC-regulated, non-federal hydropower fleet (approximately 21 GWs of the 55 GWs of FERC-regulated water power) is up for relicensing through 2033. This equates to approximately 20% of the existing water power fleet by capacity, which includes the federal owned fleet.

A carveout of 5% on a unit-by-unit basis would be limiting for the water power industry. The 5% carve out would not benefit individual small water power facilities,[89] which constitute 89% of existing water power facilities.[90] If the typical electrolyzer is assumed to be 1 MW,[91] this means that any Qualified Clean Hydrogen could not be produced via electricity generation from water power facilities smaller than 20 MWs. Also, smaller water power facilities are more likely to be retired due to the lack of economies of scale and high fixed costs of relicensing. Therefore, a 5% alternative pathway would discriminate against small water power compared to other existing carbon-free technologies.[92]

Also, water power facilities are bid into the market and operated in numerous ways. In some circumstances, they are one-off facilities owned by a single operator (which is common in other carbon-free technologies, specifically nuclear) that could exist in a broader portfolio of facilities with many different fuel types. In many cases, they're part of an investor-owned utility, independent power producer, or public power utility where the water power resources exist on a basin and the operations need to be coordinated with water flows, environmental requirements, and system and load needs. As shown below in Table 2, numerous entities that are primarily powered by water power already have zero- or near-zero emissions rates (e.g., PUD No. 1 of Chelan County, PUD No. 1 of Douglas County, City of Tacoma, Seattle City Light, etc.). These entities operate their water power fleet in such a way that properly balances the numerous considerations for running a hydroelectric fleet (e.g., flow requirements, system dispatch, non-generation conditions in a license, etc.).

Therefore, for the reasons stated above, NHA recommends a 10-20% allowance as for minimal-emitting generators no matter the technology and on a portfolio or fleet basis if the Three Pillars are maintained in some form or function.

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89 Small hydropower is generally accepted to be 30 MWs or less in size.

90 https://www.hydro.org/policy/technology/small-hydro/

91 *See* Executive Summary which states that a typical electrolyzer is 1 MW. IRENA, Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal (2020). International Renewable Energy Agency, Abu Dhabi.

92 The average nuclear plant, for example, is nearly 1,000 MWs. This would allow an alternative pathway of nearly 50 MWs of Qualified Clean Hydrogen Production.

f) Recommendation 6: Power Purchase Agreements and Co-Located Loads from Existing Electricity Generating Facilities are Acceptable Contractual Pathways

The Proposed Rule would require geographic matching to occur by requiring EACs to be purchased and retired in regions equivalent to the those provided in an Energy National Transmission Needs Study (Energy Study).[93] NHA believes this is generally reasonable as it nearly equates to regions that have EAC tracking systems. If the Qualified Clean Hydrogen Production Facility is being produced in a region that has a tracking system, EACs should suffice as one contractual pathway. However, in certain regions of the country these tracking systems do not exist.[94] In such situations, alternative contractual pathways are needed such as a Power Purchase Agreement ("PPA") and co-locating Qualified Clean Hydrogen Production Facilities with electricity generating facilities. PPAs and co-locating loads are very common methods for customers to ensure their electricity generation is provided by carbon-free or renewable energy sources and should be acceptable pathways whereby the Qualified Clean Hydrogen Production Facilities would select that generator or portfolio of generators as the source input to be cross referenced with the GREET model.

PPAs could be physical or virtual/financial. Physical PPAs would be the supply of energy through existing wires and the customer receives the title to the energy. Co-located loads would be similar in nature as the physical delivery of electricity occurs behind-the-meter of the electricity generating facility. Virtual or financial PPAs appear to be included in the Proposed Rule. This would allow a customer to purchase the renewable attributes (i.e., RECs) of an electricity generating facility while not necessarily receiving the physical delivery of the electricity or the title to that electricity. NHA believes clarifying this point is needed, no matter the region of the country.

5) Conclusion

The Sec. 45V credit has much promise to boost a nascent industry that could decarbonize certain industrial sectors. However, this credit will only be as useful as the rules that govern its applicability. NHA recommends that Treasury and IRS remove incrementality as a requirement for producing Qualified Clean Hydrogen and that annual matching be utilized. However, if Treasury and IRS maintain the Three Pillars, NHA offers a suite of recommendations that would allow carbon-free, reliable water power to be utilized to scale up this burgeoning industry that is meant to decarbonize hard to abate industrial sectors. NHA appreciates the opportunity to comment and looks forward to discussing with Treasury and IRS as appropriate.

[93] Energy. National Transmission Needs Study, Oct. 2023, available at https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf.

[94] Specifically areas of the Midwest, southeast, Alaska, and Hawaii. EPA. Renewable Energy Tracking Systems. Accessed on February 17, 2024 at https://www.epa.gov/green-power-markets/renewable-energy-tracking-systems#contract.

Sincerely,

*/s/ Michael Purdie*______

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Table 1			
2021	**Emissions Intensity lbs/MWh**[95]	**Water Power Percent Share of In-state Generation**[96]	**Water Power Rank as Fuel Share**
Vermont	36.045	50	1
Washington	201.827	64.6	1
Idaho	271.34	51	1
Maine	301.041	27.1	1
South Dakota	302.919	29.7	2
New Hampshire	304.042	6.7	3
Oregon	325.804	46.4	1
New York	455.345	22	3
California	479.005	7.2	5
New Jersey	480.917	0	7
Connecticut	515.143	0.7	4
South Carolina	567.026	3	4
Virginia	599.211	0.8	6
District of Columbia	651.672	0	4
Illinois	653.049	0.1	7
North Carolina	669.484	5.8	5
Maryland	698.189	5.3	4
Tennessee	698.276	15.1	4
Nevada	715.075	4.7	5
Arizona	724.809	5.4	5
Pennsylvania	726.431	0.8	6
Alabama	750.8	8.8	4
Oklahoma	753.545	3.3	4
Georgia	758.082	3.2	6
Iowa	768.928	1.4	4
Minnesota	825.973	1.5	7
Louisiana	826.042	1.2	6
Rhode Island	832.723	0.1	5
Mississippi	833.952	0	6
Florida	834.138	0.1	7
Kansas	838.186	0.1	6
Massachusetts	851.43	2	4
Texas	856.438	0.2	7
Delaware	867.498	0	7
Alaska	920.015	27.7	2
Michigan	1,003.76	0.7	7
Montana	1,045.02	40	2
Arkansas	1,086.93	7.3	4

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[95] EPA. 2023. "Emissions & Generation Resource Integrated Database (eGRID), 2021" Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's eGRID web site: https://www.epa.gov/egrid.

[96] EIA. EIA-923 Power Plant Operations Report for 2021. Accessed January 20, 2024 at https://www.eia.gov/electricity/data/state/.

Nebraska	1,124.84	3.3	5
New Mexico	1,134.31	0.5	5
Ohio	1,208.18	0.3	8
Colorado	1,216.92	2.8	5
Wisconsin	1,267.12	3.8	4
North Dakota	1,340.69	5.2	3
Hawaii	1,490.97	1.2	7
Utah	1,560.50	1.8	5
Indiana	1,632.59	0.3	6
Missouri	1,636.06	2.4	5
Kentucky	1,727.09	7.5	3
Wyoming	1,833.92	2.3	4
West Virginia	1,944.15	2.3	4

Table 2					
BA Emissions Intensity in lbs/MWh[97]	**2021**	**2020**	**2019**	**2018**	**Average**
Alcoa Power Generating, Inc. - Yadkin Division	0.0	0.0	0.0	0.0	0.0
Anchorage Municipal Light & Power	0.0	0.7	761.0	805.7	391.9
Arizona Public Service Company	1554.3	1578.1	1603.0	1661.1	1599.1
Arlington Valley, LLC - AVBA	869.1	876.0	869.6	863.9	869.7
Associated Electric Cooperative, Inc.	1424.1	1432.0	1472.8	1541.4	1467.6
Avangrid Renewables LLC	396.1	366.3	490.7	0.0	313.3
Avista Corporation	256.4	253.9	274.5	231.1	254.0
Balancing Authority of Northern California	553.2	730.3	587.6	690.4	640.4
Bonneville Power Administration	164.9	188.7	261.0	174.3	197.2
California Independent System Operator	451.6	429.4	365.2	399.5	411.4
Chugach Electric Assn Inc	804.0	818.0	910.2	858.0	847.6
City of Tacoma, Department of Public Utilities, Light Division	4.4	4.0	2.2	1.7	3.1
City of Tallahassee	774.8	761.2	807.7	917.5	815.3
Constellation Energy Control and Dispatch, LLC	774.8	870.7	871.5	869.7	846.7
Duke Energy Carolinas	531.6	512.0	591.6	626.1	565.3
Duke Energy Florida Inc	1029.4	992.3	1055.4	1205.1	1070.6
Duke Energy Progress East	512.6	491.2	610.8	638.8	563.3
Duke Energy Progress West	0.0	0.0	0.0	0.0	0.0
El Paso Electric Company	1122.8	1089.1	1083.2	1096.0	1097.8
Electric Reliability Council of Texas, Inc.	815.6	816.1	860.9	922.0	853.6
Florida Municipal Power Pool	1287.6	1247.7	1286.7	1371.9	1298.5
Florida Power & Light Company	608.1	620.7	631.7	646.2	626.7
Gainesville Regional Utilities	1229.7	1287.0	1252.4	1331.6	1275.2
Gridforce South	0.0	0.0	0.0	0.0	0.0
Hawaii Miscellaneous	855.9	858.9	1171.9	858.1	936.2
Hawaiian Electric Co Inc	1623.1	1668.4	1712.1	1685.3	1672.2
Idaho Power Company	231.4	162.2	148.5	96.7	159.7
Imperial Irrigation District	302.8	211.9	210.4	228.0	238.3
ISO New England Inc.	541.9	531.0	491.9	527.5	523.1
JEA	1114.6	1246.8	1253.7	1288.6	1225.9
LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities	1858.7	1852.1	1845.8	1889.7	1861.6
Los Angeles Department of Water and Power	1141.5	1091.1	1078.7	1135.1	1111.6
Midcontinent Independent Transmission System Operator, Inc..	1138.2	1072.2	1172.1	1292.9	1168.8
NaturEner Power Watch, LLC (GWA)	0.0	0.0	0.0	0.0	0.0
NaturEner Wind Watch, LLC	0.0	0.0	0.0	0.0	0.0

Nevada Power Company	797.8	801.9	829.2	830.7	814.9
New Brunswick System Operator	79.4	87.4	65.1	33.2	66.3
New Harquahala Generating Company, LLC - HGBA	842.6	0.0	0.0	1145.0	496.9
New York Independent System Operator	468.9	427.5	393.0	431.9	430.3
NorthWestern Energy (NWMT)	1575.4	1432.8	1732.3	1705.1	1611.4
PacifiCorp - East	1513.7	1616.8	1670.6	1684.9	1621.5
PacifiCorp - West	294.6	244.4	337.8	433.3	327.6
PJM Interconnection, LLC	813.4	760.4	807.2	870.3	812.8
Portland General Electric Company	724.1	887.5	934.9	854.4	850.2
Public Service Company of Colorado	829.5	907.3	940.4	996.5	918.4
Public Service Company of New Mexico	1133.7	1196.5	1271.4	1342.6	1236.1
Public Utility District No. 1 of Chelan County	0.0	0.0	0.0	0.0	0.0
Public Utility District No. 2 of Grant County, Washington	0.0	0.0	0.0	0.0	0.0
PUD No. 1 of Douglas County	0.0	0.0	0.0	0.0	0.0
Puerto Rico Miscellaneous	0.0	0.0	1537.3	0.0	384.3
Puget Sound Energy	626.8	521.2	658.9	568.4	593.8
Salt River Project	476.7	466.7	721.6	835.2	625.0
Seattle City Light	1.4	1.2	0.9	1.9	1.3
Seminole Electric Cooperative	1583.8	1605.2	1668.4	1725.7	1645.8
South Carolina Electric & Gas Company	807.2	712.0	773.7	923.6	804.1
South Carolina Public Service Authority	1722.3	1623.8	1627.4	1713.4	1671.7
Southeastern Power Administration	0.0	0.0	0.0	0.0	0.0
Southern Company Services, Inc. - Trans	892.3	857.2	966.6	1024.0	935.0
Southwest Power Pool	993.1	979.0	1063.4	1190.1	1056.4
Southwestern Power Administration	494.1	406.0	368.5	520.9	447.4
Tampa Electric Company	901.8	883.4	925.8	1100.2	952.8
Tennessee Valley Authority	649.7	560.3	682.2	748.5	660.2
Tucson Electric Power Company	1613.0	1548.9	1883.2	1914.5	1739.9
Turlock Irrigation District	943.4	863.7	807.3	828.9	860.8
Western Area Power Administration - Desert Southwest Region	494.1	380.6	312.5	275.2	365.6
Western Area Power Administration - Rocky Mountain Region	1894.7	1926.3	2007.6	1990.4	1954.7
Western Area Power Administration UGP West	0.0	0.0	0.0	0.0	0.0

[97] EPA. 2023. "Emissions & Generation Resource Integrated Database (eGRID), 2021" Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's eGRID web site: https://www.epa.gov/egrid.